Titan Energy, LLC
Form 10-K
April 17, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

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: 001-35317

TITAN ENERGY, LLC

(Exact name of registrant as specified in its charter)

Delaware	90-0812516
(State or other jurisdiction or incorporation or organization)	(I.R.S. Employer Identification No.)
Park Place Corporate Center One 1000 Commerce Drive, Suite 400	15275

Pittsburgh, PA
(Address of principal executive offices) Zip code

Registrant’s telephone number, including area code: 800-251-0171

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

None

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

Common shares representing limited liability company interests

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See 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	Non-accelerated filer	Smaller reporting company
			Emerging growth company

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.

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

The aggregate market value of the voting and non-voting equity securities held by non-affiliates of the registrant, based on the closing price of the registrant's predecessor's common units on the last business day of the registrant's most recently completed second quarter, June 30, 2016, was approximately $43.4 million.

The number of outstanding common shares of the registrant on April 12, 2017 was 5,447,787.

DOCUMENTS INCORPORATED BY REFERENCE: None

TITAN ENERGY, LLC

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GLOSSARY OF TERMS

On August 26, 2016, an order confirming the pre-packaged plan of reorganization (the "Plan") of our Predecessor and certain of its subsidiaries (collectively with our Predecessor, the "Predecessor Companies") was entered by the United States Bankruptcy Court for the Southern District of New York.

On September 1, 2016, the Predecessor Companies substantially consummated the Plan and emerged from their Chapter 11 Filings. As part of the transactions undertaken pursuant to the Plan, (i) our Predecessor's equity was cancelled, (ii) our Predecessor transferred all of its assets and operations to us as a new holding company and (iii) our Predecessor dissolved. As a result, we became the successor issuer to our Predecessor for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended (the "Exchange Act").

Unless the context requires otherwise or unless otherwise noted, all references in this report to:

- "the Company" or "the Successor" refer to Titan Energy, LLC (formerly known as Atlas Resource Finance Corporation) and its subsidiaries;
- our "Predecessor" or "ARP" refer to Atlas Resource Partners, L.P.
- "we," "our," "us" or like terms refer, after the consummation of the Plan, to the Company and, prior to the consummation of the Plan, to our Predecessor and the entirety of its business, assets and operations that were contributed to us in connection with the consummation of the Plan;
- our "Board" refer to the board of directors of the Company;
- "Titan Operating" refer to Titan Energy Operating, LLC, our wholly owned subsidiary, through which we hold the assets of our Predecessor;
- "Titan Management" refer to Titan Energy Management, LLC, a wholly owned subsidiary of ATLS; and
- "ATLS" refer to Atlas Energy Group, LLC.

Bbl. One barrel of crude oil, condensate or other liquid hydrocarbons equal to 42 United States gallons.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of gas to one Bbl oil, condensate or natural gas liquids.

Bpd. Barrels per day.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Common Shares. Our common shares representing limited liability company interests.

condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Partnerships. Tax-advantaged investment partnerships of which we are a sponsor and manager and in which we co-invest, to finance a portion of our natural gas, crude oil and NGLs production activities.

dry hole or well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EBITDA. Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.

exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well (as such terms are defined in the federal securities laws).

FASB. Financial Accounting Standards Board.

field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

fractionation. The process used to separate a natural gas liquid stream into its individual components.

GAAP. Generally Accepted Accounting Principles in the United States of America.

gross acres or gross wells. A gross well or gross acre is a well or acre in which the registrant owns a working interest.

LLC Agreement. Our amended and restated limited liability company agreement.

MLP. Master limited partnership.

MBbl. One thousand barrels of crude oil, condensate or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas; the standard unit for measuring volumes of natural gas.

Mcfe. Mcf of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcfd. One thousand cubic feet per day.

Mcfed. One Mcfe per day.

MMBbl. One million barrels of crude oil, condensate or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcfe. One million cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfed. One MMcfe per day.

net acres or net wells. A new well or net acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or net acres is the sum of the fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions of whole numbers.

natural gas liquids or NGLs —A mixture of light hydrocarbons that exist in the gaseous phase at reservoir conditions but are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus (the main constituent of condensates).

NYMEX. The New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

oil. Crude oil and condensate.

Plan Effective Date. September 1, 2016, the date that we emerged from the Chapter 11 Filings as the Successor.

productive well. A producing well or well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil and gas well.

proved developed reserves. Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

proved reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
 (a) The area identified by drilling and limited by fluid contacts, if any, and
 (b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 (a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
 (b) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

proved undeveloped reserves or PUDs. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. Present value of future net revenues. See the definition of “standardized measure.”

recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

SEC. Securities Exchange Commission.

standardized measure. Standardized measure, or standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities, is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

successful well. A well capable of producing oil and/or gas in commercial quantities.

undeveloped acreage or undeveloped acres. Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

working interest. An operating interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and the responsibility to pay royalties and a share of the costs of drilling and production operations under the applicable fiscal terms. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100.00% working interest in a lease burdened only by a landowner's royalty of 12.50% would be required to pay 100.00% of the costs of a well but would be entitled to retain 87.50% of the production.

FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “intend,” “m “might,” “plan,” “potential,” “predict,” “should,” or “will,” or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, 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. Some of the key factors that could cause actual results to differ from our expectations include:

- our ability to achieve the anticipated benefits from the consummation of the Chapter 11 Filings;
- the prices of natural gas, oil, NGLs and condensate;
- changes in the market price of our Common Shares;
- future financial and operating results;

- actions that we may take in connection with our liquidity needs, including the ability to service our debt, and ability to satisfy covenants in our debt documents;
- economic conditions and instability in the financial markets;
- the impact of our securities being quoted on the OTCQX Market rather than listed on a national exchange like the NYSE;
- success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves and meeting our substantial capital investment needs;
- the accuracy of estimated natural gas and oil reserves;
- the financial and accounting impact of hedging transactions;

- potential changes in tax laws and environmental and other regulations which may affect our operations;
- the ability to obtain adequate water to conduct drilling and production operations, and to dispose of the water used in and generated by these operations at a reasonable cost and within applicable environmental rules;
- the effects of unexpected operational events and drilling conditions, and other risks associated with drilling operations;
- impact fees and severance taxes;
- the effects of intense competition in the natural gas and oil industry;
- general market, labor and economic conditions and uncertainties;
- the ability to retain certain key customers;
- dependence on the gathering and transportation facilities of third parties;
- the availability of drilling rigs, equipment and crews;
- access to sufficient amounts of carbon dioxide for tertiary recovery operations;
- expirations of undeveloped leasehold acreage;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- exposure to new and existing litigation; and
- development of alternative energy resources.

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under “Risk Factors”. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

PART I

ITEM 1: BUSINESS

Overview

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and independent developer and producer of natural gas, crude oil and NGLs, with operations in basins across the United States with a focus on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. We are a sponsor and manager of Drilling Partnerships in which we co-invest, to finance a portion of our natural gas, crude oil and natural gas liquids production activities. As discussed further below, we are the Successor to the business and operations of ARP, a Delaware limited partnership organized in 2012.

Titan Management manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of ATLS, which is a publicly traded company (OTCQX).

We believe we have established a strong track record of growing our reserves, production and cash flows through a balanced mix of natural gas, oil and natural gas liquids exploitation and development, sponsorship of our Drilling Partnerships, and the acquisition of oil and gas properties. Our primary business objective is to generate growing yet stable cash flows through the development and acquisition of mature, long-lived natural gas, oil and natural gas liquids properties. As of December 31, 2016, our estimated proved reserves were 970 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 90% were proved developed and approximately 72% were natural gas. For the year ended December 31, 2016, our average daily net production was approximately 225.3 MMcfe.

Our operations include three reportable operating segments: gas and oil production, well construction and completion and other partnership management. For financial and other information about our reportable business segments refer to Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 16 to Item 8: Financial Statements and Supplementary Data.

Liquidity, Capital Resources, and Ability to Continue as a Going Concern

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, have negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

We are not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. In addition to the $30 million of indebtedness due on May 1, 2017, we classified the remaining $666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have $694.8 million of outstanding indebtedness under our credit facilities, which is net of $2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

Subject to receiving the remaining First Lien lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a "going concern" qualification. The First Lien lenders' waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility. Further, unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities—Credit Facility Amendment.”

Even following the amendment, we will continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. Please see “Risk Factors—Risks Related to Our Liquidity— Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.”

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with (i) lenders holding 100% of ARP’s senior secured revolving credit facility (the “First Lien Lenders”), (ii) lenders holding 100% of ARP’s second lien term loan (the “Second Lien Lenders”) and (iii) holders (the “Consenting Noteholders” and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the “Restructuring Support Parties”) of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the “7.75% Senior Notes”) and the 9.25% Senior Notes due 2021 (the “9.25% Senior Notes” and, together with the 7.75% Senior Notes, the “Notes”) of ARP’s subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the “Issuers”). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP’s restructuring (the “Restructuring”) pursuant to a pre-packaged plan of reorganization (the “Plan”).

Pursuant to the Restructuring Support Agreement, ARP completed the sale of certain of its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under ARP’s old senior secured revolving credit facility.

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”) in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court,” and the cases commenced thereby, the “Chapter 11 Filings”). The cases commenced thereby were jointly administered under the caption “In re: ATLAS RESOURCE PARTNERS, L.P., et al.”

ARP operated its businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in full in the ordinary course of business, and ARP’s existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the “Plan Effective Date”), pursuant to the Plan, the following occurred:

- the First Lien Lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than $440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a $410 million conforming reserve-based tranche and a $30 million non-conforming tranche.
- the Second Lien Lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of $252.5 million. In addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.
- Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

- ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended

- all of ARP’s preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

- Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members’ equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights. Four of the seven initial members of the board of directors of us were designated by Titan Management (the “Titan Class A Directors”). For so long as Titan Management holds the Series A Preferred Share, the Class A Directors will be appointed by a majority of the Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

Geographic and Geologic Overview

As of December 31, 2016, our significant gas and oil production positions were in the following six operating areas (refer to Item 2: “Properties” and Item 7: “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information regarding our gas and oil production positions). In connection with our ongoing liquidity enhancement initiatives, we are currently marketing our Appalachia, Raton and Rangely assets to concentrate our portfolio and grow our production through Eagle Ford development in 2017 and 2018.

