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, 2017

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: 00055840

DGOC SERIES 18(C), L.P.
(Exact name of registrant as specified in its charter)

Delaware	**82-2114425**
(State or other jurisdiction or incorporation or organization)	**(I.R.S. Employer Identification No.)**
1100 Corporate Drive Birmingham AL	**35242**
(Address of principal executive offices)	**Zip code**

Registrant's telephone number, including area code: (412) 489-0006

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

Title of each class	Name of each exchange on which registered
None	None

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

Common Units representing Limited Partnership Interests
(Title of Class)

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 the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ 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 ☒

DOCUMENTS INCORPORATED BY REFERENCE: None

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GLOSSARY OF TERMS

Key Term	**Definition**
Bbl	One barrel of crude oil, condensate, or other liquid hydrocarbons equal to 42 United States gallons.
Bpd	Barrels per day.
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.
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.
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	The total acres or wells, as the case may be, in which a working interest is owned.
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	One thousand cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or natural gas liquids.
Mcfd	One thousand cubic feet per day.
Mcfed	One Mcfe 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.
Productive well	A producing well or a 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.

Key Term	**Definition**
Proved reserves	Proved gas and oil reserves are those quantities of gas and oil, 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".
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).

Key Term	**Definition**
Reservoir	A porous and permeable underground formation containing a natural accumulation of economically productive oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.
SEC	Securities Exchange Commission.
Standardized Measure	Standardized measure, or standardized measure of discounted future net cash flows relating to proved gas and oil 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 gas and/or oil in commercial quantities.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of gas and oil 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

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-K or to reflect the occurrence of unanticipated events. The following 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:

- *the demand for natural gas, oil, NGLs and condensate;*
- *the price volatility of natural gas, oil, NGLs and condensate;*
- *changes in the differential between benchmark prices for oil and natural gas and wellhead prices that we receive;*
- *future financial and operating results;*
- *resource potential;*
- *economic conditions and instability in the financial markets;*
- *the accuracy of estimated natural gas and oil reserves;*
- *the financial and accounting impact of hedging transactions;*
- *the limited payment of distributions, or failure to declare a distribution;*
- *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;*
- *changes and potential changes in the regulatory and enforcement environment in the areas in which we conduct business;*
- *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;*
- *potential incurrence of significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment;*
- *uncertainties with respect to the success of drilling wells at identified drilling locations;*
- *uncertainty regarding leasing operating expenses, general and administrative expenses and funding and development costs;*
- *exposure to financial and other liabilities of the managing general partner;*
- *the ability to comply with, and the potential costs of compliance with, new and existing federal, state, local and other laws and regulations applicable to our business and operations;*
- *restrictions on hydraulic fracturing;*
- *exposure to new and existing litigation;*
- *development of alternative energy resources; and*
- *the effects of a cyber-event or terrorist attack.*

The Partnership cautions you that the forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in this report. Should one or more of the risks or uncertainties described above occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

PART I

ITEM 1: BUSINESS

Overview

DGOC Series 18(C), L.P. (the "Partnership") is a Delaware limited partnership, formed on July 6, 2017 and includes the Appalachian-based assets that were previously included within, Atlas Resources Public 18-2009(C), L.P. ("Predecessor Partnership") that was formed on June 9, 2009 and was then managed by Atlas Resources, LLC ("Atlas" or "Previous MGP"). DGOC Partnership Holdings, LLC now serves as the Partnership's Managing General Partner (“DGOC Holdings” or the “MGP”) and certain affiliates of the MGP serve as our Operator ("Operator"). DGOC Holdings is an indirect subsidiary of Diversified Gas & Oil, PLC (“Diversified”; AIM: DGOC). Unless the context otherwise requires, references below to “the Partnership,” “we,” “us,” “our” and “our company”, refer to DGOC Series 18(C), L.P.

Atlas previously served as the Partnership's Managing General Partner and Operator . Atlas is an indirect subsidiary of Titan Energy, LLC (“Titan”). On May 4, 2017, Titan entered into a definitive agreement to sell, among other conventional assets, its general and limited partnership equity interest (“Equity Interest”) in the Partnership to Diversified (the “Purchase and Sale Agreement” or “PSA”). The transaction was subject to customary closing conditions, had an effective date of April 1, 2017 and closed on September 29, 2017. Prior to closing the PSA, the Previous MGP delegated operational activities to an affiliate of Diversified for the Partnership’s natural gas wells in Pennsylvania and Tennessee on June 30, 2017. Upon closing the PSA, the Previous MGP’s Equity Interest in the Partnership was transferred to DGOC Holdings and DGOC Holdings was admitted as a substitute managing general partner of the Partnership and continues to serve as Operator.

For additional information, see Part II, Item 8, Note 1.

Historical Drilling Activity

During 2009 and 2010, we drilled 81 gross wells, 71.68 net wells, within the Marcellus Shale and Southern Appalachia Shale geological formations in Pennsylvania and Tennessee. We intend to produce our wells until they are depleted or become uneconomical to produce, at which time they will be plugged and abandoned or sold. No other wells will be drilled and no additional funds will be required for drilling.

Natural Gas Production

Production Revenues, Volumes, Prices and Costs

The MGP markets the majority of our natural gas production to natural gas marketers directly or to third-party plant operators who process and market the natural gas. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index.

Our production revenues and estimated natural gas reserves are substantially dependent on prevailing market prices for natural gas. The following table presents our production revenues, volumes and average sales prices for our natural gas production for the periods indicated, along with our average production costs in each of the reported periods:

	Years Ended December 31,			
	2017	**2016**	**$ Change**	**% Change**
Production revenues (in thousands):				
Natural gas revenue	$ 6,520	$ 4,465	2,055	46 %
Production:				
Natural gas (Mcf)	2,622,504	3,205,770	(583,266)	(18)%
Average sales price:				
Natural gas (per Mcf)	$ 2.49	$ 1.39	1.10	79 %
Production costs (per Mcfe)	$ 0.82	$ 0.62	0.20	32 %

Our ongoing operating and maintenance costs have been or are expected to be fulfilled through revenues from the sale of our natural gas production and through the subsidization of our MGP. Our MGP charges a monthly well supervision fee of $975 per well per month for the Marcellus Shale wells and for all other wells a fee of $392 is charged per well per month as outlined in our drilling and operating agreement. This well supervision fee covers all normal and regularly recurring operating expenses for the production and sale of natural gas such as:

- Well tending, routing maintenance and adjustment;
- Reading meters, recording production, pumping, maintaining appropriate books and records; and
- Preparation of reports for us and government agencies.

The well supervision fees, however, do not include costs and expenses related to the purchase of certain equipment and materials and brine disposal. If these expenses are incurred, we are charged the costs for third-party services, materials, and a competitive charge for services performed directly by our MGP or its affiliates. Also, beginning one year after each of our wells has been placed into production, our MGP, as operator, may retain $200 per month per well to cover the estimated future plugging and abandonment cost of the well. As of December 31, 2017, our MGP and the Previous MGP withheld $317,800 of net production revenue for this purpose. For additional information, see Part II, Item 8, Note 1.

Contractual Revenue Arrangements

We have no delivery commitments for fixed and determinable quantities of natural gas in any future periods under existing contracts or agreements.

Natural Gas. The MGP markets the majority of our natural gas production to gas purchasers directly or to third-party midstream companies who gather, treat and process, as necessary, and market 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 include:

- Dominion South Point
- Tetco M2

The following table summarizes our customers accounting for at least 10% of total natural gas production revenues for the year ended December 31, 2017:

Direct Energy Business LLC	73%
Dominion Field Services, Inc.	11%
Other (no single customer accounts for more than 10% of revenues)	16%
Total	100%

Natural Gas Gathering Agreements

Substantially all natural gas produced is gathered through one or more pipeline systems before sale or delivery to a purchaser or an interstate pipeline. Each separate company providing gathering services charges a gathering fee for each gathering activity provided. Fees will vary depending on the distance the gas travels and whether additional services such as compression, blending, or treating are provided.

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. For its services, Laurel Mountain charges the greater of $0.35 per mcf or 16% of the gross sales price of the natural gas, though it does charge a lesser fee to a small number of specific wells in the area.

Competition and Markets

We operate entirely within the Appalachian Basin of the United States. The natural gas industry is affected by many factors that we cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on our operations and profitability. The impact of these factors is extremely difficult to accurately predict or anticipate. It is difficult for us to predict the occurrence of events that may affect commodity prices or the degree to which these prices will be affected; however, the prices we receive for the commodities we produce will generally approximate current market prices in the geographic region of the production.

