Diamondback Energy, Inc.
Form 10-K
February 25, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices)	79701 (Zip Code)

(Registrant Telephone Number, Including Area Code): (432) 221-7400

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The Nasdaq Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý 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 ý

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 ý No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	ý	Accelerated Filer	¨
Non-Accelerated Filer	¨	Smaller Reporting Company	¨
		Emerging Growth Company	o

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. o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 29, 2018 was approximately $11,455,114,815.

As of February 15, 2019, 164,381,522 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2019 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms used in this report:

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels per day.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
Brent	Brent sweet light crude oil.
British Thermal Unit or BTU	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Condensate	Liquid hydrocarbons associated with the production that is primarily natural gas.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Developed acreage	Acreage assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole or dry well	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Estimated Ultimate Recovery or EUR	Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
Exploitation	A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Finding and development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Fracturing	The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
Mb/d	Thousand barrels per day.
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf	Thousand cubic feet of natural gas.
Mcf/d	Thousand cubic feet of natural gas per day.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.

MMcf	Million cubic feet of natural gas.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD	Proved undeveloped.
Productive well	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves	Proved 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.
Recompletion	The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
Reserves	Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Resource play	

	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development or operations.
Spacing	The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.
Stratigraphic play	An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.
Structural play	An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.
Tight formation	A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI	West Texas Intermediate.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms that are used in this report.

Bison	Bison Drilling and Field Services, LLC.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
EPA	U.S. Environmental Protection Agency.
Equity Plan	The Company's Equity Incentive Plan.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
2024 Indenture	The indenture relating to the 2024 Senior Notes, dated as of October 28, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
2025 Indenture	The indenture relating to the 2025 Senior Notes, dated as of December 20, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
Operating Company	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of the Partnership.
OSHA	Federal Occupational Safety and Health Act.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
2024 Senior Notes	The Company's 4.750% senior unsecured notes due 2024 in the aggregate principal amount of $1,250 million.
2025 Senior Notes	The Company's 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $800 million.
Senior Notes	The 2024 Senior Notes and the 2025 Senior Notes.
Viper	Viper Energy Partners L.P.
Viper LTIP	Viper Energy Partners L.P. Long Term Incentive Plan.
Viper Offering	The Partnerships' initial public offering.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are int identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report on Form 10–K, including under Part I, Item 1A. "Risk Factors" in this report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- acquisitions, including our recent acquisition of certain leasehold acres and other assets from Ajax Resources, LLC and our recent acquisition of Energen Corporation discussed elsewhere in this report;
- our ability to achieve the anticipated synergies, operational efficiencies and returns from our recent acquisition of Energen Corporation;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities laws. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

PART I

Except as noted, in this Annual Report on Form 10-K, we refer to Diamondback, together with its consolidated subsidiaries, as “we,” “us,” “our,” or “the Company”. This report includes certain terms commonly used in the oil and gas industry, which are defined above in the “Glossary of Oil and Natural Gas Terms.”

ITEM 1. BUSINESS AND PROPERTIES

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators.

We began operations in December 2007 with our acquisition of 4,174 net acres in the Permian Basin. At December 31, 2018, our total acreage position in the Permian Basin was approximately 604,367 gross (461,218 net) acres, which consisted primarily of approximately 231,100 gross (194,661 net) acres in the Midland Basin and approximately 232,143 gross (170,205 net) acres in the Delaware Basin. In addition, we, through our publicly traded subsidiary Viper Energy Partners LP, which we refer to as Viper or the Partnership, own mineral interests underlying approximately 532,295 gross acres and 14,841 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 37% of these net royalty acres are operated by us. We own Viper Energy Partners GP LLC, the general partner of Viper, which we refer to as the general partner, and we own approximately 59% of the limited partner interest in Viper.

Our activities are primarily focused on horizontal development of the Spraberry and Wolfcamp formations of the Midland Basin and the Wolfcamp and Bone Spring formations of the Delaware Basin, both of which are part of the larger Permian Basin in West Texas and New Mexico. The Permian Basin is characterized by high oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates.