Eagle Ford. The Eagle Ford Shale is an Upper Cretaceous-age formation that is prospective for horizontal drilling in approximately 26 counties across South Texas. Target vertical depths range from 4,000 to some 11,000+ feet with thickness from 40 to over 400 feet. The Eagle Ford formation is considered to be the primary source rock for many conventional oil and gas fields including the prolific East Texas Oil Field, one of the largest oil fields in the contiguous United States. We own 10,777 contiguous net acres in the Eagle Ford Shale in Atascosa County. We acquired our Eagle Ford position through a series of acquisitions in 2014 and 2015 for approximately $243 million. During the year, we averaged 9.9 MMcfe/d net production volumes. We estimate 83 Bcfe of total proved reserves for our Eagle Ford position, of which 89% are oil. At December 31, 2016, we had a one-rig program actively drilling on our Eagle Ford Shale position. We anticipate increasing to a two-rig program during the year ended December 31, 2017.

North Texas. Our North Texas position includes the Barnett Shale and Marble Falls play located east of the Bend Arch and west of the Ouachita Thrust in the Fort Worth Basin of northern Texas. The Barnett Shale is Mississippian-age shale formation located at depths between 5,000 and 8,000 feet and ranges in thickness from 100 and 600 feet. The Marble Falls play is a Pennsylvanian-age formation located above the Barnett Shale and beneath the

Atoka at depths of approximately 5,500 feet and ranges in thickness from 50 and 500 feet. We first acquired our positions in the Barnett Shale and Marble Falls play through several acquisitions in 2012, totaling approximately $653 million, and have continued to build our position through organic drilling. During the year, we averaged 41 MMcfe/d net production volumes. We estimate 115 Bcfe of total proved reserves for our North Texas positions, of which 94% are proved developed and producing (“PDP”).

Appalachian Basin. The Appalachian Basin includes all or parts of: Alabama, Georgia, Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. It is the most mature natural gas, crude oil and NGL producing region in the United States, having established the first oil production in 1860. Our development and production activities in the Appalachia Basin principally include the Marcellus Shale, Utica-Point Pleasant Shale, Clinton Sand and other conventional formations primarily in Pennsylvania and Ohio. During the year, we averaged 36,406 MMcfe/d net production volumes. We estimate 204 Bcfe of remaining proved reserves for our Appalachian positions, of which 95% are gas.

- The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet and ranges in thickness from 50 to 250 feet. We had an interest in approximately 251 Marcellus Shale wells, consisting of 212 vertical wells and 39 horizontal wells. We have an interest in eight horizontal Marcellus Shale wells in Northeastern Pennsylvania, all of which were developed through our Drilling Partnerships. Approximately 1,558 prospective Marcellus Shale acres remained undeveloped in Lycoming County, Pennsylvania.

- The Utica-Point Pleasant Shale is an Ordovician-age shale, which covers a large portion of Ohio, Pennsylvania, New York and West Virginia and lies several thousand feet below the Devonian-age Marcellus. The Utica-Point Pleasant is an organic rich system comprised of two related shales. The richest concentration of organic material is present within the Point Pleasant member of the Lower Utica formation; therefore, the primary objective section of this shale play. From central Ohio, the Utica-Point Pleasant play has gentle basin center dip towards its deepest point in central Pennsylvania. In general, as the present day depth increases from West to East, so does the progression of hydrocarbon maturity-along the following, ordered hydrocarbon phase windows: Immature-Oil-Condensate-Rich Gas-Dry Gas Windows. We have an interest in approximately 2,354 wells in Ohio including 12 horizontal Utica-Point Pleasant wells. We have approximately 1,395 net undeveloped acres prospective for the Utica Shale in Trumbull and Stark counties in Ohio.

Coal-Bed Methane. Our coal-bed methane developments are diversified across four well-known coal-bed methane producing areas: the Raton, Black Warrior, Arkoma and Central Appalachian basins. We have more than 476,491 net undeveloped acres prospective for coal-bed methane. We operated 2,783 wells and had an interest in another 910 wells, all of which produce gas generated from coal. During the year, we averaged 116 MMcfe/d net production volumes, representing over 51% of our total production for the year. We estimate 398 Bcfe of remaining proved reserves in our Coal-Bed Methane positions, of which 89% are PDP.

- The Raton asset straddles the New Mexico-Colorado border, along the eastern edge of the Sangre de Cristo Mountains. The production derives from two coal-bearing intervals, the Raton (Tertiary-Upper Cretaceous Age) and Vermajo (Cretaceous Age) formations. The combined net coal thickness ranges between 18 and 65 feet, with depths between 750 and 2,200 feet. We operate 972 wells in our Raton position.

- The Black Warrior coal-bed methane asset is located in central Alabama and geologically related with the frontal thrusts associated with the Appalachian Mountains. The three Pennsylvanian-age coal intervals (Pratt, Mary Lee and Black Creek, listed in increasing stratigraphic depth and age) possess combined net coal thicknesses ranging from 16 to 24 feet, at depths of 500 to 2,400 feet. We operate 858 wells and have an interest in an additional 696 wells in our Black Warrior position. We acquired our Raton and Black Warrior positions through an acquisition in 2013 for approximately $710 million.

- The Arkoma coal-bed methane asset is located in eastern Oklahoma and the Arkoma basin formed by the Ouachita Mountain uplift to the southeast. The main producing coal is the Hartshorne Coal seam which is of middle Pennsylvanian Age. The net coal thickness ranges from 5 to 10 feet, at depths of 14 to 4,900 feet. We operate 563 wells and have an interest in an additional 66 wells in our Arkoma position. We acquired our Arkoma position through an acquisition in 2015 for approximately $32 million.

- The Central Appalachian coal-bed methane asset is located in Virginia and West Virginia. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. We operate vertical wells in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia and pinnate horizontal wells in southern and northern West Virginia. We operate 411 wells and have an interest in an additional 72 wells in our Virginia and West Virginia positions. We acquired our Virginia and West Virginia positions through an acquisition in 2014 for approximately $98 million.

Rangely. The Rangely Oil Field, located in northwestern Colorado, is one of the oldest and largest oil fields in the Rocky Mountain region. We have an approximate 25% non-operating net working interest in the assets and Chevron Corporation is the current owner/operator of the Rangely Weber Sand Unit. The Weber Formation is Permian to Pennsylvanian in age (245-315 million years ago), and typically consists of fine-grained, cross-bedded calcareous sandstones. Average thickness of the unit is 1,200 feet, although the gross reservoir thickness averages 530 feet, and the net production interval within the formation varies from approximately 150 to 250 feet. We acquired our Rangely position through an acquisition in 2014 for approximately $410 million. Over the past 15 years, the Rangely field has exhibited a 3% exponential annual decline in production. During the year, we averaged 15 MMcfe/d net production volumes. We estimate 162 Bcfe of total remaining proved reserves in our Rangely position, of which 91% are oil and 81% are PDP.

Mid-Continent. Our Mid-Continent position includes the Mississippi Lime and Hunton formations located in the Anadarko Shelf in northern Oklahoma. The Mississippi Lime formation is an expansive carbonate hydrocarbon system and is located at depths between 4,000 and 7,000 feet between the Pennsylvanian-aged Morrow formation and the Devonian-age world-class source rock Woodford Shale formation. The Mississippi Lime formation can reach 600 feet in gross thickness, with a targeted porosity zone between 50 and 100 feet thickness. The Hunton formation is a limestone formation located at a depth of approximately 7,500 feet, and ranges in thickness from 150 and 300 feet. We acquired our Mississippi Lime position through a series of acquisitions in 2012 for approximately $60 million. During the year, we averaged 7 MMcfe/d net production volumes. We estimate 123 Bcfe of proved reserves in our Mid-Continent positions, of which 80% are gas. We also own significant salt water disposal assets in the area to support Mississippi Lime production.

Gas and Oil Production

Matters Impacting Comparability of Results

Fresh Start Accounting. Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of existing voting shares of our predecessor company received less than 50% of the voting shares of the post-emergence successor entity.

As a result of the application of fresh start accounting, at the Plan Effective Date, our assets and liabilities were recorded at their estimated fair values which, in some cases, are significantly different than amounts included in our financial statements prior to the Plan Effective Date. Accordingly, our financial condition, results of operations, and cash flows on and after the Effective Date are not comparable to our financial condition, results of operations, and cash flows prior to the Plan Effective Date. References to “Successor” relate to Titan on and subsequent to the Plan Effective Date. References to “Predecessor” refer to ARP prior to the Plan Effective Date. We have presented our financial condition, results of operations, and cash flows with a black line division to delineate the lack of comparability between the amounts presented on or after September 1, 2016 and dates prior.

Production Volumes

Currently, our natural gas, crude oil and NGL production operations are focused in various plays throughout the United States, and include direct interest wells and ownership interests in wells drilled through our Drilling Partnerships. When we drill new wells through our partnership management business we receive an interest in each Drilling Partnership proportionate to the value of our co-investment in it and the value of the acreage we contribute to it, typically 10-30% of the overall capitalization of a particular partnership. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day for the periods indicated:

	Successor Period From September 1, 2016 through December 31, 2016	Predecessor Period From January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production per day:				
Natural gas (Mcfd)	183,151	186,962	216,613	238,054
Oil (Bpd)	4,739	4,224	5,139	3,436
Natural gas liquids (Bpd)	2,021	2,296	3,155	3,802
Total (Mcfed)	223,708	226,083	266,374	281,486

Production Revenues, Prices and Costs

Our production revenues and estimated gas, oil and natural gas liquids reserves are substantially dependent on prevailing market prices for natural gas and oil prices. The following table presents our production revenues and average sales prices for our natural gas, oil and natural gas liquids production, along with our average production costs, taxes, and transportation and compression costs for the periods indicated:

	Successor Period From September 1, 2016 through December 31, 2016	Predecessor Period From January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production revenues (in thousands):(2)				
Natural gas revenue	$56,670	$89,223	$ 217,236	$ 318,920
Oil revenue	26,088	43,719	122,273	110,070
Natural gas liquids revenue	4,178	6,152	17,490	41,061
Total revenues	$86,936	$139,094	$ 356,999	$ 470,051
Average sales price:				
Natural gas (per Mcf):				
Total realized price, after hedge(1)(2)	$2.63	$3.34	$ 3.41	$ 3.76
Total realized price, before hedge(3)	$2.61	$1.91	$ 2.23	$ 3.93
Oil (per Bbl):				
Total realized price, after hedge(2)	$41.29	$70.38	$ 84.30	$ 87.76

Total realized price, before hedge	$45.12	$36.94	$ 44.19	$ 82.22
NGLs (per Bbl):				
Total realized price, after hedge[(2)]	$16.95	$10.98	$ 22.40	$ 29.59
Total realized price, before hedge	$16.95	$10.98	$ 12.77	$ 29.39
Production costs (per Mcfe):				
Lease operating expenses[(3)]	$1.10	$1.19	$ 1.34	$ 1.27
Production taxes	0.18	0.19	0.19	0.27
Transportation and compression	0.19	0.23	0.24	0.25
Total	$1.48	$1.60	$ 1.76	$ 1.80

(1) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effect of this subordination, the average realized gas sales price was $2.55 per Mcf ($2.54 per Mcf before the effects of financial hedging), $3.28 per Mcf ($1.84 per Mcf before the effects of financial hedging), $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging) and $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging) for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor years ended December 31, 2015 and 2014, respectively.