Natural gas prices are primarily determined by North American supply and demand and to a lesser extent, natural gas exports and are heavily influenced by weather and storage levels. Natural gas prices may continue to be under pressure largely due to excess supply of natural gas caused by the high productivity of shale plays in the United States which has outpaced demand. Depressed natural gas futures prices reflect the expectation there will be an oversupply of natural gas in the future.

Natural gas prices affect:

- our revenues, profitability and cash flow;
- the quantity of natural gas that we can economically produce; and
- the quantity of natural gas shown as proved reserves.

Any continued or extended decline in natural gas prices could have a material adverse effect on our financial position, results of operations, and cash flows.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the spring and fall months and increases during the winter months and, in some areas, also increases during the summer months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand.

Environmental Matters and Regulation

Our operations are subject to numerous federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may include but are not limited to:

- the acquisition of a permit before construction commences;
- restriction of the types, quantities and concentrations of various substances that can be released into the environment in connection with production and transporting through pipelines;
- governing the sourcing and disposal of water used in the drilling and completion process;
- requiring some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments; and
- imposing substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings.

These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the natural gas industry in general.

Natural gas activities have increasingly faced opposition from environmental organizations and, in certain areas, have been, restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liability 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, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA. In addition, certain state laws also regulate the disposal of oil and natural gas wastes. New state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

Waste handling. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry. Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for many years for the exploration and production of natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

Water discharges and use. The Federal Water Pollution Control Act, as amended (the "CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

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 an oil 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 substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Underground Injection Control ("UIC") Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. In connection with our operations, the Partnership may dispose of produced water in underground wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. However, because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. For example, in January 2016, Ohio lawmakers proposed new legislation that would, among other things, require injection wells be located more than 2,000 feet from any occupied dwelling. While that particular legislation did not become law, should similar onerous regulations or bans relating to underground wells be placed in effect in areas where the Partnership has significant operations, there could be an impact on the Partnership's ability to operate.

Hydraulic fracturing. Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice to stimulate production of natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state environmental agencies and oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act (as defined below) regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, while the Federal Bureau of Land Management ("BLM") released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands in March 2015, on December 29, 2017, the U.S. Department of Interior rescinded the 2015 rule that would have set new environmental limitations on hydraulic fracturing, or fracking, on public lands because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania and Texas, have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing operations. States could also elect to prohibit hydraulic fracturing altogether, such as in the State of New York. Local governments also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA issued its final report on the potential of hydraulic fracturing to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases, and inadequate treatment and discharge of wastewater which did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. However, the EPA's report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing to impact drinking water resources, including ground water and surface water monitoring in areas with hydraulically fractured oil and gas production wells. Based on the EPA's study, existing regulations and our practices, we do not believe our hydraulic fracturing operations are likely to impact drinking water resources but the EPA study could result in initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our hydraulic fracturing operations have not resulted in material environmental liabilities. We do not maintain insurance policies intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover any alleged third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Air emissions. The Clean Air Act of 1963 (as amended, the "Clean Air Act"), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, pursuant to then President Obama's Strategy to Reduce Methane Emissions in August 2015, the EPA proposed new regulations that would set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA finalized these new regulations on June 3, 2016 to be effective August 2, 2016; however on June 12, 2017 the EPA announced a proposed 2 year stay on these fugitive emissions standards "while the agency reconsiders them". Therefore, the date when and if these standards may become implemented is still not known. In a second example, in October 2015, the EPA finalized a rulemaking proposal that revises the National Ambient Air Quality Standard for ozone to 70 parts per billion for both the 8-hour primary and secondary standards. Compliance with one or both of these regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We believe that our monitoring activities and reporting are in substantial compliance with applicable obligations.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years, such as the establishing of Title V and PSD permitting reviews for GHG emissions as described in more detail above. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal or state laws and regulations, or international compacts, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. On an international level, the United States was one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, which agreement formally entered into force on November 4, 2016. While the United States formally accepted that agreement in September 2016, on June 1, 2017, President Trump determined to withdraw the United States from the Paris Agreement. Under the term of the Paris Agreement, the earliest possible effective date for withdrawal by the United States is November 4, 2020, four years after the agreement came into effect. Future United States regulations on GHG emissions designed to meet the Paris Agreement goals could impact us in ways that cannot be determined at this time.

While it is unclear at this time whether President Trump or Congress will pursue legislation or regulation to address GHG emissions in light of the withdrawal of the Paris Agreement, any such legislation or regulatory programs could also increase the cost of consuming, and thereby could reduce demand for the oil and natural gas that we produce. However, President Trump has taken certain actions since taking office that have begun to establish a national policy in favor of energy independence and economic growth. For example, on March 28, 2017, President Trump issued an Executive Order for the purpose of facilitating the development of United States energy resources and reducing unnecessary regulatory burdens associated with the development of those resources. Through the Executive Order, President Trump has directed agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise, or rescind regulations that unduly burden the development of United States energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Endangered species. The federal Endangered Species Act of 1973, as amended (the "ESA"), restricts activities that may affect endangered and threatened species or their habitats. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, or are located in an area where new pipelines are planned; the work could be prohibited or delayed or expensive mitigation may be required. Moreover, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. As a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") was required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act prior to the completion of the agency's 2017 fiscal year. For example, while the lesser prairie chicken is not currently designated as threatened or endangered, in November 2016, the FWS issued its 90-day findings in response to a petition to reclassify the lesser prairie chicken under the ESA. In those findings, FWS found that the petition presented substantial information that the petitioned action may be warranted, prompting a thorough status review. We cannot predict the outcome of this review process. The designation of currently unprotected species, including the lesser prairie chicken, as threatened or endangered in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

The Migratory Bird Treaty Act (“MBTA”) implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations, we may be required to obtain necessary permits to conduct those operations, which may result in specified operating restrictions on a temporary, seasonal, or permanent basis in affected areas and an adverse impact on our ability to develop and produce our reserves. However, in December 2017, the U.S. Department of Interior stated in a solicitor’s opinion that it will no longer prosecute oil and gas, wind and solar operators that accidentally kill birds based on a reinterpretation of the MBTA that it does not prohibit accidental takings of migratory birds.

We believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2017, nor do we anticipate that such expenditures will be material in 2018. However, we regularly have expenditures to comply with environmental laws and we anticipate those costs will continue to be incurred in the future.

Employees

We do not directly employ any of the persons responsible for our management or operation. Rather, through December 31, 2017 our Former MGP employed the personnel necessary to manage and operated our business through a Transition Services Agreement ("TSA"). Beginning January 1, 2018 and following the expiration of the TSA, our MGP employs the personnel needed to manage and operate our wells.

Available Information

We make our periodic reports under the Securities Exchange Act of 1934, 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 MGP’s website at www.diversifiedgasandoil.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (“SEC”). You may also receive, without charge, a paper copy of any such filings by request to us at PO Box 381087, Birmingham, AL 35238, telephone number (844) 378-1168. 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 Securities and Exchange Commission’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 2: PROPERTIES

Natural Gas Reserves

For additional information, see Part II, Item 8, Note 8.

Productive Wells

Productive wells consist of producing wells and wells capable of production. The following table sets forth information regarding productive natural gas wells in which we have a working interest as of December 31, 2017:

	Number of productive wells	
	Gross	**Net**
Wells drilled at inception	81.00	71.68
Less:		
Dry holes	—	—
Plugged and abandoned	—	—
Sold	1.00	1.00
Productive natural gas wells	80.00	70.68

Developed Acreage

The following table sets forth information about our developed natural gas acreage as of December 31, 2017:

	Developed Acreage	
	Gross	Net
Pennsylvania	1,738	1,547
Tennessee	698	669
Total	2,436	2,216

The leases for our developed acreage generally have terms that extend for the life of the wells. We believe that we hold good and indefeasible title to our producing properties, in accordance with standards generally accepted in the natural gas industry, subject to exceptions stated in the opinions of counsel employed by us in the various areas in which we conduct our activities. We do not believe that these exceptions detract substantially from our use of any property. As is customary in the natural gas industry, we conduct only a perfunctory title examination at the time we acquire a property. Before we commenced drilling operations, we conducted an extensive title examination and we performed curative work on defects that we deemed significant. We or our predecessors obtained title examinations for substantially all of our managed producing properties. No single property represents a material portion of our holdings.

Our properties are subject to royalty, overriding royalty and other outstanding interests customary in the industry. Our properties are also subject to burdens such as liens incident to operating agreements, taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. We do not believe that any of these burdens materially interfere with our use of our properties.