As of December 31, 2018, our estimated proved oil and natural gas reserves were 992,001 MBOE (which includes estimated reserves of 63,136 MBOE attributable to the mineral interests owned by Viper), based on reserve reports prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 65% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 416 gross (374 net) horizontal well locations in which we have a working interest, and 25 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2018, our estimated proved reserves were approximately 63% oil, 18% natural gas liquids and 19% natural gas.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 11,868 gross (7,633 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $60.00 per Bbl WTI. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through additional acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves.

Merger with Energen Corporation and Other Significant 2018 Transactions

Merger with Energen Corporation

On November 29, 2018, we completed our acquisition of Energen Corporation, or Energen, in an all-stock transaction, which we refer to as the merger. The addition of Energen's assets increased our assets to: (i) over 273,000 net Tier One acres in the Permian Basin, an increase of 57% from third quarter 2018 Tier One acreage of approximately 174,000 net acres, (ii) over 7,200 estimated total net horizontal Permian locations, an increase of over 120% from third quarter 2018 estimated net locations, and (iii) approximately 394,000 net acres across the Midland and Delaware Basins.

Ajax Resources, LLC

On October 31, 2018, we acquired certain leasehold interests and related assets of Ajax Resources, LLC, which we refer to as Ajax, which acquisition included approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900.0 million in cash, subject to certain adjustments, and approximately 2.6 million shares of our common stock, which we refer to as the Ajax acquisition. The Ajax acquisition was effective as of July 1, 2018.

ExL Petroleum Management, LLC and EnergyQuest II LLC Acquisition

On October 31, 2018, we acquired certain leasehold interests and related assets of ExL Petroleum Management, LLC, ExL Petroleum Operating, Inc. and EnergyQuest II LLC, which included an aggregate of approximately 3,646 net leasehold acres in the Northern Midland Basin, for a total of $312.5 million in cash, subject to certain adjustments. These acquisitions, which we collectively refer to as the ExL acquisition, were effective as of August 1, 2018.

Drop-down Transaction

On August 15, 2018, we sold to Viper mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by us, for $175.0 million, which we refer to as the Drop-down Transaction.

Our Business Strategy

Our business strategy is to continue to profitably grow our business through the following:

- Grow production and reserves by developing our oil-rich resource base. We intend to drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital.

- Focus on increasing hydrocarbon recovery through horizontal development of stacked horizons. We have been developing multiple pay intervals in the Permian Basin through horizontal drilling and believe that there are opportunities to target additional intervals throughout the stratigraphic column. Our initial horizontal wells were completed in 2012, and since then we have been an active horizontal driller in the basin. As of December 31, 2018, we are the operator of 1,193 producing horizontal wells and have a non-operated working interest in 253 additional wells. Of these 1,446 total horizontal wells, 952 wells are in the Midland Basin, 493 wells are in the Delaware Basin and one well is in the Central Basin platform. We believe that our significant experience drilling, completing and operating horizontal wells will allow us to efficiently develop our remaining inventory and ultimately target other horizons that have limited development to date. During the year ended December 31, 2018, we were able to drill our horizontal wells in the Midland Basin with approximately 7,500 foot lateral lengths to total depth, or TD, in an average of 13 days, we drilled approximately 10,000 foot lateral wells in 15 days and we drilled approximately 13,000 foot wells in 23 days. During the year ended December 31, 2018, we were able to drill our horizontal wells in the Delaware Basin with approximately 7,500 foot lateral lengths to total depth in an average of 24 days and we drilled approximately 10,000 foot lateral wells in 31 days. Further advances in drilling and completion technology may result in economic development of zones that are not currently viable.