(2) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015 (see Item 8: “Financial Statements and Supplementary Data – Note 8”). Cash settlements on commodity derivative contracts

excluded from production revenues consisted of $0.4 million, $62.6 million and $48.6 million for natural gas and ($2.2) million, $26.4 million and $35.8 million for oil for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor year ended December 31, 2015, respectively. Cash settlements on natural gas liquids contracts excluded from production revenues consisted of $8.3 million for the Predecessor year ended December 31, 2015.

(3) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effects of these costs, total lease operating expenses per Mcfe were $1.07 per Mcfe ($1.44 per Mcfe for total production costs) and $1.15 per Mcfe ($1.57 per Mcfe for total production costs) for the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 and $1.32 per Mcfe ($1.74 per Mcfe for total production costs) and $1.25 per Mcfe ($1.77 per Mcfe for total production costs) for the Predecessor years ended December 31, 2015 and 2014, respectively.

Partnership Management Business

We conduct certain energy activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled “Liabilities Associated with Drilling Contracts” on our consolidated balance sheet. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 10-30%.

During the Successor period from September 1, 2016 through December 31, 2016 we raised $10.7 million from outside investors for participation in our Drilling Partnerships. During the Predecessor period from January 1, 2012 through August 31, 2016, we raised over $503.2 million from outside investors for participation in our Drilling Partnerships. Net proceeds from these partnerships are used to fund the investors’ share of drilling and completion costs under our drilling contracts with the partnerships.

Our fund raising activities for sponsored Drilling Partnerships during the last five years are summarized in the following table (amounts in millions):

	Drilling Program Capital		
	Investor contributions	Our contributions	Total capital
Successor period from September 1, 2016 through December 31, 2016	$10.7	$ 2.2	$12.9
Predecessor period from January 1, 2016 through August 31, 2016	—	—	—
Predecessor Year ended December 31, 2015	59.3	17.6	76.9
Predecessor Year ended December 31, 2014	166.8	71.0	237.8
Predecessor Year ended December 31, 2013	150.0	92.3	242.3
Predecessor Year ended December 31, 2012	127.1	54.4	181.5
Total	$513.9	$ 237.5	$751.4

We finance certain of our development drilling activities through the sponsor limited partnerships. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these Drilling Partnerships. Recently, we have experienced a significant decline in the amount of funds raised. In the future, we may not be successful in raising funds through these Drilling Partnerships at the same levels that we previously experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our Drilling Partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships. In the event that our Drilling Partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, we may have difficulty in maintaining or increasing the level of Drilling Partnership fundraising relative to the levels achieved by us. In this event, we may need to seek financing for our drilling activities through alternative methods, which may not be available, or which may be available only on a less attractive basis than the financing we realized through these Drilling Partnerships, or we may determine to reduce drilling activity.

As managing general partner of our Drilling Partnerships, we recognize our Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete the wells included within the partnership. Such fees are earned, in accordance with the partnership agreement, and recognized as the services are performed, typically between 60 and 270 days, using the percentage of completion method;
- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with the partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and
- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed;

Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

Our Drilling Partnerships provide tax advantages to our investors because an investor’s share of the partnership’s intangible drilling cost deduction may be used to offset ordinary income. Intangible drilling costs include items that do not have salvage value, such as labor, fuel, repairs, supplies and hauling. Generally, for our Drilling Partnerships, approximately 80% to 94% of the subscription proceeds received have been used to pay 100% of the partnership’s intangible drilling costs. For example, an investment of $10,000 generally permits the investor to deduct from taxable ordinary income approximately $8,000 to $9,400 in the year in which the investor invests.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Drilling Activity

The number of wells we drill will vary depending on, among other things, the amount of money we raise through our Drilling Partnerships, the cost of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table sets forth information with respect to the number of wells we drilled, both gross and for our interest, during the periods indicated.

	Successor Period From September 1, 2016 through December 31, 2016	Predecessor Period From January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Gross wells drilled[3]	—	2	28	129
Net wells drilled[1] [3]	—	2	17	67
Gross wells turned in line[2] [3]	15	—	36	119
Net wells turned in line[2] [3]	6	—	15	64

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage interest in our Drilling Partnerships.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.
(3) There were no exploratory wells drilled during any of the periods presented. There were no gross or net dry wells within our operating areas during any of the periods presented.

We do not operate any of the rigs or related equipment used in our drilling operations, relying instead on specialized subcontractors or joint venture partners for all drilling and completion work. This enables us to streamline our operations and conserve capital for investments in new wells, infrastructure and property acquisitions, while generally retaining control over all geological, drilling, engineering and operating decisions. We perform regular inspection, testing and monitoring functions on each of our Drilling Partnerships and our operated wells.

As of December 31, 2016, we did not have any ongoing drilling activities.

Natural Gas and Oil Leases

The typical oil and gas lease agreement provides for the payment of a percentage of the proceeds, known as a royalty, to the mineral owner(s) for all natural gas, oil and other hydrocarbons produced from any well(s) drilled on the leased premises. In the Appalachian Basin and much of the United States, this amount, historically, has ranged between 1/8th (12.5%) and 1/6th (16.66%) of the hydrocarbons produced, resulting in a net revenue interest to us of between 87.5% and 83.33%. With the discovery of the Marcellus and Utica Shales in the Appalachian Basin in the last few years, and the resultant competition for undeveloped acreage, it has become very common for landowners to demand royalty rates up to 20% or higher, resulting in a net revenue interest of 80% or less. In Oklahoma (Mississippi Lime play) and Texas (Barnett and Eagle Ford Shales and Marble Falls play), both states where we have acquired substantial acreage positions, royalties are commonly in the 15-25% range, resulting in net revenue interests to us in the 75-85% range.

In the Texas Barnett and Eagle Ford Shales, Oklahoma Mississippi Lime and Appalachian Basin Marcellus and Utica plays, where horizontal wells are generally drilled on much larger drilling units (sometimes approaching 1,000 acres), the mineral and/or surface rights are generally acquired from multiple parties. In the case of “urban” drilling areas in the Barnett Shale, there may be as many as 3,500 royalty owners within a single drilling unit.

Because the acquisition of hydrocarbon leases in highly desirable basins is an extremely competitive process, and involves certain geological and business risks to identify prospective areas, leases are frequently held by other oil and gas operators. In order to access the rights to drill on those leases held by others, we may elect to farm-in lease rights and/or purchase assignments of leases from competitor operators. Typically, the assignor of such leases will reserve an overriding royalty interest (over and above the existing mineral owner royalty), that can range from 2-3% up to as high as 7 or 8%, and sometimes contain options to convert the overriding royalty interests to working interests at payout of a well. Areas where farm-ins are utilized can result in additional reductions in our net revenue interests, depending upon their terms and how much of a particular drilling unit the farm-in acreage encompasses.

There will be occasions where competitors owning leasehold interests in areas where we want to drill will not farm-out or sell their leases, but will instead join us as working interest partners, paying their proportionate share of all drilling and operating costs in a well. However, it is generally our goal to obtain 100% of the working interest in any and all new wells that we operate.

Contractual Revenue Arrangements

Natural Gas. We market the majority of our natural gas production to gas purchasers directly or to third party midstream companies who gather, treat and process as necessary the gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Texas Eastern Transmission Corporation (TETCO) M2;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha but with smaller amounts sold into a variety of north Texas outlets;
- Raton – ANR, Panhandle, and NGPL;
- Black Warrior Basin – Southern Natural;
- Eagle Ford – Houston Ship Channel;

- Arkoma – Enable Gas; and
- Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

We sell the majority of our natural gas at monthly, fixed index first of the month prices and a smaller portion at index daily prices.

We hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation obligations held is approximately 65,000 MMBtu/d under contracts expiring in 2019 and 55,000 MMBtu/d under contracts expiring in 2020. We also hold firm transportation obligations on East Tennessee Natural Gas (25,000 MMBtu/d), Columbia Gas Transmission (14,000 MMBtu/d) and Equitrans (11,000 MMBtu/d) for the benefit of production from the central Appalachian Basin under contracts expiring between the years 2017 and 2024. We hold gathering obligations with ETC for production in the Barnett Shale. The total gathering obligations held is 2,507 mcf/d under contracts expiring in 2019. We do not have delivery commitments for fixed and determinable quantities of natural gas in any future periods under existing contracts or agreements.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is sold to an oil purchaser either directly or thru a common carrier acting on behalf of the oil purchaser. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking charges. The majority of our crude oil is sold via truck at the lease. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. We do not have delivery commitments or firm transportation obligations for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining “dry” gas to meet pipeline specifications for transport or sale to end users or purchasers operating on the receiving pipeline. The resulting plant residue natural gas is sold as described above and the NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional component indices. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a percentage retention by the processing and fractionation facility. We do not have delivery commitments or firm transportation obligations for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

For the Successor period September 1, 2016 through December 31, 2016, Tenaska Marketing Ventures and Chevron within our gas and oil production segment individually accounted for approximately 22% and 15%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor period January 1, 2016 through August 31, 2016, Tenaska Marketing Ventures, Chevron and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 16% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

Drilling Partnerships. We generally have funded a portion of our drilling activities through sponsorship of tax-advantaged Drilling Partnerships. In addition to providing capital for our drilling activities, our Drilling Partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. See “Partnership Management Business” for further discussion.