ITEM 3: LEGAL PROCEEDINGS

From time to time, we may be party to various routine legal proceedings arising out of the ordinary course of our business. Our MGP believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations. As of December 31, 2017, there were no outstanding legal proceedings.

For additional information, see Part II, Item 8, Note 7.

ITEM 4: MINE SAFETY DISCLOSURES (Not applicable)

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

There is no established public trading market for our units, and we do not anticipate that a market for our units will develop. Our units may be transferred only in accordance with the provisions of Article VI of our partnership agreement which requires:

- our MGP's consent;
- the transfer not result in materially adverse tax consequences to us; and
- the transfer does not violate federal or state securities laws.

An assignee of a unit may become a substituted partner only upon meeting the following conditions:

- the assignor gives the assignee the right;
- our MGP consents to the substitution
- the assignee pays to us all costs and expenses incurred in connection with the substitution; and
- the assignee executes and delivers the instruments, which our MGP requires to effect the substitution and to confirm his or her agreement to be bound by the term of our partnership agreement.

A substitute partner is entitled to all of the rights of full ownership of the assigned units, including the right to vote. As of December 31, 2017, we had 4,979 limited partners.

Our MGP reviews our accounts monthly to determine whether cash distributions are appropriate and the amount to be distributed, if any. We distribute any funds which our MGP determines are not necessary for us to retain. We will not advance or borrow funds for purposes of making distributions. During the years ended December 31, 2017 and 2016, we distributed the following:

	Distributions	
	2017	2016
Limited Partners	$ 3,023,200	$ (2,594,100)
Managing General Partner	1,132,200	(587,400)
Total distributions	$ 4,155,400	$ (3,181,500)

ITEM 7: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The discussion and analysis presented below provides information to assist in understanding our financial condition and results of operations. You should read this in conjunction with Item 8,which contains our financial statements and notes thereto. Our operating cash flows are generated from the sale of our wells' production, which produce natural gas. We deliver our produced natural gas to market through affiliated and/or third-party gas gathering systems.

Our ongoing operating and maintenance costs are fulfilled through revenues from the sale of our natural gas production and through subsidies provided by our MGP. Our results of operations are dependent upon the difference between prices received for our natural gas production and the costs to find and produce such natural gas. Natural gas prices have been volatile and subject to fluctuations based on a number of factors beyond our control. We currently have no derivative contracts to hedge against declines in commodity prices, and we do not expect to hedge in the future.

RESULTS OF OPERATIONS

The following table sets forth information related to our production revenues, volumes, sales prices, production costs and depletion during the periods indicated:

	Years Ended December 31, 2017	Years Ended December 31, 2016	$ Change	% Change
Production revenues (in thousands):				
Natural gas	$ 6,520	$ 4,465	2,055	46 %
Production volumes:				
Natural gas (Mcf/day)	7,185	8,759	(1,574)	(18)%
Average sales price:				
Natural gas (per mcf)	$ 2.49	$ 1.39	1.10	79 %
Production costs:				
Production costs (in thousands)	2,138	1,973	165	8 %
As a percent of revenues	33%	44%	(11)%	(25)%
Per mcfe	$ 0.82	$ 0.62	0.20	32 %
Depletion per mcfe	$ 0.79	$ 0.79	—	— %

Revenues *(in thousands)*

The following table reconciles the changes in natural gas revenues, in thousands, for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

	Total
Natural gas revenues for the year ended December 31, 2016	$ 4,465
Volume decrease	(812)
Price increase	2,867
Net increase	2,055
Natural gas revenues for the year ended December 31, 2017	$ 6,520

The natural gas volume variances reflected for the periods presented in the tables above relate to:

- wells being temporarily shut-in;
- timing differences associated with the production from those wells depending upon when they are placed back into production; and
- normal and expected declines inherent in the life of a well.

Costs and Expenses *(in thousands)*

	Years Ended December 31, 2017	Years Ended December 31, 2016	$ Change	% Change
Production	$ 2,138	$ 1,973	165	8 %
Depletion	2,081	2,537	(456)	(18)%
Impairment	35	—	35	100 %
Accretion of asset retirement obligations	131	125	6	5 %
General and administrative	132	135	(3)	(2)%
Total costs and expenses	$ 4,517	$ 4,770	(253)	(5)%

Production expenses increased $165 (8%). This increase was primarily due to an increase in transportation expenses as a result of an increase in natural gas prices offset by a decrease in water hauling and supervision fees, which is a result of the cost reduction initiatives of the MGP.

Depletion expense moved proportionately to the corresponding 18% decline in produced volumes.

Impairment of gas and oil properties was $35 for the year ended December 31, 2017. The impairment was due to the deterioration of salvage values. At least annually, we compare the carrying value of our proved developed gas and oil producing properties to their estimated fair market value.

General and administrative expenses were relatively flat.

Liquidity *(in thousands)*

Cash flows from operating activities were $3,906 and $3,248 for the years ended December 31, 2017 and 2016, respectively and include cash receipts and disbursements attributable to our normal monthly operating cycle for natural gas production, lease operating expenses, gathering, processing and transportation expense, severance taxes, general and administrative expenses. The increase in cash flows resulted primarily from increased revenues driven by higher realized natural gas prices offset by lower volumes.

We had no net cash flows from investing activities for the year ended December 31, 2017. Cash provided by investing activities was $12 for the year ended December 31, 2016 and was related to proceeds received from the sale of tangible equipment.

Cash used in financing activities increased $974 to $4,155 for the year ended December 31, 2017 from $3,181 for the year ended December 31, 2016. This increase was due to an increase in cash distributions to partners, which was driven by a 46% increase in revenues and a 5% decrease in costs and expenses.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires that we make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depletion and amortization, and impairment. We summarize our significant accounting policies within our financial statements (See Part II, Item 8, Note 1) included in this report. Our identified critical accounting policies and estimates are discussed below.

Depletion and Impairment of Long-Lived Assets

Long-Lived Assets. The cost of natural gas properties, less estimated salvage value, is generally depleted on the units-of-production method.

We review natural gas properties for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset is considered to be impaired when the undiscounted net cash flows expected to be generated by the asset are less than its carrying amount. The undiscounted net cash flows expected to be generated by the asset are based upon our estimates that rely on various assumptions, including natural gas prices, production and operating expenses. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. Recent increases in natural gas drilling have driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas prices may result in additional impairment charges in future periods.

Events or changes in circumstances that would indicate the need for impairment testing include, among other factors:

- operating losses;
- unused capacity;
- market value declines;
- technological developments resulting in obsolescence;
- changes in demand for products manufactured by others utilizing our services or for our products;
- changes in competition and competitive practices;
- uncertainties associated with the United States and world economies;
- changes in the expected level of environmental capital, operating or remediation expenditures; and
- changes in governmental regulations or actions.

As a result of the significant declines in commodity prices and associated historical recorded impairment charges, remaining net book value of natural gas properties on our balance sheets at December 31, 2017 and 2016 was primarily related to the estimated salvage value of such properties. The estimated salvage values were based on our MGP's historical experience in determining such values and were discounted based on the remaining lives of those wells using an assumed credit adjusted risk-free interest rate. For additional information see Part II, Item 8, Notes 1 and 3.

Reserve Estimates

Our reserve analysis is based upon various assumptions, including those required by the SEC, as to natural gas prices, drilling and operating expenses, capital expenditures and availability of funds. The accuracy of these reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. We engaged Wright & Company, Inc., our MGP's independent, third-party reserve engineer, to prepare a report of our proved reserves. For additional information see Part II, Item 8, Note 8.

Asset Retirement Obligations

We estimate the liability for the plugging and abandonment of our natural gas wells based on our historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The associated asset retirement costs are capitalized as part of the carrying amount of the long lived asset. The liability is discounted using our MGP's assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our natural gas properties, we believe that there are no other material retirement obligations associated with tangible long lived assets. For additional information see Part II, Item 8, Notes 1 and 4.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
DGOC Series 18(C), L.P.

Opinion on the financial statements

We have audited the accompanying balance sheets of DGOC Series 18(C), L.P. (a Delaware Limited Partnership) (the "Partnership") as of December 31, 2017 and 2016, the related statements of operations, comprehensive income (loss), changes in partners' capital, and cash flows for each of the two years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2017.