- Leverage our experience operating in the Permian Basin. Our executive team, which has an average of over 25 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. Our focus on efficient drilling and completion techniques is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. We believe that the experience of our executive team in deviated and horizontal drilling and completions has helped reduce the execution risk normally associated with these complex well paths. In addition, our completion techniques are continually evolving as we evaluate and implement hydraulic fracturing practices that have and are expected to continue to increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

- Enhance returns through our low cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. Our acreage position in the Wolfberry play is generally in contiguous blocks which allows us to develop this acreage efficiently with a “manufacturing” strategy that takes

advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 89% of our acreage. This operational control allows us to manage more efficiently the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 76% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- Pursue strategic acquisitions with substantial resource potential. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets. During the year ended December 31, 2018, we completed multiple acquisitions in the Midland Basin through our acquisitions of Ajax, ExL and EnergyQuest, as well as Energen. As a result, our Midland Basin acreage footprint increased from approximately 101,941 net acres to approximately 194,661 net acres as of December 31, 2018, with our Delaware Basin acreage increasing from approximately 104,719 net acres to approximately 170,205 net acres over the same period.

- Maintain financial flexibility. We seek to maintain a conservative financial position. In connection with our fall 2018 borrowing base redetermination, our borrowing base was set at $2.65 billion, and we elected a commitment amount of $2.0 billion, of which $0.5 billion was available for borrowing as of December 31, 2018. As of December 31, 2018, Viper had $411.0 million in outstanding borrowings, and $144.0 million available for borrowing, under its revolving credit facility.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- Oil rich resource base in one of North America's leading resource plays. All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Permian Basin. Our production for the year ended December 31, 2018 was approximately 72% oil, 16% natural gas liquids and 12% natural gas. As of December 31, 2018, our estimated net proved reserves were comprised of approximately 63% oil, 18% natural gas liquids and 19% natural gas.

- Multi-year drilling inventory in one of North America's leading oil resource plays. We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed price of approximately $60.00 per Bbl WTI, we currently have approximately 11,868 gross (7,633 net) identified economic potential horizontal drilling locations on our acreage based on our evaluation of applicable geologic and engineering data. These gross identified economic potential horizontal locations have an average lateral length of approximately 7,200 feet, with the actual length depending on lease geometry and other considerations. These locations exist across most of our acreage blocks and in multiple horizons. Of these 11,868 locations, 6,479 are in the Midland Basin and 5,389 are in the Delaware Basin. In the Midland Basin, 2,465 are in the Lower Spraberry or Wolfcamp B horizons where we have drilled a large number of wells, 2,200 are in the Wolfcamp A or Middle Spraberry horizons where we have drilled a limited number of wells and 1,814 are in the Clearfork, Jo Mill or Cline horizons where we have drilled very few wells. Our current location count for the Lower Spraberry horizon is based on 660 foot to 880 foot spacing in Midland, Martin, northeast Andrews, Howard and Glasscock counties, depending on the prospect area and 880 foot spacing in all other counties. For the Wolfcamp B horizon, the horizontal location count is based on 660 foot to 880 foot spacing between wells in Midland, Martin, northeast Andrews, Howard, and Glasscock counties, and 880 foot spacing in all other counties. In the Wolfcamp A horizon, the horizontal location count in based on 660 foot to 880 foot spacing in Midland, Howard and Glasscock counties, 880 foot spacing in southwest Martin county and 1,320 foot spacing in other counties. The horizontal location count for the Middle Spraberry is based on 880 foot spacing in Midland, Martin and northeast Andrews counties and 1,320 foot spacing in other counties. In the Cline and Clearfork and Jo Mill horizons, the horizontal location count is based on 880 foot to 1,320 foot spacing. In the Delaware Basin, 2,219 locations are in the Wolfcamp A or Wolfcamp B horizons, and 1,789 locations are in the 2nd Bone Spring or 3rd Bone Spring horizon and 1,381 locations are in other horizons including the Brushy Canyon, Avalon, 1st Bone Spring and Wolfcamp C. The horizontal location counts are based on 880 foot spacing in the Wolfcamp A and Wolfcamp B horizons, and 1,320

foot spacing in the Bone Spring horizons. The ultimate inter-well spacing may vary from these distances due to different factors, which would result in a higher or lower location count. In addition, we have approximately 2,617 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including additional horizontal drilling opportunities and strategic leasehold acquisitions.