Natural Gas and Oil Hedging

We seek to provide greater stability in our cash flows through our use of financial hedges for our natural gas, oil and natural gas liquids production. The financial hedges may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures and options contracts with qualified counterparties. Financial hedges are contracts between ourselves and counterparties and do not require physical delivery of hydrocarbons. Financial hedges allow us to mitigate hydrocarbon price risk, and cash is settled to the extent there is a price difference between the hedge price and the actual NYMEX settlement price. Settlement typically occurs on a monthly basis, at the time in the future dictated within the hedge contract. Financial hedges executed in accordance with our secured credit facility do not require cash margin and are secured by our natural gas and oil properties. To assure that the financial instruments will be used solely for hedging price risks and not for speculative purposes, we have a management committee to assure that all financial trading is done in compliance with our hedging policies and procedures. We do not intend to contract for positions that we cannot offset with actual production.

Natural Gas Gathering Agreements

Virtually all natural gas produced is gathered through one or more pipeline systems before sale or delivery to a purchaser or an interstate pipeline. A gathering fee can be charged for each gathering activity that is utilized and by each separate gatherer providing the service. Fees will vary depending on the distance the gas travels and whether additional services such as compression, blending, or treating are provided.

Barnett and Marble Falls production in Texas is gathered/processed by a variety of companies depending on the location of the production. As in the case of Appalachian and Mississippi Lime production, either a fee is charged for the gathering activity alone, or a gatherer/processor may provide a combination of services to include processing, fractionation and/or compression. In some instances, the market to which the gas is sold will deduct the third-party gathering fees from the proceeds payable and pay the third-party gatherers directly.

In Appalachia, we have gathering agreements with Laurel Mountain Midstream, LLC (“Laurel Mountain”). Under these agreements, we dedicate our natural gas production in certain areas within southwest Pennsylvania to Laurel Mountain for transportation to interstate pipeline systems or local distribution companies, subject to certain exceptions. In return, Laurel Mountain is required to accept and transport our dedicated natural gas subject to certain conditions. The greater of $0.35 per mcf or 16% of the gross sales price of the natural gas is charged by Laurel Mountain for the majority of the gas. A lesser fee does apply to a small number of specific wells in the area. We also use Anadarko Marcellus Midstream, L.L.C.'s facilities to gather our Lycoming Co., Pennsylvania production for a $0.45 MMBtu fee which delivers our production to Transco Leidy Line pipeline for sale to our purchaser. Our Utica production in Ohio is gathered by both Utica East Ohio Midstream, L.L.C. ("UEO") and Blue Racer Midstream, L.L.C. for delivery to UEO's Kensington Processing plant. Residue gas is sold to purchasers on Dominion East Ohio or Tennessee pipelines. UEO markets the NGLs and returns proceeds to us.

In the Raton Basin (New Mexico and Colorado), we gather all of our production and deliver it to Colorado Interstate Gas Pipeline, an interstate pipeline. In the Black Warrior Basin (Alabama), we gather our own production and deliver it to the Southcross Alabama pipeline who then delivers the gas to the Sothern Natural pipeline to our purchaser.

Mississippi Lime production is currently gathered and processed by SemGas and plant products including gas and NGLs are sold to SemGas. SemGas returns 95 Percent of Proceeds ("POP") of the revenues it receives to Titan from the sale of gas and NGLs. The remaining 5% and a $0.3276 MMBtu gathering fee are paid to SemGas for all services provided.

Availability of Energy Field Services

We contract for drilling rigs and purchase goods and services necessary for the drilling and completion of wells from a number of drillers and suppliers, none of which supplies a significant portion of our annual needs. Over the past year, we and other oil and natural gas companies have experienced a significant reduction in drilling and operating costs. We cannot predict the duration or stability of the current level of supply and demand for drilling rigs and other goods and services required for our operations with any certainty due to numerous factors affecting the energy industry, including the supply and demand for natural gas and oil.

Competition

The energy industry is intensely competitive in all of its aspects. We operate in a highly competitive environment for acquiring properties and other energy companies, attracting capital for our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. We also compete with the exploration and production divisions of public utility companies for mineral property acquisitions. Competition is intense for the acquisition of leases considered favorable for the development of hydrocarbons in commercial quantities. Our competitors may be able to pay more for hydrocarbon properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Furthermore, competition arises not only from numerous domestic and foreign sources of hydrocarbons but also from other industries that supply alternative sources of energy. Product availability and price are the principal means of competition in selling natural gas, crude oil, and natural gas liquids.

Many of our competitors possess greater financial and other resources which may enable them to identify and acquire desirable properties and market their hydrocarbon production more effectively than we do. Moreover, we also compete with a number of other companies that offer interests in Drilling Partnerships. As a result, competition for investment capital to fund Drilling Partnerships is intense.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. In addition, seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas. These seasonal anomalies may pose challenges for meeting our well construction objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay our operations. We have in the past drilled a greater number of wells during the winter months, because we typically received the majority of funds from Drilling Partnerships during the fourth calendar quarter.

Environmental Matters and Regulation

Our operations relating to drilling and waste disposal are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As operators within the complex natural gas and oil industry, we must comply with laws and regulations at the federal, state and local levels. These laws and regulations can restrict or affect our business activities in many ways, such as by:

- restricting the way waste disposal is handled;

- limiting or prohibiting drilling, construction and operating activities in sensitive areas such as wetlands, coastal regions, non-attainment areas, tribal lands or areas inhabited by threatened or endangered species;
- requiring the acquisition of various permits before the commencement of drilling;
- requiring the installation of expensive pollution control equipment and water treatment facilities;
- restricting the types, quantities and concentration of various substances that can be released into the environment in connection with siting, drilling, completion, production, and plugging activities;
- requiring remedial measures to reduce, mitigate and/or respond to releases of pollutants or hazardous substances from existing and former operations, such as pit closure and plugging of abandoned wells;
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations;
- imposing substantial liabilities for pollution resulting from operations; and
- requiring preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where pollutants or wastes have been disposed or otherwise released. Neighboring landowners and other third parties can file claims for personal injury or property damage allegedly caused by noise and/or the release of pollutants or wastes into the environment. These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently enact new, and revise existing, environmental laws and regulations, and any new laws or changes to existing laws that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations, and compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, we cannot assure future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Environmental laws and regulations that could have a material impact on our operations include the following:

National Environmental Policy Act. Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or “NEPA.” NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly affect the environment. In the course of such evaluations, an agency will typically require an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that will be made available for public review and comment. All of our proposed exploration and production activities on federal lands, if any, require governmental permits, many of which are subject to the requirements of NEPA. This process has the potential to delay the development of natural gas and oil projects.

Hydraulic Fracturing. In recent years, federal, state, and local scrutiny of hydraulic fracturing has increased. Regulation of the practice remains largely the province of state governments, except for a Bureau of Land Management rule that would have imposed conditions on fracturing operations on federal lands, which was enjoined by a federal court holding BLM lacked the authority to adopt the rule. Common elements of state regulations governing hydraulic fracturing may include, but not be limited to, the following: requirement that logs and pressure test results are included in disclosures to state authorities; disclosure of hydraulic fracturing fluids and chemicals, potentially subject to trade secret/confidential proprietary information protections, and the ratios of same used in operations; specific disposal regimens for hydraulic fracturing fluids; replacement/remediation of contaminated water assets; and minimum depth of hydraulic fracturing. In December 2016, EPA released the final report of its study of the impacts of hydraulic fracturing on drinking water in the U.S. finding that the hydraulic fracturing water cycle can impact drinking water resources under some circumstances. Those circumstances included where (1) there are water withdrawals for hydraulic fracturing in times or areas of low water availability, (2) hydraulic fracturing fluids and chemicals or produced water are spilled, (3) hydraulic fracturing fluids are injected into wells with inadequate mechanical integrity, and (4) hydraulic fracturing wastewater is stored or disposed in unlined pits. If new federal regulations were adopted as a result of these findings, they could increase our cost to operate.

Oil Spills. The Oil Pollution Act of 1990, as amended ("OPA"), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, the federal regulations that implement the Clean Water Act, and analogous state laws and regulations a number of different types of requirements on our operations. First, these laws and regulations impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the relevant state. These permits may require pretreatment of produced waters before discharge. Compliance with such permits and requirements may be costly. Second, the Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The precise definition of waters and wetland subject to the dredge-and-fill permit requirement has been enormously complicated and is subject to on-going litigation. A broader definition could result in more water and wetlands being subject to protection creating the possibility of additional permitting requirements for some of our existing or future facilities. Third, the Clean Water Act also requires specified facilities to maintain and implement spill prevention, control and countermeasure plans and to take measures to minimize the risks of petroleum spills. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for failure to obtain or non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe that our operations are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, the federal regulations that implement the Clean Air Act, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including drilling sites, processing plants, certain storage vessels and compressor stations, and also impose various monitoring and reporting requirements. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of customer compliance to the point where demand for natural gas is affected. Clean Air Act rules impose additional emissions control requirements and practices on some of our operations. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new or revised requirements. These regulations may increase the costs of compliance for some facilities. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that our operations are in substantial compliance with the requirements of the Clean Air Act and comparable state laws and regulations. While we will likely be required to incur certain capital expenditures in the future for air pollution control equipment to comply with applicable regulations and to obtain and maintain operating permits and approvals for air emissions, we believe that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than other similarly situated companies.

Greenhouse Gas Regulation and Climate Change. To date, legislative and regulatory initiatives relating to greenhouse gas emissions have not had a material impact on our business. Under the past eight years during the Obama Administration several Clean Air Act regulations were adopted to reduce greenhouse gas emissions, and a couple foundational regulations were upheld by the courts. President Trump pledged during the election campaign to suspend or reverse many if not all of the Obama Administration's initiatives to reduce the nation's emissions of greenhouse gases. Some of the foundational regulations, however, appear unyielding. It would be a significant departure from the principle of stare decisis for the Supreme Court to reverse its decision in Massachusetts v. EPA, 549 U.S. 497 (2007) holding that greenhouse gases are "air pollutants" covered by the Clean Air Act. Similarly, reversing EPA's final determination that greenhouse gases "endanger" public health and welfare, 74 Fed. Reg. 66,496 (Dec. 15, 2009), upheld in Coalition for Responsible Regulation, Inc. v. EPA, 684 F.3d 102 (D.C. Cir. 2012), would seem to require development of new scientific evidence that runs counter to general discoveries since that determination.