Cleveland, Ohio
March 28, 2018

DGOC SERIES 18(C), L.P.
BALANCE SHEETS
DECEMBER 31, 2017 AND 2016

	2017	2016
ASSETS		
Current assets:		
Cash	$ —	$ 249,000
Accounts receivable trade-affiliate	1,325,700	1,139,500
Total current assets	1,325,700	1,388,500
Gas and oil properties, net	28,788,400	30,904,400
Long-term asset retirement receivable-affiliate	317,800	170,700
Total assets	$ 30,431,900	$ 32,463,600
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accrued liabilities	$ 28,900	$ 39,700
Total current liabilities	28,900	39,700
Asset retirement obligations	2,773,200	2,641,800
Total long-term liabilities	2,773,200	2,641,800
Total liabilities	2,802,100	2,681,500
Commitments and contingencies (Note 7)		
Partners' capital:		
Managing general partner's interest	2,426,400	2,613,200
Limited partners' interest (22,928.90 units)	25,203,400	27,168,900
Total partners' capital	27,629,800	29,782,100
Total liabilities and partners' capital	$ 30,431,900	$ 32,463,600

See accompanying notes to financial statements.

DGOC SERIES 18(C), L.P.
STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2017 AND 2016

	2017	2016
REVENUES		
Natural gas	$ 6,519,800	$ 4,464,800
Gain on mark-to-market derivatives	—	18,500
Total revenues	6,519,800	4,483,300
COSTS AND EXPENSES		
Production	2,137,600	1,973,300
Depletion	2,080,600	2,537,200
Impairment	35,400	—
Accretion of asset retirement obligations	131,400	124,900
General and administrative	131,700	134,500
Total costs and expenses	4,516,700	4,769,900
Net income (loss)	$ 2,003,100	$ (286,600)
Allocation of net income (loss):		
Managing general partner	$ 945,400	$ 435,400
Limited partners	$ 1,057,700	$ (722,000)
Net income (loss) per limited partnership unit	$ 46	$ (31)

See accompanying notes to financial statements.

DGOC SERIES 18(C), L.P.
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
YEARS ENDED DECEMBER 31, 2017 AND 2016

	2017	2016
Net income (loss)	$ 2,003,100	$ (286,600)
Difference in estimated hedge gains receivable	—	223,100
Reclassification adjustment to net loss of mark-to-market gains on cash flow hedges	—	(223,800)
Total other comprehensive loss	—	(700)
Comprehensive income (loss)	$ 2,003,100	$ (287,300)

See accompanying notes to financial statements.

DGOC SERIES 18(C), L.P.
STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
YEARS ENDED DECEMBER 31, 2017 AND 2016

	Managing General Partner	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2015	$ 2,765,200	$ 30,485,000	$ 700	$ 33,250,900
Participation in revenues and costs and expenses:				
Net production revenues	726,700	1,764,800	—	2,491,500
Gain on mark-to-market derivatives	—	18,500	—	18,500
Depletion	(218,700)	(2,318,500)	—	(2,537,200)
Impairment	—	—	—	—
Accretion of asset retirement obligations	(35,100)	(89,800)	—	(124,900)
General and administrative	(37,500)	(97,000)	—	(134,500)
Net income (loss)	435,400	(722,000)	—	(286,600)
Other comprehensive loss	—	—	(700)	(700)
Distributions to partners	(587,400)	(2,594,100)	—	(3,181,500)
Balance at December 31, 2016	2,613,200	27,168,900	—	29,782,100
Participation in revenues and costs and expenses:				
Net production revenues	1,225,000	3,157,200	—	4,382,200
Depletion	(190,600)	(1,890,000)	—	(2,080,600)
Impairment	(15,500)	(19,900)	—	(35,400)
Accretion of asset retirement obligations	(36,700)	(94,700)	—	(131,400)
General and administrative	(36,800)	(94,900)	—	(131,700)
Net income loss	945,400	1,057,700	—	2,003,100
Distributions to partners	(1,132,200)	(3,023,200)	—	(4,155,400)
Balance at December 31, 2017	$ 2,426,400	$ 25,203,400	$ —	$ 27,629,800

See accompanying notes to financial statements.

DGOC SERIES 18(C), L.P.
STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2017 AND 2016

	2017	2016
Cash flows from operating activities:		
Net income (loss)	$ 2,003,100	$ (286,600)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion	2,080,600	2,537,200
Impairment	35,400	—
Non-cash loss on derivative value	—	747,800
Accretion of asset retirement obligations	131,400	124,900
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable trade-affiliate	(186,200)	168,800
Increase in asset retirement receivable-affiliate	(147,100)	(64,000)
(Decrease (increase) in accrued liabilities	(10,800)	19,400
Net cash provided by operating activities	3,906,400	3,247,500
Cash flows from investing activities:		
Proceeds from sale of tangible equipment	—	12,000
Net cash provided by investing activities	—	12,000
Cash flows from financing activities:		
Distributions to partners	(4,155,400)	(3,181,400)
Net cash used in financing activities	(4,155,400)	(3,181,400)
Net change in cash	(249,000)	78,100
Cash at beginning of year	249,000	170,900
Cash at end of year	$ —	$ 249,000

See accompanying notes to financial statements.

DGOC SERIES 18(C), L.P.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2017 AND 2016

NOTE 1—BASIS OF PRESENTATION

DGOC Series 18(C), L.P. (the "Partnership") is a Delaware limited partnership, formed on July 6, 2017 and includes the Appalachian-based assets that were previously included within, Atlas Resources Public 18-2009(C), L.P. ("Predecessor Partnership") that was formed on June 9, 2009 and was then managed by Atlas Resources, LLC ("Atlas" or "Previous MGP"). DGOC Partnership Holdings, LLC now serves as the Partnership's Managing General Partner ("DGOC Holdings" or the "MGP") and certain affiliates of the MGP serve as our Operator ("Operator"). DGOC Holdings is an indirect subsidiary of Diversified Gas & Oil, PLC ("Diversified"; AIM: DGOC). Unless the context otherwise requires, references below to "the Partnership," "we," "us," "our" and "our company", refer to DGOC Series 18(C), L.P.

Atlas previously served as the Partnership's Managing General Partner and Operator . Atlas is an indirect subsidiary of Titan Energy, LLC ("Titan"). On May 4, 2017, Titan entered into a definitive agreement to sell, among other conventional assets, its general and limited partnership equity interest ("Equity Interest") in the Partnership to Diversified (the "Purchase and Sale Agreement" or "PSA"). The transaction was subject to customary closing conditions, had an effective date of April 1, 2017 and closed on September 29, 2017. Prior to closing the PSA, the Previous MGP delegated operational activities to an affiliate of Diversified for the Partnership's natural gas wells in Pennsylvania and Tennessee on June 30, 2017. Upon closing the PSA, the Previous MGP's Equity Interest in the Partnership was transferred to DGOC Holdings and DGOC Holdings was admitted as a substitute managing general partner of the Partnership and continues to serve as Operator.

Use of Estimates

Preparation of the Partnership's financial statements in conformity with U.S. GAAP requires the MGP to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, impairments, fair value of derivative instruments, and the probability of forecasted transactions. The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Receivables

Accounts receivable trade-affiliate on the balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the MGP performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the credit information. The Partnership extends credit on sales on an unsecured basis to many of their customers. At December 31, 2017 and 2016, the Partnership had recorded no allowance for uncollectible accounts receivable on its balance sheets.

Asset retirement receivable-affiliate on the balance sheets consist solely of the net amount withheld from distributions for the purpose of establishing a fund to cover the estimated costs of plugging and abandoning the Partnerships wells less any amounts used for the plugging and abandonment of the Partnership's wells. As amounts are withheld, they are paid to the MGP and held until the Partnerships wells are plugged and abandoned, at which time, the funds are used to cover the actual expenditures incurred. The total amount withheld from distributions will not exceed the MGP's estimate of the costs to plug and abandon the Partnership's wells. For additional information, see Note 7. The following is a reconciliation of the Partnership's asset retirement receivable-affiliate for the years indicated:

	2017	2016
Asset retirement receivable-affiliate, beginning of year	$ 170,700	$ 106,700
Asset retirement estimates withheld	147,100	64,000
Asset retirement receivable-affiliate, end of year	$ 317,800	$ 170,700

Natural Gas Properties

Natural gas properties are stated at cost. The Partnership follows the successful efforts method of accounting for natural gas producing activities. The Partnership expenses maintenance and repairs as incurred that generally do not extend the useful life or enhance the productivity of an asset for two years or more through the replacement of critical components. The Partnership capitalizes major renewals and improvements that generally extend the useful life of an asset for two years or more through the replacement of critical components. For additional information see Note 3.