- Experienced, incentivized and proven management team. Our executive team has an average of over 25 years of industry experience per person, most of which is focused on resource play development. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal

wells in addition to horizontal well reservoir and geologic expertise, which is of strategic importance as we expand our horizontal drilling activity. Prior to joining us, our Chief Executive Officer held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources.

- Favorable operating environment. We have focused our drilling and development operations in the Permian Basin, one of the longest operating hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. We believe that the geological and regulatory environment of the Permian Basin is more stable and predictable, and that we are faced with less operational risks in the Permian Basin as compared to emerging hydrocarbon basins.

- High degree of operational control. We are the operator of approximately 89% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to increase or decrease our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Our Properties

Location and Land

Our total acreage position in the Permian Basin was approximately 604,367 gross (461,218 net) acres, which consisted primarily of approximately 231,100 gross (194,661 net) acres in the Midland Basin and approximately 232,143 gross (170,205 net) acres in the Delaware Basin at December 31, 2018. We are the operator of approximately 89% of this Permian Basin acreage. In addition, we, through our subsidiary Viper, own mineral interests underlying approximately 532,295 gross acres and 14,841 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 37% of these net royalty acres are operated by us. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States.

Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Bone Spring, Wolfcamp, Cline, Strawn and Atoka formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties. Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

During the late 1990s, Atlantic Richfield Company, or Arco, began a drilling program targeting the base of the Spraberry formation at 10,000 feet, with an additional 200 to 300 feet drilled to produce from the upper portion of the Wolfcamp formation. Henry Petroleum, a private firm, owned interests in the Pegasus field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple

slick-water fracturing treatments across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum's Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum's program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they monetized a portion of their acreage position, which led to the acquisition that enabled us to begin our participation in this play. Recent advancements in enhanced recovery techniques and horizontal drilling continue to make this play attractive to the oil and gas industry. By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Wolfberry play. Since then we and most other operators are almost exclusively drilling horizontal wells in the development of unconventional reservoirs in the Permian Basin. As of December 31, 2018, we held working interests in 7,279 gross (4,678 net) producing wells and only royalty interests in 2,645 additional wells.

Geology

The Permian Basin formed as an area of rapid Pennsylvanian-Permian subsidence in response to dynamic structural influence. It is one of the largest sedimentary basins in the U.S., with established oil and gas production from several reservoirs from Permian through Ordovician in age. The term “Wolfberry” was coined initially to indicate commingled production from the Permian Spraberry, Dean and Wolfcamp formations. Time equivalent in the Delaware Basin, the “Wolfbone” play describes vertically commingled production from the Permian Bone Spring and Wolfcamp formations.

The Spraberry/Bone Spring was deposited as siliciclastic turbidites in a deep water submarine fan environment, while the Wolfcamp reservoirs consist of debris-flow and grain-flow sediments, which were also deposited in a submarine fan setting. The best carbonate reservoirs within the Wolfcamp are generally found in proximity to the Central Basin Platform, while the shale reservoirs within the Wolfcamp thicken basinward away from the Central Basin Platform. Both the Spraberry/Bone Spring and Wolfcamp contain organic-rich mudstones and shales which, when buried to sufficient depth for maturation, became the source of the hydrocarbons found both within the shales themselves and in the more conventional clastic and carbonate reservoirs between the shales. The Wolfberry and Wolfbone are unconventional “basin-centered oil” resource plays, in the sense that there is no regional downdip oil/water contact.

We have successfully developed several shale intervals within the Clearfork, Spraberry/Bone Spring and Wolfcamp formations since we began horizontal drilling in 2012. The shales exhibit low permeabilities which necessitate the need for hydraulic fracture stimulation to unlock the vast storage of hydrocarbons in these targets.

We possess, or are in the process of acquiring, 3-D seismic data over substantially all of our major asset areas. Our extensive geophysical database currently includes approximately 2,617 square miles of 3-D data. This data will continue to be utilized in the development of our horizontal drilling program and identification of additional resource to be exploited.