On March 28, 2017, President Trump issued an Executive Order on Promoting Energy Independence and Economic Growth explaining how his Administration would withdraw, rescind, revisit, or revise virtually every element of the Obama Administration's program for reducing greenhouse gas emissions. Under the Executive Order, some actions had immediate effect. Other actions, including those most directly affecting our operations and the overall consumption of fossil fuels, will be the subject of potentially lengthy notice-and-comment rule-making. With respect to rules more directly applicable to the types of operations we conduct, the Executive Order directed EPA to undertake new rule-making to revise or rescind 2015 methane emissions standards for new or modified wells. Similarly, the Order directed the Department of Interior to re-write a 2015 rule imposing restrictions on fracturing operations conducted on federal land and a 2016 rule restricting flaring of methane emissions from oil and gas extraction on federal land. With respect to rules of greater applicability affecting overall consumption of fossil fuels, the Order instructed EPA to rewrite (1) the 2015 Clean Power Plan – the rule aimed at reducing greenhouse gas emissions from existing power plants by one-third (compared to 2005 levels), and (2) the 2015 New Source Rule setting greenhouse gas emission requirements for construction of new power plants.

While we generally foresee a less stringent approach to the regulation of greenhouse gases, undoing the Obama Administration's regulations of greenhouse gas emissions will necessarily involve lengthy notice-and-comment rulemaking and the resulting decisions may then be subject to litigation by those opposed to rolling back existing regulations. Thus, it could be several years before existing regulations are off the books. Opponents of the rollbacks, including states and environmental groups, may then decide to sue large sources of greenhouse gas emissions for the alleged nuisance created by such emissions. In 2011, the Supreme Court held that federal common law nuisance claims were displaced by the EPA's authority to regulate greenhouse gas emissions from large sources of emissions. If the Administration fails to pursue regulation of emissions from such sources or takes the position that it has no authority to do regulate their emissions, then it is possible that a court would find common law nuisance claims are no longer displaced.

Although further regulation of greenhouse gas emissions from our operations may stall at the federal level, it is possible that, in the absence of additional federal regulatory action, states may pursue additional regulation of our operations, including restrictions on new and existing wells and fracturing operations, as many states already have done.

Waste Handling. The Solid Waste Disposal Act, including RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and the disposal of non-hazardous wastes. With authority granted by federal EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil and natural gas constitute "solid wastes," which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous in the future. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as "solid waste." The transportation of natural gas in pipelines may also generate some "hazardous wastes" that are subject to RCRA or comparable state law requirements. We believe that our operations are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations. More stringent regulation of natural gas and oil exploration and production wastes could increase the costs to manage and dispose of such wastes.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered under the statute to be responsible for the release of a "hazardous substance" (but excluding petroleum) into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Our operations are, in many cases, conducted at properties that have been used for natural gas and oil exploitation and production for many years. Although we believe that we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances may have been released on or under the properties owned or leased by us or on or under other locations, including off-site locations, where such substances have been taken for disposal. We are not presently aware the need for us to respond to releases of hazardous substances that would impose costs that would be material to our financial condition.

OSHA and Chemical Reporting Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act, or “OSHA,” and comparable state statutes. On March 25, 2016, OSHA published its final Occupational Exposure to Respirable Crystalline Silica final rule, which imposes specific requirements to protect workers engaged in hydraulic fracturing. 81 Fed. Reg. 16,285. The requirements of that final rule as it applies to hydraulic fracturing become effective June 23, 2018, except for the engineering controls component of the final rule, which has a compliance date of June 23, 2021. We expect implementation of the rule to result in significant costs. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. If the sectors to which community-right-to-know or similar chemical inventory reporting are expanded, our regulatory burden could increase. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans and can result in death. We conduct our natural gas extraction activities in certain formations where hydrogen sulfide may be, or is known to be, present. We employ numerous safety precautions at our operations to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

Drilling and Production. State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our or its wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax or impact fee with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

State Regulation and Taxation of Drilling. The various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Pennsylvania has imposed an impact fee on wells drilled into an unconventional formation, which includes the Marcellus Shale. The impact fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. For example, based upon natural gas prices for 2015, the impact fee for qualifying unconventional horizontal wells spudded during 2015 was $45,300 per well, while the impact fee for unconventional vertical wells was $9,100 per well. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded, and the fee will continue for 15 years for an unconventional horizontal well and 10 years for an unconventional vertical well. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources.

States may regulate rates of production and may establish maximum limits on daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, the type of wells that may be drilled in the future in proximity to existing wells and to limit the number of wells or locations from which we can drill. Texas imposes a 7.5% tax on the market value of natural gas sold, 4.6% on the market value of condensate and oil produced and an oil field clean up regulatory fee of $0.000667 per Mcf of gas produced, a regulatory tax of $.001875 and the oil field clean-up fee of $.00625 per barrel of crude. New Mexico imposes, among other taxes, a severance tax of up to 3.75% of the value of oil and gas produced, a conservation tax of up to 0.24% of the oil and gas sold, and a school emergency tax of up to 3.15% for oil and 4% for gas. Alabama imposes a production tax of up to 2% on oil or gas and a privilege tax of up to 8% on oil or gas. Oklahoma imposes a gross production tax of 7% per Bbl of oil, up to 7% per Mcf of natural gas and a petroleum excise tax of .095% on the gross production of oil and gas.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon our unitholders.

Other Regulation of the Natural Gas and Oil Industry. The natural gas and oil industry is extensively regulated by federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in their industries with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the potential costs to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Employees

We do not directly employ any of the persons responsible for our management or operation. In general, personnel employed by ATLS manage and operate our business. As of December 31, 2016, approximately 389 ATLS employees provided direct support to our operations.

Available Information

We make our periodic reports under the Exchange Act, including our annual report on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K, and any amendments to those reports, available through our website at www.titanenergyllc.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. To view these reports, click on “Investor Relations”, then “SEC Filings”. The other information contained on or hyperlinked from our website does not constitute part of this report. You may also receive, without charge, a paper copy of any such filings by request to us at Park Place Corporate Center One, 1000 Commerce Drive, Suite 400, Pittsburgh, Pennsylvania 15275, telephone number (800) 251-0171. A complete list of our filings is available on the SEC’s website at www.sec.gov. Any of our filings are also available at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

ITEM 1A: RISK FACTORS

Limited liability company interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider those risk factors included herein, together with all of the other information included in this report, including the matters addressed under "Forward-Looking Statements," in evaluating an investment in our Common Shares.

If any of the following risks were to occur, our business, financial condition, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our Common Shares could decline and you could lose all or part of your investment.

Risks Related to Our Liquidity

Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. Pursuant to the expected amendment to our First Lien Facility, the borrowing base will be substantially reduced in the near future. Our cash on hand and cash flow from operations are not sufficient to continue to fund our operations and allow us to satisfy our obligations.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. However, there is no guarantee that the proceeds we receive for any asset sale will satisfy the repayment requirements under our First Lien Facility.

We cannot assure you that we would be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that would be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions would allow us to meet our debt obligations and capital requirements.

Please see "Management's Discussion and Results of Operations— Liquidity, Capital Resources and Ability to Continue as a Going Concern."

Our substantial indebtedness could adversely affect our financial health and prevent us from fulfilling our debt obligations.

On September 1, 2016, we and Titan Operating, as borrower, entered into the First Lien Credit Facility and the Second Lien Credit Facility, which together currently have approximately $694.8 million aggregate principal amount of debt outstanding as of December 31, 2016. Our high level of indebtedness could have important consequences for an investment in us and significant effects on our business. For example, our high level of indebtedness, the funds required to service such debt and the terms of our debt agreements may:

- require a substantial portion of our cash flow to make interest payments on the debt and reduce the cash flow available to fund capital expenditures and to grow our business;
- make it more difficult for us to satisfy our financial obligations under our indebtedness and our contractual and commercial commitments and increase the risk that we may default on our debt obligations;
- increase our vulnerability to downturns in our business, our industry or in the general economy and restrict us from exploiting business opportunities or making acquisitions;

- limit our flexibility in planning for, or reacting to, changes in our business and the industry;
- place us at a competitive disadvantage relative to our competitors that may not be as leveraged with debt;
- limit our ability to obtain additional financing for working capital, capital expenditures, acquisitions and other investments, or general corporate purposes, which may limit our ability to execute our business strategy;
- limit our ability to refinance our indebtedness on terms that are commercially reasonable, or at all;
- limit management's discretion in operating our business; and
- result in higher interest expense if interest rates increase and we have outstanding floating rate borrowings.

Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to satisfy our other debt obligations will depend on our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control.

Subject to receiving the remaining First Lien lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a "going concern" qualification. The First Lien lenders' waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility.

In addition, the expected amendment to our First Lien Credit Facility will result in substantial reductions in our borrowing base in the near future, and we do not currently have sufficient liquidity to make the required repayments. In such event, we may be required to enter into discussions with our First Lien lenders or take other actions, and there can be no guarantee that any such discussions or actions would be successful. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. However, there is no guarantee that the proceeds we receive for any asset sale will satisfy the repayment requirements under our First Lien Facility.

Further, unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. However, pursuant to the intercreditor agreement, the lenders under the Second Lien Facility are restricted in their ability to pursue remedies for 180 days from any such notice of default. As of the date hereof, the lenders under the Second Lien Facility have not yet given us notice of any default.

If we cannot make the required payments under our credit facilities, including as a result of a borrowing base redetermination to an amount below our outstanding borrowings, an event of default would result thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our oil and gas properties and our ownership interests in a majority of the material operating subsidiaries as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities.

Our ability to continue as a going concern is dependent upon our ability to sell a significant amount of non-core assets or raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern. The report of our independent registered public accounting firm that accompanies the audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern.

Our debt obligations and covenants in our credit facilities restrict our business in many ways and may have a negative impact on our financing options and liquidity position.

Our debt obligations and covenants in our credit facilities could restrict our business in many ways. For example, our First Lien Credit Facility and Second Lien Credit Facility may contain various restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness or grant liens;
- make loans or investments;
- make restricted payments;
- issue preferred stock;
- make distributions from restricted subsidiaries;
- take on debt of unrestricted subsidiaries;
- enter into commodity or interest rate swap arrangements;
- sell assets and subsidiary stock;
- sell all or substantially all of our assets;
- enter into certain transactions with affiliates;
- sell or discount of receivables; and
- merge into or consolidate with other persons.

In addition, our credit facilities require us to maintain specified financial ratios.

Our ability to meet those financial ratios can be affected by events beyond our control, and we may be unable to meet those tests. If we are unable to meet any of the covenants in our credit facilities, we may be required to enter into discussions with our lenders or take other actions, which may negatively impact the price of our securities.