Upon the sale or retirement of a complete field of a proved property, the Partnership eliminates the cost from the property accounts and the resultant gain or loss is reclassified to the Partnership's statements of operations. Upon the sale or retirement of an individual well, the Partnership reclassifies the costs associated with the well and credits the proceeds to accumulated depletion and impairment within its balance sheets.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount of that asset to its estimated fair value if such carrying amount exceeds the fair value.

The MGP reviews the Partnership's natural gas properties on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion and impairment is less than the estimated expected undiscounted future cash flows including salvage. The MGP estimates the expected future cash flows based on the Partnership's plans to continue to produce and develop proved reserves. The MGP calculates the expected future cash flow from the sale of the production of reserves based on estimated future prices. The Partnership estimates prices based upon current contracts in place, adjusted for basis differentials and market related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, we recognize impairment loss for the difference between the estimated fair market value (as determined by the discounted cash flows) and the carrying value of the assets.

Determination of natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. The Partnership cannot predict what reserve revisions may be required in future periods. For additional information see Note 3.

Derivative Instruments and Other Comprehensive Loss

The Partnership's Previous MGP entered into certain financial derivative contracts to manage the Partnership's exposure to changes in commodity prices. The derivative instruments recorded on the balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument's fair value were recognized in the Partnership's statements of operations unless specific hedge accounting criteria were met. On January 1, 2015, the Partnership discontinued hedge accounting through de-designation for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value after December 31, 2015 of these derivatives were recognized immediately within loss on mark-to-market derivatives in the Partnership's statements of operations, while the fair values of the instruments recorded in accumulated other comprehensive loss as of December 31, 2015 were reclassified to the statements of operations in the periods in which the respective derivative contracts settled. For the year ended December 31, 2016, the gain reclassified from accumulated other comprehensive loss into natural gas revenues was $700 and the gain subsequent to hedge accounting recognized in loss on mark-to-market derivatives was $18,500.

Asset Retirement Obligations

The Partnership recognizes an estimated liability for the plugging and abandonment of its natural gas wells and related facilities. The Partnership recognizes a liability for its future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. For additional information see Note 4.

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income reported in the financial statements. Accordingly, no federal or state deferred income tax has been provided for in the financial statements. The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2012. The Company's tax returns are generally subject to possible examination by the taxing authorities for a period of three years from the date they are filed, though the Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2017.

Environmental Matters

The Partnership is subject to various federal, state, and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Partnership's operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. The Partnership maintains insurance which may cover in whole or in part certain environmental expenditures. The Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability for the years ended December 31, 2017 and 2016.

Concentration of Credit Risk

The Partnership sells natural gas under contracts to various purchasers in the normal course of business. For the years ended December 31, 2017 and 2016, the Partnership had the following customers that individually accounted for greater than 10% of the Partnership's natural gas revenues, excluding the impact of all financial derivative activity.

	Percentage of Revenue	
Customer	**2017**	**2016**
Direct Energy Business LLC	73%	—%
Dominion Field Services, Inc.	11%	15%
Hess Energy Marketing, LLC	—%	52%
Atmos Energy Marketing, LLC	—%	24%
Other (no single customer accounts for more than 10% of revenues)	16%	9%
Total	100%	100%

Revenue Recognition

The Partnership generally sells natural gas at prevailing market prices. Generally, the Partnership's sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines for natural gas and the quality of its natural gas. Generally, the market index is fixed two business days prior to the commencement of the production month. The MGP recognizes revenue and the related accounts receivable when the MGP delivers the produced quantities to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. The Partnership recognizes revenues from the production of natural gas in which the Partnership has an interest with other producers on the basis of its percentage ownership of the working interest and/or overriding royalty.

The MGP and its affiliates perform all administrative and management functions for the Partnership including billing and collecting revenues and paying expenses. Accounts Receivable Trade-Affiliate on the Partnership's balance sheets includes the net production revenues due from the MGP. The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, and the receipt of a delivery statement. The MGP records revenues based upon volumetric data from the Partnership's records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at December 31, 2017 and 2016 of $817,700 and $913,600, respectively, which were included in accounts receivable trade-affiliate within the Partnership's balance sheets.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU 2014-09 by one year. As a result, the standard is effective for annual periods beginning on or after December 31, 2017, including interim periods within that reporting period. The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoption.

At December 31, 2017, the MGP has completed the evaluation of sources of revenue and the impact of this accounting standards update on our results of operations, financial position, cash flows and financial disclosures, in addition to developing and implementing any process or control changes necessary. We do not expect to record a cumulative effect adjustment on date of adoption. The Partnership adopted the new standard on January 1, 2018 using the modified retrospective method at the date of adoption.

NOTE 2—PARTICIPATION IN REVENUES AND COSTS (WORKING INTEREST)

The MGP allocates revenues and expenses to the MGP and limited partners based on their proportion of capital contributions to total contributions ("working interest") per the partnership agreement. The MGP has provided an additional working interest of 10% as provided in the partnership agreement. The MGP determined the final working interest ownership of the partners once the wells were producing. The MGP and the limited partners generally participated in revenues and costs in the following manner:

	Managing General Partner	Limited Partners
Organization and offering cost	100%	—%
Lease costs	100%	—%
Intangible drilling costs	2%	98%
Tangible drilling costs	40%	60%
Revenues[(1)]	28%	72%
Operating costs, administrative costs, direct and all other costs[(2)]	28%	72%

(1) All partnership revenues will be shared in the same percentage as capital contributions are to the total partnership capital contributions, except that the MGP will receive an additional 10% of the partnership revenues.
(2) These costs will be charged to the partners in the same ratio as the related production revenues are credited.

NOTE 3—PROPERTY, PLANT AND EQUIPMENT

The following is a summary of proved natural gas properties at the dates indicated:

	December 31,	
	2017	2016
Proved properties:		
Leasehold interests	$ 1,660,400	$ 1,660,400
Wells and related equipment	210,127,800	210,127,800
Total natural gas properties	211,788,200	211,788,200
Accumulated depletion and impairment	(182,999,800)	(180,883,800)
Natural Gas properties, net	$ 28,788,400	$ 30,904,400

The Partnership recorded depletion expense on natural gas properties of $2,080,600 and $2,537,200 for the years ended December 31, 2017 and 2016, respectively.

NOTE 4—ASSET RETIREMENT OBLIGATIONS

The estimated liability for asset retirement obligations is based on the MGP's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells or if federal or state regulators enact new plugging and abandonment requirements. The Partnership has no assets legally restricted for purposes of settling asset retirement obligations.

The MGP's historical practice and continued intention is to retain distributions from the limited partners up to the fair value of the future plugging and abandonment costs. As of December 31, 2017 and 2016, the MGP and the Previous MGP withheld $317,800 and $170,700, respectively, of net production revenue for future plugging and abandonment costs. The following table reconciles the Partnership's asset retirement obligation liability for well plugging and abandonment costs:

	Years Ended December 31,	
	2017	2016
Asset retirement liability, beginning of year	$ 2,641,800	$ 2,516,900
Accretion expense	131,400	124,900
Asset retirement liability, end of year	$ 2,773,200	$ 2,641,800

NOTE 5—FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership has established a hierarchy to measure its financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1–Unadjusted quoted prices for identical instruments in active markets.

Level 2–Quoted prices for similar instruments.

Level 3–Valuations that are significant and unobservable.

Financial Instruments

The Partnership determines its estimated fair value of the Partnership's financial instruments, which include current assets and liabilities, based upon its assessment of available market information and valuation methodologies. The Partnership has categorized the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature as Level 1.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Asset Retirement Obligations

The Partnership estimates the fair value of its asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments discussed in Note 5. The MGP made no adjustments to retirement obligations for the years ended December 31, 2017 and 2016 and would define them, if applicable, as Level 3 fair value measurements. For additional information see Note 4.

Long-Lived Assets:

The Partnership estimates the fair value of its long-lived assets in conjunction with the review of assets for impairment or whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions, and judgments regarding such events or circumstances. For the years ended December 31, 2017 and 2016, the Partnership recognized no impairments of its long-lived natural gas properties, which we would define, if applicable, as Level 3 fair value measurements. For additional information see Note 3.