Production Status

During the year ended December 31, 2018, net production from our Permian Basin acreage was 47,610 MBOE, or an average of 130,439 BOE/d, of which approximately 72% was oil, 16% was natural gas liquids and 12% was natural gas.

Facilities

Our oil and natural gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/natural gas/water separation equipment and pumping units.

Recent and Future Activity

During 2019, we expect to complete an estimated 290 to 320 gross (255 to 280 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2019 for drilling and infrastructure will be between $2.7 billion and $3.0 billion, consisting of $2.3 billion to $2.55 billion for horizontal drilling and completions including non-operated activity, $400.0 million to $450.0 million for midstream and infrastructure investments, excluding equity investments in long-haul pipelines or the cost of any leasehold and mineral rights acquisitions. During the year ended December 31, 2018, we drilled 189 gross (168 net) and completed 176 gross (155 net) operated horizontal wells. During the year ended December 31, 2018, our capital expenditures for drilling, completing and equipping wells were $1.4 billion. In addition, we spent $306.4 million for oil and gas midstream and infrastructure and $1.8 billion for leasehold and mineral rights acquisitions.

We are operating 21 rigs now and currently intend to operate between 18 and 22 rigs in 2019. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans in response to market conditions.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2018, 2017 and 2016 were prepared by Ryder Scott with respect to our assets and those of Viper. Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas that, 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2018 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 87% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 13% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent

reserve engineers periodically during the period covered by the reserve reports to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our Executive Vice President–Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Executive Vice President–Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 19 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;

- preparation of reserve estimates by our Executive Vice President–Reservoir Engineering or under his direct supervision;

- review by our Executive Vice President–Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;

- direct reporting responsibilities by our Executive Vice President–Reservoir Engineering to our Chief Executive Officer;

- verification of property ownership by our land department; and

- no employee's compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2018, 2017 and 2016 (including those attributable to Viper), based on the reserve reports prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

	December 31,		
	2018	2017	2016
Estimated proved developed reserves:			
Oil (MBbls)	403,051	141,246	79,457
Natural gas (MMcf)	705,084	190,740	105,399
Natural gas liquids (MBbls)	125,509	35,412	22,080
Total (MBOE)	646,074	208,447	119,104
Estimated proved undeveloped reserves:			
Oil (MBbls)	223,885	91,935	59,717
Natural gas (MMcf)	343,565	94,629	69,497
Natural gas liquids (MBbls)	64,782	19,198	15,054
Total (MBOE)	345,928	126,905	86,354
Estimated Net Proved Reserves:			
Oil (MBbls)	626,936	233,181	139,174
Natural gas (MMcf)	1,048,649	285,369	174,896
Natural gas liquids (MBbls)	190,291	54,609	37,134
Total (MBOE)[(1)]	992,001	335,352	205,458
Percent proved developed	65 %	62 %	58 %

(1) Estimates of reserves as of December 31, 2018, 2017 and 2016 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2018, 2017 and 2016, respectively, in accordance with SEC guidelines applicable to reserves estimates as of the end of such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological

interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A.“Risk Factors.” We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2018, our proved undeveloped reserves totaled 223,885 MBbls of oil, 343,565 MMcf of natural gas and 64,782 MBbls of natural gas liquids, for a total of 345,928 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table includes the changes in PUD reserves for 2018:

	(MBOE)
Beginning proved undeveloped reserves at December 31, 2017	126,905
Undeveloped reserves transferred to developed	(71,435)
Revisions	338
Net purchases	165,426
Extensions and discoveries	124,694
Ending proved undeveloped reserves at December 31, 2018	345,928

The increase in proved undeveloped reserves was primarily attributable to purchases of 165,426 MBOE mostly from the acquisition of Energen. Extensions contributed 111,020 MBOE from 138 gross (122 net) wells in which we have a working interest and 13,674 MBOE from 138 gross wells in which Viper owns royalty interests. Of the 138 gross working interest wells, 38 were in the Delaware Basin. Transfers of 71,435 MBOE were the result of drilling or participating in 89 gross (79 net) horizontal wells in which we have a working interest and 49 gross wells in which we have a royalty interest or mineral interest through Viper. We own a working interest in 45 of the 49 gross Viper wells. Upward revisions of 338 MBOE resulted from commodity price improvement and type curve performance.