A breach of any of the covenants in our credit facilities could result in an event of default thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities.

In addition, our borrowings under our credit facilities are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

To the extent that we incur additional indebtedness, the risks described above could increase and the additional debt obligations might subject us to additional and different restrictive covenants that could further affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on acceptable terms or at all.

Risks Related to the Chapter 11 Filings

The Chapter 11 Filings may have a negative impact on our image, which may negatively impact our business going forward.

Negative events or publicity associated with our Chapter 11 Filings could adversely affect our relationships with our suppliers, service providers, customers, employees, and other third parties. In addition, we may face greater difficulties in attracting, motivating and retaining management. These and other related issues could adversely affect our operations and financial condition.

Even following the consummation of the Plan, we may not be able to achieve our stated goals and continue as a going concern.

Even following the consummation of the Plan, we continue to face a number of risks, including further deterioration in commodity prices or other changes in economic conditions, changes in our industry, changes in demand for our oil and gas and increasing expenses. Accordingly, we cannot guarantee that the Plan will achieve our stated goals.

Furthermore, even following the reduction in our debts as a result of the consummation of the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited, if it is available at all.

Our ability to continue as a going concern is dependent upon our ability to raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern. The report of our independent registered public accounting firm that accompanies the audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern.

Our financial results may be volatile and may not reflect historical trends.

Following the consummation of the Plan, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments may significantly impact our consolidated financial performance. As a result, our historical financial performance is likely not indicative of our financial performance following the commencement of the Chapter 11 Filings.

In addition, following the consummation of the Plan, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to a plan of reorganization. We adopted fresh-start accounting, in which case our assets and liabilities have been recorded at fair value as of the fresh-start reporting date, which differ materially from the recorded values of assets and liabilities on our Predecessor's consolidated balance sheets. Our financial results after the application of fresh-start accounting also may be different from historical trends.

Risks Relating to Our Business

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil, which have declined substantially. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Continued depressed prices in the future would have a negative impact on our future financial results and could result in an impairment charge. Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of natural gas and oil supply and demand and expectations regarding supply and demand, including the potential long- term impact of an abundance of natural gas and oil (such as that produced from our Marcellus Shale properties) on the domestic and global natural gas and oil supply;
- the level of industrial and consumer product demand;
- weather conditions;
- fluctuating seasonal demand;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level of foreign imports;

- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to other major currencies.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2016, the NYMEX Henry Hub natural gas index price ranged from a high of $3.93 per MMBtu to a low of $1.64 per MMBtu, and West Texas Intermediate (“WTI”) oil prices ranged from a high of $54.06 per bbl to a low of $26.21 per bbl.

A continuation of the prolonged substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition and results of operations. We may use various derivative instruments in connection with anticipated oil and natural gas sales to reduce the impact of commodity price fluctuations. Specifically, the First Lien Credit Facility requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017. However, the entire exposure of our operations from commodity price volatility is not currently hedged, and we may not be able to hedge such exposure going forward. To the extent we do not hedge against commodity price volatility, or our hedges are not effective, our results of operations and financial position may be further diminished.

In addition, low oil and natural gas prices have reduced, and may in the future further reduce, the amount of oil and natural gas that can be produced economically by our operators. This scenario may result in our having to make substantial downward adjustments to our estimated proved reserves, which could negatively impact our borrowing base and our ability to fund our operations. If this occurs or if production estimates change or exploration or development results deteriorate, successful efforts method of accounting principles may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices.

Drilling for and producing natural gas and oil are high-risk activities with many uncertainties.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. This risk is exacerbated by the current decline in oil and gas prices. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;

- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;

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- formations with abnormal pressures;
- injury or loss of life and property damage to a well or third-party property;
- leaks or discharges of toxic gases, brine, natural gas, oil, hydraulic fracturing fluid and wastewater from a well;
- environmental accidents, including groundwater contamination;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of natural gas or well fluids.

Any one or more of the factors discussed above could reduce or delay our receipt of drilling and production revenues, thereby reducing our earnings, and could reduce revenues in one or more of our Drilling Partnerships, which may make it more difficult to finance our drilling operations through sponsorship of future partnerships. In addition, any of these events can cause substantial losses, which may not fully be covered by insurance, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties, which could reduce our cash flow.

Although we maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could reduce our results of operations.

We may not be able to continue to raise funds through our Drilling Partnerships at desired levels, which may in turn restrict our ability to maintain our drilling activity at recent levels.

We sponsor limited and general partnerships to finance certain of our development drilling activities. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these Drilling Partnerships. We raised $10.7 million, $59.3 million, $166.8 million and $150.0 million in 2016, 2015, 2014, and 2013, respectively. We experienced a significant decline in raising funds in 2016. In the future, we may not be successful in raising any funds through these Drilling Partnerships or at the same levels that we previously experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our Drilling Partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships. In addition, our fee-based revenues will be based on the number of Drilling Partnerships we sponsor and the number of partnerships and wells we manage or operate. If we are unsuccessful in sponsoring future Drilling Partnerships, our fee-based revenues may decline.

We have agreed to subordinate a portion of our share of production revenues, net of corresponding production costs, to specified returns to the investor partners in the Drilling Partnerships, typically 10% to 12% per year for the first five to eight years of distributions. Thus, our revenues from a particular partnership will decrease if we do not achieve the specified minimum return. In the event that our Drilling Partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, we may have difficulty in maintaining or increasing the level of Drilling Partnership fundraising relative to the levels achieved by us. In this event, we may need to seek financing for our drilling activities through alternative methods, which may not be available, or which may be available only on a less attractive basis than the financing we realized through these Drilling Partnerships, or we may determine to reduce drilling activity.

Changes in tax laws may impair our ability to obtain capital funds through Drilling Partnerships.

Under current federal tax laws, there are tax benefits to investing in Drilling Partnerships, including deductions for intangible drilling costs and depletion deductions. However, from time to time members of Congress introduce legislation that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs and certain environmental clean-up costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. The repeal of these oil and gas tax benefits, if it happens, would result in a substantial decrease in tax benefits associated with an investment in our Drilling Partnerships. These or other changes to federal tax law may make investment in the Drilling Partnerships less attractive and, thus, reduce our ability to obtain funding from this significant source of capital funds.

Competition in the natural gas and oil industry is intense, which may hinder our ability to acquire natural gas and oil properties and companies and to obtain capital, contract for drilling equipment and secure trained personnel.

We operate in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. Our competitors may be able to pay more for natural gas, natural gas liquids and oil properties and drilling equipment and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Moreover, our competitors for investment capital may have better track records in their programs, lower costs or stronger relationships with participants in the oil and gas investment community than we do. All of these challenges could make it more difficult for us to execute our growth strategy. We may not be able to compete successfully in the future in acquiring leasehold acreage or prospective reserves or in raising additional capital.

Furthermore, competition arises not only from numerous domestic and foreign sources of natural gas and oil but also from other industries that supply alternative sources of energy. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Product availability and price are the principal means of competition in selling natural gas and oil. Many of our competitors possess greater financial and other resources than we do, which may enable them to identify and acquire desirable properties and market their natural gas and oil production more effectively than we can.

Our operations require substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our asset base will decline, which could cause our revenues to decline.

The natural gas and oil industry is capital intensive. If we are unable to obtain sufficient capital funds on satisfactory terms, we may be unable to increase or maintain our inventory of properties and reserve base, or be forced to curtail drilling or other activities. This could cause our revenues to decline and diminish our ability to service any debt that we may have at such time. If we do not make sufficient or effective capital expenditures, including with funds from third-party sources, we will be unable to expand our business operations. In addition, the Chapter 11 Filings have added complexity to our ability to fund capital expenditures.

Economic conditions and instability in the financial markets could negatively impact our business.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the Chinese economy have contributed to economic uncertainty and concerns for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and could lead to a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids produced from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and potential cash available for distribution.

The above factors can also cause volatility in the markets and affect our ability to raise capital and reduce the amount of cash available to fund operations. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. Disruptions in the capital and credit markets could negatively impact our access to liquidity needed for our businesses and impact flexibility to react to changing economic and business conditions. We may be unable to execute our growth strategies, take advantage of business opportunities, respond to competitive pressures or service our debt, any of which could negatively impact our business.

A continuing or weakening of the current economic situation could have an adverse impact on producers, key suppliers or other customers, or on our lenders, causing them to fail to meet their obligations. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow could be impacted. The uncertainty and volatility surrounding the global financial system may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities or our costs of operation potentially rising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

We depend on certain key customers for sales of our natural gas, crude oil and natural gas liquids. To the extent these customers reduce the volumes of natural gas, crude oil and natural gas liquids they purchase or process from us, or cease to purchase or process natural gas, crude oil and natural gas liquids from us, our revenues and cash available for distribution could decline.

We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. Crude oil produced from our wells flow directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining “dry” gas (low Btu content) to meet pipeline specifications for transport to end users or marketers operating on the receiving pipeline. For the Successor period September 1, 2016 through December 31, 2016, Tenaska Marketing Ventures and Chevron within our gas and oil production segment individually accounted for approximately 22% and 15%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor period January 1, 2016 through August 31, 2016, Tenaska Marketing Ventures, Chevron and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 16% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. To the extent these and other key customers reduce the amount of natural gas, crude oil and natural gas liquids they purchase from us, our revenues and cash flow could temporarily decline in the event we are unable to sell to additional purchasers.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price that we receive for our production could significantly reduce our cash available for distribution and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price that we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead price that we receive could significantly reduce our cash flow and adversely affect our financial condition. We use the relevant benchmark price to calculate our hedge positions, and we do not have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that may expire in the near future.

As of December 31, 2016, leases covering approximately 11,519 of our 730,885 net undeveloped acres, or 1.6%, are scheduled to expire on or before December 31, 2017. An additional 0.1% of our net undeveloped acres are scheduled to expire in 2018. No leases are scheduled to expire in 2019. If we are unable to renew these leases or any leases scheduled for expiration beyond their expiration date, on favorable terms, we will lose the right to develop the acreage that is covered by an expired lease.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would reduce our cash flow from operations and income.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves. Our ability to find and acquire additional recoverable reserves to replace current and future production at acceptable costs depends on our ability to generate sufficient cash flow from operations and other sources of capital, principally from the sponsorship of new Drilling Partnerships, all of which are subject to the risks discussed elsewhere in this section.