NOTE 6 —CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The Partnership has entered into the following significant transactions with the MGP and its affiliates as provided under its partnership agreement. Administrative costs, which are included in general and administrative expenses in the Partnership's statements of operations, are payable at $75 per well per month. Direct costs, which are included in production and general and administrative expenses in the Partnership's statements of operations, are payable to the MGP and its affiliates as reimbursement for all costs expended on the Partnership's behalf. Monthly well supervision fees of $975 per well per month for Marcellus wells and for all other wells a fee of $392 is charged per well per month for operating and maintaining the wells. Well supervision fees are proportionately reduced to the extent the Partnership does not acquire 100% of working interest in a well. Transportation fees are included in production expenses in the Partnership's statements of operations and are generally payable at either 16% of the natural gas sales price or $0.35 per Mcf, whichever is greater. The MGP and its affiliates, with administrative support from the Previous MGP under the previously mentioned TSA, perform all administrative and management functions for the Partnership, including billing revenues and paying expenses. The following table provides information with respect to these costs and the periods incurred:

	Years Ended December 31,			
	2017	2016	$ Change	% Change
Transportation fees	$ 941,800	$ 704,000	$ 237,800	34 %
Supervision fees	712,600	737,400	(24,800)	(3)%
Direct costs	483,200	531,900	(48,700)	(9)%
Total production costs	$ 2,137,600	$ 1,973,300	$ 164,300	8 %
Administrative fees	$ 54,800	$ 56,700	$ (1,900)	(3)%
Direct Costs	76,900	77,800	(900)	(1)%
Total general and administrative	$ 131,700	$ 134,500	$ (2,800)	(2)%

NOTE 7—COMMITMENTS AND CONTINGENCIES

General Commitments

Subject to certain conditions, investor partners may present their interests for purchase by the MGP. The purchase price is calculated by the MGP in accordance with the terms of the partnership agreement. In the event that the MGP is unable to obtain the necessary funds, it may suspend its purchase obligation.

Beginning one year after each of the Partnership's wells was placed into production, the MGP, as operator, exercised its right to retain $200 per month per well to cover estimated future plugging and abandonment costs. For additional information refer to Note 5.

Environmental risk is inherent to natural gas operations, and we and our affiliates may be, at times, subject to potential environmental remediation liability. At December 31, 2017, there were no unresolved environmental matters. For additional information refer to Note 1.

Legal Proceedings

From time to time, the Partnership and affiliates of the MGP and their subsidiaries are party to various routine legal proceedings arising out of the ordinary course of its business. The MGP believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Partnership's or the MGP's financial condition or results of operations. As of December 31, 2017, there were no outstanding legal proceedings.

NOTE 8—SUPPLEMENTAL GAS INFORMATION (UNAUDITED)

Natural Gas Reserve Information. The MGP's reserve engineers prepared the Partnership's natural gas reserve estimates in accordance with our MGP's prescribed internal control procedures. For the periods presented, the MGP retained Wright & Company, Inc., the MGP's independent third-party reserve engineer, to prepare a report of proved reserves related to the Partnership. The reserve information for the Partnership includes natural gas reserves which are all located in the United States. The independent reserves engineer's evaluation was based on more than 41 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. The MGP's internal control procedures include verification of input data delivered to its third-party reserve specialist. Our MGP's Vice President of Gas Marketing, who has more than 18 years of natural gas and oil industry experience, oversaw the preparation, review and approval of reserve estimates with final approval by the MGP's Chief Operating Officer.

The reserve disclosures that follow reflect estimates of proved developed reserves of natural gas owned at year end, net of royalty interests. Proved developed reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The proved reserves quantities and future net cash flows were estimated using an unweighted 12-month average pricing based on the prices on the first day of each month during the years ended December 31, 2017 and 2016, including adjustments related to regional price differentials and energy content. We experienced significant downward revisions of our natural gas reserves volumes and values in 2016 and 2017 due to the significant declines in commodity prices.

Numerous uncertainties are inherent in estimating quantities of proven reserves and in projecting future net revenues and the timing of development expenditures. The reserve data presented represents estimates only and should not be construed as being exact. In addition, the standardized measures of discounted future net cash flows may not represent the fair market value of natural gas reserves included within the Partnership or the present value of future cash flows of equivalent reserves, due to anticipated future changes in natural gas prices and in production and development costs and other factors. Reserve quantity information and a reconciliation of changes in proved reserve quantities included within the Partnership are as follows:

	Gas (Mcf)
Balance, December 31, 2015	40,438,800
Revisions(1)	1,037,300
Production	(3,205,800)
Balance, December 31, 2016	38,270,300
Revisions (2)	(1,526,300)
Production	(2,622,500)
Balance, December 31, 2017	34,121,500

(1) The upward revision in natural gas forecasts is primarily due to production forecast adjustments in order to reflect actual production.
(2) The downward revision is primarily due to future production forecast adjustments in our Marcellus field to reflect realized production declines.

Standardized Measure of Discounted Future Cash Flows. The following schedule presents the standardized measure of estimated discounted future net cash flows relating to the Partnership's proved natural gas reserves using the pricing methodology described above. The resulting estimated future cash inflows were reduced by estimated future costs to produce the proved reserves based on year-end cost levels, and includes the effect on cash flows of settlement of asset retirement obligations on gas properties, with the net result discounted to present value by applying a 10% discount factor. The standardized measure of future cash flows was prepared using the prevailing economic conditions existing at the dates presented and such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of recoverable reserves or in estimating future results of operations:

	Years Ended December 31,	
	2017	2016
Future cash inflows	$ 83,256,500	$ 47,024,500
Future production costs	(38,453,700)	(18,532,000)
Future development costs(1)	(2,778,600)	—
Future net cash flows	42,024,200	28,492,500
Less 10% annual discount for estimated timing of cash flows	(23,628,300)	(15,790,900)
Standardized measure of discounted future net cash flows	$ 18,395,900	$ 12,701,600

(1) Future development costs represent costs to plug and abandon wells at the end of the estimated economic life of a well.

ITEM 9: CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A: CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our MGP's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2017 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting (such as term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

The management of our general partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including our MGP's principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 2013 Internal Control - Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

Based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2017.

This annual report does not include an attestation report by our registered public accounting firm regarding internal control over financial reporting because such a report is not required pursuant to the rules of the Securities and Exchange Commission.

PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Our general partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us.

Officers and Key Operations Employees of Our General Partner

The Partnership has no officers. Rather, our Managing General Partner has the following individuals who serve as its officers and on its board of directors:

Name	Age	Position(s)
Robert "Rusty" R. Hutson Jr.	48	Chief Executive Officer
Bradley G. Gray	48	Finance Director and Chief Operating Officer
Eric M. Williams	39	Chief Financial Officer
John "Jack" W. Crook	59	Senior Vice President of Environmental, Health and Safety
William "Bill" Kurtz	52	Vice President, Gas Marketing

Robert “Rusty” R. Hutson Jr., (48), Chief Executive Officer

Mr. Hutson Jr. is the Chief Executive Officer of the general partner and has served as Chief Executive Officer of Diversified since its inception in 2001. Mr. Hutson Jr. is the fourth generation of his family to be involved in the oil and natural gas industry but the first to hold an executive role, with his father, grandfather and great grandfather all working in various field operational roles. Before founding Diversified Gas & Oil in 2001, Mr. Hutson Jr. held finance and accounting roles for 13 years at Bank One (Columbus, Ohio) and Compass Bank (Birmingham, Alabama). He finished his banking career as CFO of Compass Financial Services. Mr. Hutson has a B.S. degree in Accounting from Fairmont State College – West Virginia. He is a former certified public accountant (“CPA”) (Ohio).

Bradley G. Gray, (48), Finance Director and Chief Operating Officer

Mr. Gray serves as the Chief Operating Officer of the general partner and has serviced as Chief Operating officer of Diversified since October 2016. Prior to joining the Company in October 2016, Mr. Gray held the position of Senior Vice President and Chief Financial Officer for Royal Cup, Inc., a United States based commercial coffee roaster and wholesale distributor of tea and other beverage related products. Prior to Royal Cup, Inc., from 2006 to 2014, Mr. Gray worked in the petroleum distribution industry for The McPherson Companies, Inc. and held the position of Executive Vice President and Chief Financial Officer. Additionally, from 1997 to 2006, Mr. Gray worked in various financial and operational roles with Saks Incorporated, a previously listed New York Stock Exchange retail group in the United States. Mr Gray began his career at Arthur Andersen. Mr. Gray has a B.S. degree in Accounting from the University of Alabama and he is a licensed CPA (Alabama).

Eric M. Williams, (39), Chief Financial Officer

Mr. Williams joined Diversified in July 2017 from Callon Petroleum. During Eric’s more than seven-year tenure with Callon, the company grew significantly from a market capitalization of $40 million to over $3.5 billion, successfully transforming itself from a deep-water asset focused company to an onshore, pure-play horizontal drilling operator in the Permian Basin. Mr. Williams was instrumental in developing and enhancing the company’s external reporting streams, and established a formal investor relations function serving more than 30 sell-side analysts and a growing base of institutional investors. Mr. Williams began his career in PwC’s Birmingham, Alabama audit practice, and prior to his time at Callon, served in various roles including internal audit with a focus on Sarbanes Oxley implementation and compliance, controllership and financial reporting for several US publicly traded companies. Mr. Williams has a B.S. degree in Accounting from Samford University, a M.S. degree in Accounting from the University of Alabama and he is a licensed CPA (Alabama).