Costs incurred relating to the development of PUDs were approximately $493.1 million during 2018. Estimated future development costs relating to the development of PUDs are projected to be approximately $1,201.7 million in 2019, $1,121.4 million in 2020, $435.1 million in 2021 and $127.0 million in 2022. Since our current executive team assumed management control in 2011, our average drilling costs and drilling times have been reduced. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

As of December 31, 2018, all of our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

As of December 31, 2018, less than 1.0% of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and natural gas liquids, all of which is from the Permian Basin in West Texas, and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Production Data:			
Oil (MBbls)	34,367	21,418	11,562
Natural gas (MMcf)	34,669	20,660	10,728
Natural gas liquids (MBbls)	7,465	4,056	2,399
Combined volumes (MBOE)	47,610	28,917	15,749
Daily combined volumes (BOE/d)	130,439	79,224	43,031
Average Prices:			
Oil (per Bbl)	$54.66	$48.75	$40.70
Natural gas (per Mcf)	1.76	2.53	2.10
Natural gas liquids (per Bbl)	25.47	22.20	14.20
Combined (per BOE)	44.73	41.02	33.47
Oil, hedged ($ per Bbl)[(1)]	51.20	48.94	40.80
Natural gas, hedged ($ per MMbtu)[(1)]	1.72	2.65	2.06
Average price, hedged ($ per BOE)[(1)]	42.20	41.26	33.54
Average Costs per BOE:			
Lease operating expense	$4.31	$4.38	$5.23
Production and ad valorem taxes	2.79	2.54	2.19
Gathering and transportation expense	0.55	0.44	0.74
General and administrative - cash component	0.79	0.80	1.03
Total operating expense - cash	$8.44	$8.16	$9.19
General and administrative - non-cash component	$0.57	$0.88	$1.68
Depreciation, depletion and amortization	13.09	11.30	11.30
Interest expense, net	1.83	1.40	2.58
Merger and integration expense	0.77	—	—
Total expenses	$16.26	$13.58	$15.56

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include realized gains and losses on cash settlements for commodity derivatives, which we do not designate for hedge accounting.

Productive Wells

As of December 31, 2018, we owned an average unweighted 64% working interest in 7,279 gross (4,678 net) productive wells and an average 0.5% royalty interest in 2,645 additional wells. Through our subsidiary Viper, we own an average unweighted 4.3% royalty or mineral interest in 3,448 productive wells. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of

producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage

The following table sets forth information as of December 31, 2018 relating to our leasehold acreage:

	Developed Acreage[1]		Undeveloped Acreage[2]		Total Acreage[3]	
Basin	Gross[4]	Net[5]	Gross[4]	Net[5]	Gross[4]	Net[5]
Conventional Permian	103,155	70,410	14,795	4,178	117,950	74,588
Delaware	127,819	90,554	104,324	79,651	232,143	170,205
Exploration	—	—	23,174	21,764	23,174	21,764
Midland	198,408	162,370	32,692	32,291	231,100	194,661
Total	429,382	323,334	174,985	137,884	604,367	461,218

(1) Developed acres are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) Does not include Viper's mineral interests but does include leasehold acres that we own underlying our mineral interests.

(4) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(5) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped acreage expirations

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2018, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2019		2020		2021		2022		2023	
Basin	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Delaware	43,963	31,130	13,779	6,474	7,447	3,447	—	—	—	—
Exploration	—	—	18,713	18,713	4,405	3,035	—	—	—	—
Midland	9,246	6,406	4,443	2,503	172	385	308	254	—	—
Total	53,209	37,536	36,935	27,690	12,024	6,867	308	254	—	—

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. Each of these wells was drilled in the Permian Basin of West Texas. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net