Decreases in commodity prices could subject our oil and gas properties to a non-cash impairment loss under U.S. generally accepted accounting principles.

U.S. generally accepted accounting principles require oil and gas properties and other long-lived assets to be reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. We test our oil and gas properties on a field-by-field basis, by determining if the historical cost of proved properties less the applicable depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on our economic interests and our plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based on current contracts in place at the impairment testing date, adjusted for basis differentials and market related information, including published future prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates.

Prolonged depressed prices of natural gas and oil may cause the carrying value of our oil and gas properties to exceed the expected future cash flows, and a non-cash impairment loss would be required to be recognized in the financial statements for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. For the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, there were no impairments of proved gas and oil properties.

Estimates of reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Underground accumulations of natural gas and oil cannot be measured in an exact way. Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Our current estimates of our proved reserves are prepared by our internal engineers and our independent petroleum engineers. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates were made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Our standardized measure is calculated using natural gas prices that do not include financial hedges. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. We base the estimated discounted future net cash flows from our proved reserves on historical prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the amount and timing of our capital expenditures; and
- changes in governmental regulations or taxation.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of standardized measure, and our financial condition and results of operations. In addition, our reserves or standardized measure may be revised downward or upward based upon production history, results of future exploitation and development activities, prevailing natural gas and oil prices and other factors. A material decline in prices paid for our production can reduce the estimated volumes of our reserves because the economic life of our wells could end sooner. Similarly, a decline in market prices for natural gas or oil may reduce our standardized measure.

Hedging transactions may limit our potential gains or cause us to lose money.

Pricing for natural gas, NGLs and oil has been volatile and unpredictable for many years. To limit exposure to changing natural gas and oil prices, we may use financial hedges and physical hedges for our production. Specifically, the First Lien Credit Facility requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017. Physical hedges are not deemed hedges for accounting purposes because they require firm delivery of natural gas and oil and are considered normal sales of natural gas and oil. We generally limit these arrangements to smaller quantities than those we project to be available at any delivery point.

In addition, we may enter into financial hedges, which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties in compliance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). The futures contracts are commitments to purchase or sell natural gas and oil at future dates and generally cover one-month periods for up to six years in the future. The over-the-counter derivative contracts are typically cash settled by determining the difference in financial value between the contract price and settlement price and do not require physical delivery of hydrocarbons.

These hedging arrangements may reduce, but will not eliminate, the potential effects of changing commodity prices on our cash flow from operations for the periods covered by these arrangements. Furthermore, while intended to help reduce the effects of volatile commodity prices, such transactions, depending on the hedging instrument used, may limit our potential gains if commodity prices were to rise substantially over the price established by the hedge. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

However, it is not always possible for us to engage in a derivative transaction that completely mitigates our exposure to commodity prices and interest rates. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices and interest rates for which we are unable to enter into a completely effective hedge transaction.

The failure by counterparties to our derivative risk management activities to perform their obligations could have a material adverse effect on our results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. If any of these counterparties were to default on its obligations under our derivative arrangements, such a default could have a material adverse effect on our results of operations, and could result in a larger percentage of our future production being subject to commodity price changes.

Regulations adopted by the Commodities Futures Trading Commission could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The ongoing implementation of derivatives legislation adopted by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Dodd-Frank Act, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission (the "CFTC"), and the SEC to promulgate rules and regulations implementing the new legislation. The CFTC finalized many of the regulations associated with the reform legislation, and is in the process of implementing position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The CFTC adopted final rules establishing margin requirements for uncleared swaps entered by swap dealers, major swap participants and financial end users (though non-financial end users are excluded from margin requirements). While, as a non-financial end user, we are not subject to margin requirements, application of these requirements to our counterparties could affect the cost and availability of swaps we use for hedging. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The new legislation and any new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was also intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and/or cash flows.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental or title and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns and increased demand on existing personnel;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers of our production; and
- the failure to realize expected growth or profitability.

Our decision to acquire oil and natural gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations. The scope and cost of the above risks may be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely affect our future growth and the ability to pay distributions.

We may be unsuccessful in integrating the operations from any future acquisitions with our operations and in realizing all of the anticipated benefits of these acquisitions.

The integration of previously independent operations can be a complex, costly and time-consuming process. The difficulties of combining these systems, as well as any operations we may acquire in the future, include, among other things:

- operating a significantly larger combined entity;
- the necessity of coordinating geographically disparate organizations, systems and facilities;

- integrating personnel with diverse business backgrounds and organizational cultures;
- consolidating operational and administrative functions;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management’s attention from other business concerns;
- customer or key employee loss from the acquired businesses;

- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Costs incurred and liabilities assumed in connection with an acquisition and increased capital expenditures and overhead costs incurred to expand our operations could harm our business or future prospects, and result in significant decreases in our gross margin and cash flows.

Our acquisitions may prove to be worth less than we paid, or provide less than anticipated proved reserves, because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and natural gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our acquisitions are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given the time constraints imposed by the applicable acquisition agreement. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor would it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

Any production associated with the assets acquired in the Rangely Acquisition will decline if the operator’s access to sufficient amounts of carbon dioxide is limited.

Production associated with the assets we acquired located in the Rangely Field in northwest Colorado (the “Rangely Acquisition”) is dependent on CO_2 tertiary recovery operations in the Rangely Field. The crude oil and NGL production from these tertiary recovery operations depends, in large part, on having access to sufficient amounts of CO_2. The ability to produce oil and NGLs from these assets would be hindered if the supply of CO_2 was limited due to, among other things, problems with the Rangely Field’s current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Any such supply limitation could have a material adverse effect on the results of operations and cash flows associated with these tertiary recovery operations. Our anticipated future crude oil and NGL production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on the operator’s ability to increase its combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within the Rangely Field.

Ownership of our oil, gas and natural gas liquids production depends on good title to our property.

Good and clear title to our oil and gas properties is important. Although we will generally conduct title reviews before the purchase of most oil, gas, natural gas liquids and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction or elimination of the revenue received by us from such properties.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition and results of operations.

We are subject to comprehensive federal, state, local and other laws and regulations that could increase the cost and alter the manner or feasibility of our doing business.

Our operations are regulated extensively at the federal, state and local levels. The regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas, NGLs and oil we may produce and sell. A major risk inherent in a drilling plan is the need to obtain drilling permits (which can include financial responsibility requirements) from state agencies and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could inhibit our ability to develop our respective properties. The natural gas, NGLs and oil regulatory environment could also change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, reduce our profitability. We may be put at a competitive disadvantage to larger companies in the industry that can spread these additional costs over a greater number of wells and these increased regulatory hurdles over a larger operating staff.

Because we handle natural gas, NGLs and oil, we may incur significant costs and liabilities in the future in order to comply with, or as a result of failing to comply with, new or existing environmental regulations or from an accidental release of substances into the environment.

How we plan, design, drill, install, operate and abandon natural gas and oil wells and associated facilities are matters subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- The federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- The federal Clean Water Act and comparable state laws and regulations that impose obligations related to spills, releases, streams, wetlands and discharges of pollutants into regulated bodies of water;
- The federal Resource Conservation and Recovery Act ("RCRA") and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities;
- The federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal; and
- Wildlife protection laws and regulations such as the Migratory Bird Treaty Act and the Endangered Species Act, which require operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days, and impose restrictions regarding the extent and timing of development, including, for example, prohibitions for tree clearing.

Complying with these environmental requirements may increase costs and prompt delays in natural gas, NGLs and oil production. It is possible that the costs and delays associated with compliance with such requirements could cause us to delay or abandon the further development of certain properties. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and remediation costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies may be enacted or adopted and could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover remediation costs, or other losses/damages, under our respective insurance policies.

We may incur costs or delays and encounter operational restrictions in connection with complying with stringent environmental regulations that apply specifically to hydraulic fracturing.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand, and chemical additives under pressure into formations to fracture the surrounding rock and stimulate production. Some of the potential effects of Federal, state, and local environmental regulation of hydraulic fracturing, including future changes in such regulation, could include the following:

- additional permitting requirements and permitting delays;
- increased costs;
- changes in the way operations, drilling and/or completion must be conducted;
- increased recordkeeping and reporting; and
- restrictions on the types of additives that can be used and locations in which we can operate.

Restrictions on hydraulic fracturing could also reduce the amount of natural gas, NGLs and oil that we are ultimately able to produce from our reserves.

State regulation of hydraulic fracturing and related development operations could result in increased costs and additional operating restrictions or delays.

The hydraulic fracturing and related development operations processes are typically regulated by state oil and natural gas commissions or by state environmental agencies. Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing and related development operations in certain circumstances. State regulation of hydraulic fracturing can take many forms. Among the forms of regulation that do, and in the future could, affect our operations or increase our costs are the following:

- Typically, states impose, by means of permits, well casing, cementing, drilling, mechanical integrity, completion, well control, and plugging and abandonment requirements to ensuring hydraulic fracturing and related development operations do not contaminate groundwater and nearby surface water.
- Most states require the disclosure of chemicals used in hydraulic fracturing fluids.
- Many states have imposed controls on the management, reuse, recycling, and disposal of hydraulic fracturing flowback fluid and production fluids.
- States limit when venting/flaring of casing head gas and gas well gas may occur.
- States may limit where fracturing can be performed and/or impose operating restrictions in certain geographic regions (i.e., location standards). For example, in areas in which there are concerns regarding induced seismicity, a state could curtail fracturing operations in the area or allow its continuance only under certain operational limitations.
- States may impose performance standards for surface activities at oil and natural gas well sites (including containment and spill response and remediation practices) and requiring operators to identify and monitor abandoned, orphaned and inactive wells prior to hydraulic fracturing.
- States may impose conditions on the disposal of drilling wastes containing naturally occurring radioactive material, as well as regulations applying to facilities that receive such wastes.
- States could even take the step of a total ban on hydraulic fracturing, as New York has done, blocking our business from that state.

Local and municipal laws could also result in increased costs and additional operating restrictions or delays.

In addition to state law, local land use restrictions, such as municipal ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing and related operations in particular. In some jurisdictions, the authority of localities to regulate hydraulic fracturing has become contentious. Courts have been asked to determine whether state regulatory schemes “pre-empt” local regulation. The outcome of legal challenges to local efforts to regulate hydraulic fracturing depends in large part on the intent of the State legislature and the comprehensiveness of its statutory scheme. If the right of municipalities to impose additional requirements is upheld, and municipalities elect to do so, local rules could impose additional constraints – such as siting and setback restrictions – and costs on our operations.