John "Jack" W. Crook, (59), Senior Vice President of Environmental, Health and Safety

Jack Crook is a licensed geologist with 36 years of oil and natural gas experience in environmental, health, safety and regulatory compliance. Mr. Crook started his career with the Pennsylvania Department of Environmental Protection and gained extensive knowledge within this field by taking on roles in the Department's hydrology, water supply and oil and natural gas divisions. In 2012, Mr. Crook joined Titan as Vice President of Environmental, Health, Safety, Regulatory, and Security compliance. At Titan he oversaw safety policies, procedures and training and served on the Executive Committee. Mr. Crook is an Executive Board Member and Secretary of the Board of Pennsylvania Independent Oil & Gas Association. Mr. Cayton and Mr. Crook will be appointed by the Group following Completion.

William M. Kurtz, (52), Vice President of Energy Marketing

Mr. Kurtz joined the Company in 2017, bringing extensive experience that spans a 35-year career in the Oil & Gas Industry. His talents focused on advising and executing mergers & acquisitions, divestitures, and joint ventures for multiple organizations. His ongoing focus includes energy marketing. Mr. Kurtz began his career in 1983 as a Cartographer. Early in his career, he held subsequent positions that included Appalachian Landman, Surveyor, Appalachian Land Manager, and Senior Production Manager. During this time, he worked with multiple organizations including Atwood Energy, Inc., Transfuel Resources (Mitsubishi), and Lomak Petroleum (aka Range Resources). Immediately prior to joining the Company, Mr. Kurtz was employed with Atlas Energy, Inc. for 21 years where he held diverse positions that included Director of Business Development, Director of Production, and Senior Manager - Project Development. Mr. Kurtz is an active member of American Association of Professional Landmen, Society of Petroleum Engineers, and the Ohio Oil & Gas association where he serves on the Producers Committee.

Code of Business Conduct and Ethics

Because the Partnership does not directly employ any persons, the MGP has determined that the partnership will rely on a code of business conduct and ethics that applies to the principal executive officer, principal financial officer, and principal accounting officer of our general partner, as well as to persons performing services for us generally.

ITEM 11: EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We do not directly employ any persons to manage or operate our businesses. Instead, all of the persons (including executive officers of our MGP and other personnel) necessary for the management of our business were employed and compensated by Atlas Energy Group, Titan's parent company, through a Transition Services Agreement ("TSA") effective through December 31, 2017. After expiration of the TSA, staffing is provided by an affiliate of Diversified Gas and Oil PLC. Pursuant to our partnership agreement, our general partner manages our operations and activities through its and its affiliates' employees (including employees of Atlas Energy Group and its MGP through a TSA). No officer or director of our MGP receives any direct remuneration or other compensation from us. (See "Item 13: Certain Relationships and Related Transactions" for a discussion of compensation paid by us to our MGP).

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

As of December 31, 2017, we had 22,928.90 units outstanding. No officer or director of our MGP owns any units. Although, subject to certain conditions, investor partners may present their units to us for purchase, though the MGP is not obligated by the partnership agreement to purchase more than 5% of our total outstanding units in any calendar year. The MGP is owned 100% by Diversified. The Partnership does not have any equity compensation plans in place. The MGP is owned 100% by Diversified.

ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Our Relationship with DGOC Partnership Holdings, LLC

Natural Gas Revenues. Our MGP is allocated 27.92% of our natural gas revenues in return for its payment and/or contribution of services towards our syndication and offering costs equal to 10.36% of our subscriptions, its payment of 43.61% of the tangible costs and 1.54% of intangible costs of drilling and completing our wells and its contributions to us of all of our natural gas leases for a total capital contribution of $49,997,500. During the years ended December 31, 2017 and 2016, our MGP received net production revenues of $1,225,000 and $726,700, respectively.

For additional information see Part II, Item 7 and Item 8.

Other Compensation. For the years ended December 31, 2017 and 2016, our MGP did not advance any funds to us, nor did it provide us with any equipment, supplies or other services.

ITEM 14: PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the year ended December 31, 2017, the accounting fees and services charged by Grant Thornton, LLP, our independent auditors, was $36,400. This amounts excludes fees related to the Spin-off (e.g., audit of the financial statements included in the Partnership's registration statement on Form 10) and other audit and non-audit fees, all which were borne by the Previous MGP.

Audit Committee Pre-Approval Policies and Procedures

The audit committee of our general partner, on at least an annual basis, will review audit and non-audit services performed by Grant Thornton LLP as well as the fees charged by Grant Thornton LLP for such services. Our policy is that all audit and non-audit services must be pre-approved by the audit committee. All of such services and fees were pre-approved during 2017 and 2016.

PART IV

ITEM 15: EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

EXHIBIT INDEX

	Description
4.1	Certificate of Limited Partnership for DGOC Series 18(C), L.P. (incorporated by reference to Exhibit 3.1 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
4.2	Certificate and Agreement of Limited Partnership for DGOC Series 18(C), L.P. (incorporated by reference to Exhibit 3.2 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
4.3	Drilling and Operating Agreement for Atlas Resources Public #18-2009 (C) L.P. (incorporated by reference to Exhibit (II) to the Form S-1/A Registration Statement of Atlas Resources Public #18-2009 (C) L.P. dated October 15, 2008, as amended)
10.1	Transition Services Agreement dated as of June 30, 2017 by and among Titan Energy Operating, LLC, Diversified Energy, LLC and Diversified Gas & Oil Corporation (incorporated by reference to Exhibit 10.1 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
10.2	Form Assignment of Equity Interests (incorporated by reference to Exhibit 10.2 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
10.4	Partial Assignment Agreement by and between Atlas Resources Public #18-2009 (C) L.P. and DGOC Series 18(C), L.P. (incorporated by reference to Exhibit 10.4 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
10.5	Partial Assignment Agreement by and between Atlas Resources, LLC and Atlas Energy Tennessee, LLC and Diversified Oil & Gas, LLC (incorporated by reference to Exhibit 10.5 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
10.6	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. (incorporated by reference to Exhibit 10.2 to the Form 10-12G Registration Statement of Atlas Resources Series 28-2010 L.P. dated April 29, 2011 as amended)
21.1	Subsidiaries of DGOC Series 18(C), L.P. (incorporated by reference to Exhibit 21.1 to the Partnership's Form 10-12G Registration Statement filed on September 8, 2017)
23.1(a)	Consent of Wright & Company, Inc.
31.1(a)	Rule 13a-14(a)/15(d) – 14 (a) Certification
31.2(a)	Rule 13a-14(a)/15(d) – 14 (a) Certification.
32.1(b)	Section 1350 Certification.
32.2(b)	Section 1350 Certification.
99.1(a)	Summary Reserve Report
101(c)	Interactive Data File

(a) Filed herewith

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities of the Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DGOC Series 18(C), L.P.

BY: DGOC PARTNERSHIP HOLDINGS, LLC, ITS MANAGING GENERAL PARTNER

Date: March 28, 2018

By: /s/ ROBERT R. HUTSON, JR.

Robert R. Hutson, Jr., Chief Executive Officer (principal executive officer) of the Managing General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following person on behalf of the registrant and in the capacities and on the dates indicated.

Date: March 28, 2018

By: /s/ ROBERT R. HUTSON, JR.

Robert R. Hutson, Jr., Chief Executive Officer (principal executive officer) of the Managing General Partner

Date: March 28, 2018

By: /s/ BRADLEY G. GRAY

Bradley G. Gray, Chief Operating Officer (principal financial officer) of the Managing General Partner

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM CONSULTANTS

Wright & Company, Inc. hereby consents to the use of our analysis relating to the evaluation titled *Evaluation of Oil and Gas Reserves, To the Interests of the DGOC Series 18(C), LP Partnership, Managed by Diversified Gas & Oil PLC, Pursuant to the Requirements of the United States Securities and Exchange Commission, Effective January 1, 2018, Job 18.1947-C* dated February 26, 2018, for use in the Annual Report on Form 10-K for the year ended December 31, 2017, filed with the Securities and Exchange Commission, and to all references to Wright & Company, Inc. as having prepared such analysis and as an expert concerning such analysis.