If the federal government were to comprehensively regulate hydraulic fracturing, it could impose greater costs or additional restrictions on our operations.

To date, hydraulic fracturing has not generally been subject to comprehensive regulation at the federal level. Instead, there has been limited federal regulation. For example, U.S. EPA released guidance, under its Safe Drinking Water Act underground injection control authority, regarding the use of diesel fuels in hydraulic fracturing. Implementation of the guidance will largely occur through State permitting programs. As another example, the Department of Interior's Bureau of Land Management had issued regulations governing the conduct of hydraulic fracturing federal and Indian lands, but, on June 21, 2016, a Wyoming federal district judge invalidated the rules on the basis that Congress had not given the Department authority to regulate in this manner. The Federal government appealed the decision to the 10th Circuit Court of Appeals on June 24, 2016, and the litigation is ongoing. On-going federal agency environmental reviews of hydraulic fracturing could, however, result in additional regulation. Or Congress could adopt new laws affecting our operations or directing a federal agency to regulate our operations in new or additional ways. Any such development on the federal level could make it more difficult or costly for us to perform hydraulic fracturing to stimulate production from dense subsurface rock formations.

Our drilling and production operations require both adequate sources of water to facilitate the fracturing process and the disposal of flowback and produced fluids. If we are unable to dispose of the flowback and produced fluids at a reasonable cost and in compliance with applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

A significant portion of our natural gas, NGLs and oil extraction activities utilize hydraulic fracturing, which results in water that must be treated and disposed of in accordance with applicable regulatory requirements. Environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. Our ability to collect and dispose of flowback and produced fluids will affect our production, and potential increases in the cost of wastewater treatment, handling, and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of wastewater, drilling fluids and other substances associated with the exploration, development and production of natural gas, NGLs and oil.

Rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In 2012, USEPA established the NSPS rule for oil and natural gas production, transmission, and distribution, and also made significant revisions to the existing National Emission Standards for Hazardous Air Pollutants ("NESHAP") rules for oil and natural gas production, transmission, and storage facilities. These rules require oil and natural gas production facilities to conduct "green completions" for hydraulic fracturing, which is recovering rather than venting the gas and natural gas liquids that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Both the NSPS and NESHAP rules continue to evolve based on new information and changing environmental concerns. President Trump's March 28, 2017, Executive Order on Promoting Energy Independence and Economic Growth ordered federal agencies to revisit federal rules aimed at limiting methane emissions from oil and gas wells. We believe it will be several years before those new rules are fully implemented.

States are also proposing increasingly stringent requirements for air pollution control and permitting for well sites and compressor stations. For example, in January 2016, the Governor of Pennsylvania announced a comprehensive new regulatory strategy for reducing methane emissions from new and existing oil and natural gas operations, including well sites, compressor stations, and pipelines. Implementation of this strategy will result in significant changes to the air permitting and pollution control standards that apply to the oil and gas industry in Pennsylvania. It may also influence air programs in other oil and gas-producing states. Moreover, West Virginia issued General Permit 70-A for natural gas production facilities at the well site in 2013. In response to industry concerns regarding the restrictiveness of the general permit, in November 2015, West Virginia issued General Permit 70-B which provides more flexibility for emission sources located at the well site.

Compliance with new rules regulating air emissions from our operations could result in significant costs, including increased capital expenditures and operating costs, and could affect the results of our business.

Climate change laws and regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations.

With the issuance, on March 28, 2017, of President Trump's Executive Order on Promoting Energy Independence and Economic Growth, we believe it may take many years for new comprehensive federal policy aimed at greenhouse gas emissions to gel (see "Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change"). Given the Supreme Court's decision in Massachusetts v. EPA, 549 U.S. 497 (2007) (holding that greenhouse gases are "air pollutants" covered by the Clean Air Act) and scientific hurdles to overturning EPA's endangerment finding, we believe the new Administration will have to pursue some form of regulation. Regulations with the most direct impact our operations concern controlling methane emissions from wells. Rules that affect overall consumption of fossil fuels, and the mix of fossil fuels consumed, could also affect the demand for our products. We believe, however, that federal agency implementation of the President's Executive Order is some years away. While Congress has from time to time considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. Reports of greater Congressional activity with respect to greenhouse gas emissions are scarce.

In the absence of comprehensive federal climate change policy, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs that typically require major sources of greenhouse gas emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those greenhouse gases. States may also pursue additional regulation of our operations, including restrictions on methane emissions from new and existing wells and fracturing operations. State and regional initiatives could result in significant costs, including increased capital expenditures and operating costs, affect the demand for our products, and could affect the results of their business.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

If fully implemented, environmental policies the new President supported during his campaign could increase supply in the overall markets for fuels, thereby potentially reducing prices for the Company's output.

During the election campaign, President Trump pledged to implement policies that would reinvigorate coal's use for energy production and ease restrictions on production and transportation of petroleum. If fully implemented, these policies could have the effect of increasing the overall fuel supply, thereby reducing prices for the Company's output. For example, President Trump pledged to reverse the prior Administration's policies that disadvantaged coal as a fuel for energy production. President Trump promised to take several actions to encourage burning coal for energy production and lessen the financial burden of environmental regulations on coal-fired plants' operations. The President pledged to withdraw from the Paris Climate Agreement, withdraw or re-write the Clean Power Plan, withdraw mercury limits on coal plants' air emissions, lift the prior Administration's ban on new coal leases on federal lands and end the review of the program's greenhouse gas impacts, and withdraw the "Waters of the United States" stream protection rule. The new Administration has taken this final action. President Trump also indicated his Administration would open more federal lands for oil and gas production, approve the construction of the Keystone Pipeline to facilitate refining of Alberta oil shale in the U.S., license the Dakota Access Pipeline, and open areas in the Arctic and Atlantic Ocean to drilling. If fully implemented, these policies would increase the overall fuel supply and could have the effect of diminishing demand for the Company's natural gas output. Diminished demand could put additional downward pressure on the price of the natural gas the Company produces.

Impact fees and severance taxes could materially increase our liabilities.

In an effort to offset budget deficits and fund state programs, many states have imposed impact fees and/or severance taxes on the natural gas industry. In February 2012, the Commonwealth of Pennsylvania enacted an "impact fee" on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year a well is spudded and varies, like most severance taxes, based upon natural gas prices. As of December 31, 2016, the impact fee for our wells, including the wells in our Drilling Partnerships, was approximately $0.7 million.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

A cyber incident or a terrorist attacks could result in information theft, data corruption, operational disruption and/or financial loss.

We have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future cyber or terrorist attacks than other targets in the United States. Deliberate attacks on, or security breaches in our systems or infrastructure, or the systems or infrastructure of third parties or the cloud, could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, challenges in maintaining our books and records and other operational disruptions and third party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Relating to Our Common Shares

If prices of our Common Shares decline, our shareholders could lose a significant part of their investment.

The market price of our Common Shares could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts’ recommendations and their estimates of our financial performance;
- the public’s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies;
- fluctuations in natural gas and oil prices;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our cash distributions;
- future issuances and sales of our securities; and
- changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our Common Shares.

The trading price of our Common Shares may be volatile, with the result that an investor may not be able to sell any shares acquired at a price equal to or greater than the price paid by the investor.

Our Common Shares are quoted on the OTCQX Market under the symbol “TTEN.” These markets are relatively unorganized, inter-dealer, over-the-counter markets that provide significantly less liquidity than the NASDAQ or the

NYSE. Although we will use our commercially reasonable efforts to list our Common Shares on the NYSE (or other national securities exchange approved by our Board as soon as practicable after the applicable listing standards are satisfied or have been waived, no assurances can be given that our Common Shares can be listed on the NYSE (or other national securities exchange). In this event, there would be a highly illiquid market for our Common Shares and you may be unable to dispose of your Common Shares at desirable prices or at all.

Sales of our Common Shares may cause our share price to decline.

Sales of substantial amounts of our Common Shares in the public market, or the perception that these sales may occur, could cause the market price of our shares to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional shares. In connection with our actions to address our liquidity concerns, we may sell a substantial number of Common Shares, which would result in significant dilution.

Certain shareholders have significant influence over us and their interests might conflict with or differ from your interests as a shareholder.

Holders of our Predecessor's senior notes, in exchange for their claims to the notes, acquired a significant ownership interest in the Common Shares pursuant to the Plan. Our Second Lien Lenders also received a significant ownership interest in our Common Shares. If such holders were to act as a group, such holders would be in a position to control the outcome of certain actions requiring shareholder approval, including the election of directors, without the approval of other shareholders. This concentration of ownership could also facilitate or hinder a negotiated change of control of the Company and, consequently, have an impact upon the value of the Common Shares.

Provisions in our LLC Agreement limit the rights of our shareholders to elect our directors, which limits their ability to influence us or affect our management.

Pursuant to our LLC Agreement, only our Class B directors are elected by the holders of our Common Shares. Further, we are not required to hold an annual meeting for the election of those Class B directors until 2019. In addition, holders of our Predecessor's senior notes and our Second Lien Lenders designated our Class B directors, and are entitled to nominate Class B directors for election beginning in 2019. Beginning in 2019, only shareholders, or a group of shareholders, who own at least 10% of our outstanding Common Shares may nominate a Class B director for election. Accordingly, holders of Common Shares will have no ability to replace members of the Board prior to 2019 and only limited ability to do so thereafter.

We currently do not intend to pay distributions on our Common Shares, and the First Lien Credit Facility and the Second Lien Credit Facility place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Common Shares appreciates.

We do not plan to pay distributions on our Common Shares in the foreseeable future. Additionally, the First Lien Credit Facility and the Second Lien Credit Facility place certain restrictions on our ability to pay cash distributions. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your Common Shares at a price greater than you paid for it. There is no guarantee that the price of our Common Shares that will prevail in the market will ever exceed the price at which you purchase Common Shares.

We may issue an unlimited number of additional securities, including securities that are senior to the Common Shares, without shareholder approval, which would dilute shareholders' ownership interests.

Our amended and restated limited liability company agreement (our "LLC Agreement") does not limit the number of additional company securities that we may issue at any time without the approval of our shareholders. In addition, we may issue an unlimited number of securities that are senior to the Common Shares in right of distribution, liquidation and voting, without the approval of our shareholders.

Shareholders may have liability to repay distributions that were wrongfully distributed to them, or other liabilities with respect to ownership of our Common Shares.