Wright & Company, Inc.
TX Reg. No. F-12302

By: /s/D. Randall Wright
D. Randall Wright
President

Wright & Company, Inc.
Brentwood, Tennessee
March 28, 2018

Exhibit 31.1

CERTIFICATION

I, Robert R. Hutson Jr. , certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2017 of Atlas Resources Public #18-2009 (C) L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ROBERT R. HUTSON JR.

Robert R. Hutson Jr.

Chief Executive Officer (principal executive officer) of the Managing General Partner

March 28, 2018

Exhibit 31.2

CERTIFICATION

I, Bradley G. Gray, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2017 of Atlas Resources Public #18-2009 (C) L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BRADLEY G. GRAY

Bradley G. Gray

Chief Operating Officer (principal financial officer) of the Managing General Partner

March 28, 2018

Exhibit 32.1

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Atlas Resources Public #18-2009 (C) L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert R. Hutson Jr., Chief Executive Officer (principal executive officer) of the Managing General Partner, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ ROBERT R. HUTSON JR.

Robert R. Hutson Jr.
Chief Executive Officer (principal executive officer) of the Managing General Partner
March 28, 2018

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Atlas Resources Public #18-2009 (C) L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bradley G. Gray, Chief Operating Officer (principal financial officer) of the Managing General Partner, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(a) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ BRADLEY G. GRAY

Bradley G. Gray
Chief Operating Officer (principal financial officer) of the Managing General Partner
March 28, 2018

Exhibit 99.1

February 26, 2018

Diversified Gas & Oil PLC
1100 Corporate Drive
Birmingham, AL 35242

Attention: Mr. Bradley G. Gray

SUBJECT: Evaluation of Oil and Gas Reserves
To the Interests of the DGOC Series 18(C), LP Partnership
Managed by Diversified Gas & Oil PLC
Pursuant to the Requirements of the
United States Securities and Exchange Commission
Effective January 1, 2018
Job 18.1947-C

At the request of Diversified Gas & Oil PLC (DGO), Wright & Company, Inc. (Wright) has performed an evaluation to estimate proved reserves and associated cash flow and economics from certain properties to the interests of the DGOC Series 18(C), LP Partnership (Partnership). This evaluation was authorized by Mr. Bradley G. Gray of DGO, the Managing General Partner of the Partnership. Projections of the reserves and cash flow to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered applicable at the effective date. This reserves evaluation is pursuant to the financial reporting requirements of the United States (U.S.) Securities and Exchange Commission (SEC) as specified in Regulation S-X, Rule 4-10(a) and Regulation S-K, Rule 1202(a)(8). It is the understanding of Wright that the purpose of this evaluation is for inclusion in relevant registration statements or other filings to the SEC for the fiscal year ended December 31, 2017. The effective date of this report is January 1, 2018, and the report was completed February 26, 2018. The following is a summary of the results of the evaluation.

DGOC Series 18(C), LP Pursuant to SEC	Total Proved (PDP & PDNP)
Net Reserves to the Evaluated Interests	
Oil, Mbbl:	0.000
Gas, MMcf:	34,121.504
NGL, Mbbl:	0.000
Gas Equivalent, MMcfe: (1 bbl = 6 Mcfe)	34,121.504
Cash Flow (BTAX), M$	
Undiscounted:	42,024.168
Discounted at 10% Per Annum:	18,395.848

Please note numbers in table may not add due to rounding techniques in the ARIES™ petroleum software program.

The properties evaluated in this report are located in Pennsylvania and Tennessee. According to DGO, the total proved reserves included in this evaluation represent 100 percent of the reported total proved reserves of the Partnership. The interests evaluated in this report represent the total interests of the Partnership.

Proved oil and gas reserves are those quantities of oil and gas that can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods, and government regulations. As specified by the SEC regulations, when calculating economic producibility, the base product price must be the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the prior 12-month period. The benchmark base prices used for this evaluation were $51.34 per barrel for West Texas Intermediate oil at Cushing, Oklahoma, and $2.976 per million British thermal units (MMBtu) for natural gas at Henry Hub, Louisiana. These benchmark base prices were adjusted for energy content, quality, and basis differential, as appropriate. The resultant average adjusted gas price was $2.440 per thousand cubic feet (Mcf). The product prices and adjustments were held constant for the life of the properties.

Oil and other liquid hydrocarbon volumes are expressed in thousands of U.S. barrels (Mbbl) of 42 U.S. gallons. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. No adjustment of the individual gas volumes to a common pressure base has been made. Wright determined that no oil or natural gas liquids (NGL) reserves are expected to be realized from the properties included in this evaluation.

Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, state and county taxes, state fees, operating expenses, investments, salvage values, and abandonment costs, as applicable. The cash flow is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. The cash flow (BTAX) was discounted monthly at an annual rate of 10.0 percent in accordance with the reporting requirements of the SEC.

The estimates of reserves contained in this report were determined by accepted industry methods, and the procedures used in this evaluation are appropriate for the purpose served by the report. Where sufficient production history and other data were available, reserves for producing properties were determined by extrapolation of historical production or sales trends. Analogy to similar producing properties was used for development projects and for those properties that lacked sufficient production history to yield a definitive estimate of reserves. When appropriate, Wright may have also utilized volumetric calculations and log correlations in the determination of estimated ultimate recovery (EUR). These calculations are often based upon limited log and/or core analysis data and incomplete formation fluid and rock data. Since these limited data must frequently be extrapolated over an assumed drainage area, subsequent production performance trends or material balance calculations may cause the need for significant revisions to the estimates of reserves. Wright has used all methods and procedures as it considered necessary under the circumstances to prepare this report.

Gas reserves were evaluated for the proved developed producing (PDP) and proved developed nonproducing (PDNP) categories. The summary classification of total proved reserves combines the PDP and PDNP categories. In preparing this evaluation, no attempt has been made to quantify the element of uncertainty associated with any category. Reserves were assigned to each category as warranted. Wright is not aware of any local, state, or federal regulations that would preclude the Partnership or DGO from continuing to produce from currently active wells or to fully develop those properties included in this report.

There are significant uncertainties inherent in estimating reserves, future rates of production, and the timing and amount of future costs. The estimation of oil and gas reserves must be recognized as a subjective process that cannot be measured in an exact way, and estimates of others might differ materially from those of Wright. The accuracy of any reserves estimate is a function of the quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates or changes in the analogous properties may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

All data utilized in the preparation of this report were provided by DGO. No inspection of the properties was made as this was not considered to be within the scope of this evaluation. Wright has not independently verified the accuracy and completeness of information and data furnished by DGO with respect to ownership interests, oil and gas production or sales, historical costs of operation and development, product prices, or agreements relating to current and future operations and sales of production. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by DGO with regard to product pricing, appropriate adjustments, and lease operating expenses. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, Wright did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. In accordance with the requirements of the SEC, all operating costs were held constant for the life of the properties.

In accordance with the instructions of DGO, the cost of abandonment and the salvage value of equipment at abandonment have been included on all commercial wells in this evaluation at the end of the economic life. Wright has not performed a detailed study of the abandonment costs nor the salvage values and offers no opinion as to DGO's calculations and assumptions.

Wright is not aware of any potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this evaluation for potential property restoration, liability, or clean up of damages, if any, that may be necessary due to past or future operating practices.

Wright is an independent petroleum consulting firm founded in 1988 and owns no interests in the gas properties covered by this report. No employee, officer, or director of Wright is an employee, officer, or director of the Partnership or DGO, nor does Wright or any of its employees have direct financial interest in the Partnership or DGO. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report.

This report is prepared for the information of the Partnership, DGO, their investors, and for the information and assistance of its independent public accountants in connection with their review of and report upon the financial statements of the Partnership and DGO, and for reporting disclosures as required by the SEC. This report is also intended for public disclosure as an exhibit in filings made to the SEC by the Partnership and DGO.

Based on data and information provided by DGO, and the specified economic parameters, operating conditions, and government regulations considered applicable at the effective date, it is Wright's conclusion that this report provides a fair and accurate representation of the oil and gas reserves to the interests of the Partnership in those certain properties included in this report.

The professional qualifications of the petroleum consultants responsible for the evaluation of the reserves and economics information presented in this report meet the standards of Reserves Estimator as defined in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* as promulgated by the Society of Petroleum Engineers.

It has been a pleasure to serve you by preparing this evaluation. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.

By: /s/D. Randall Wright
D. Randall Wright
President

DRW/EKL/JDS/SLM/crd
01_Letter_DGOC Series 18(C), LP _18.1947-C.docx