UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended **December 31, 2015** Commission File No. **0-22750**

ROYALE ENERGY, INC.
(Name of registrant in its charter)

California	**33-0224120**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3777 Willow Glen Drive
El Cajon, CA 92019
(Address of principal executive offices)

Issuer's telephone number: **619-383-6600**

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

Securities to be registered pursuant to Section 12(g) of the Act:
Common Stock, no par value per share
(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 o No x

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

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 during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-B is not contained herein, and will not be contained, to the best or 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer o	Smaller Reporting Company x

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

At June 30, 2015, the end of the registrant's most recently completed second fiscal quarter; the aggregate market value of common equity held by non-affiliates was $13,006,018.

At March 14, 2016, 17,616,663 shares of registrant's Common Stock were outstanding.

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ROYALE ENERGY, INC.
PART I

Item 1 Description of Business

Royale Energy, Inc. ("Royale Energy" or the "Company") is an independent oil and natural gas producer. Royale Energy's principal lines of business are the production and sale of natural gas, acquisition of oil and gas lease interests and proved reserves, drilling of both exploratory and development wells, and sales of fractional working interests in wells to be drilled by Royale Energy. Royale Energy was incorporated in California in 1986 and began operations in 1988. Royale Energy's common stock is traded on the Over-The-Counter QB (OTCQB) Market System (symbol ROYL). On December 31, 2015, Royale Energy had 15 full time employees.

Royale Energy owns wells and leases located mainly in the Sacramento Basin and San Joaquin Basin in California as well as in Utah, Texas, Oklahoma, Louisiana, and Alaska. Royale Energy usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Selling part of the working interest to others allows Royale Energy to reduce its drilling risk by owning a diversified inventory of properties with less of its own funds invested in each drilling prospect, than if Royale Energy owned all the working interest and paid all drilling and development costs of each prospect itself. Royale Energy generally sells working interests in its prospects to accredited investors in exempt securities offerings. The prospects are bundled into multi-well investments, which permit the third party investors to diversify their investments by investing in several wells at once instead of investing in single well prospects.

During its fiscal year ended December 31, 2015, Royale Energy continued to explore and develop natural gas properties with a concentration in California. Additionally, we own proved developed producing and non-producing reserves of oil and natural gas in Utah, Texas, Oklahoma and Louisiana, as well as prospective shale oil property in Alaska. In 2015, Royale Energy drilled two wells in northern California; one was commercially productive and one was a dry hole. We also drilled one commercially productive well and one dry hole in Texas. Royale Energy's estimated total reserves were approximately 2.5 and 4.1 BCFE (billion cubic feet equivalent) at December 31, 2015 and 2014, respectively. According to the reserve reports furnished by Netherland, Sewell & Associates, Inc., Royale Energy's independent petroleum engineers, the undiscounted net reserve value of its proved developed and undeveloped reserves was approximately $3.2 million at December 31, 2015, based on natural gas prices ranging from $2.59 per MCF to $2.98 per MCF. Netherland, Sewell & Associates, Inc. supplied reserve value estimates for the Company's California, Texas, Oklahoma, Utah and Louisiana properties.

Of course, net reserve value does not represent the fair market value of our reserves on that date, and we cannot be sure what return we will eventually receive on our reserves. Net reserve value of proved developed and undeveloped reserves was calculated by subtracting estimated future development costs, future production costs and other operating expenses from estimated net future cash flows from our developed and undeveloped reserves.

Our standardized measure of discounted future net cash flows at December 31, 2015, was estimated to be $1,559,716. This figure was calculated by subtracting our estimated future income tax expense from the net reserve value of proved developed and undeveloped reserves, and by further applying a 10% annual discount for estimated timing of cash flows. A detailed calculation of our standardized measure of discounted future net cash flow is contained in Supplemental Information about Oil and Gas Producing Activities – Changes in Standardized Measure of Discounted Future Net Cash Flow from Proved Reserve Quantities, page F-24.

Royale Energy reported a gain on turnkey drilling in connection with the drilling of wells on a "turnkey contract" basis in the amount of $2,330,969 and $1,640,731 for the years ended December 31, 2015 and 2014, respectively.

In addition to Royale Energy's own staff, Royale Energy hires independent contractors to drill, test, complete and equip the wells that it drills. Approximately 59.5% of Royale Energy's total revenue for the year ended December 31, 2015, came from sales of oil and natural gas from production of its wells in the amount of $1,018,928. In 2014, this amount was $2,598,297, which represented 80.7% of Royale Energy's total revenues.

Plan of Business

Royale Energy acquires interests in oil and natural gas reserves and sponsors private joint ventures. Royale Energy believes that its stockholders are better served by diversification of its investments among individual drilling prospects. Through its sale of joint ventures, Royale Energy can acquire interests and develop oil and natural gas properties with greater diversification of risk and still receive an interest in the revenues and reserves produced from these properties. By selling some of its working interest in most projects, Royale Energy decreases the amount of its investment in the projects and diversifies its oil and gas property holdings, to reduce the risk of concentrating a large amount of its capital in a few projects that may not be successful.

After acquiring the leases or lease participation, Royale Energy drills or participates in the drilling of development and exploratory oil and natural gas wells on its property. Royale Energy pays its proportionate share of the actual cost of drilling, testing, and completing the project to the extent that it retains all or any portion of the working interest.

Royale Energy also may sell fractional working interests in undeveloped wells to finance part of the drilling cost. A drilling contract that calls for a company to drill a well, for a fixed price, to a specified depth or geological formation is called a "turnkey contract." When Royale Energy sells fractional working interests in unproved property to raise capital to drill oil and natural gas wells, generally it agrees to drill these wells on a turnkey contract basis, so that the holders of the fractional interests prepay a fixed amount for the drilling and completion of a specified number of wells. Under a turnkey contract, Royale Energy may record a gain if total funds received to drill a well were more than the actual cost to drill those wells including costs incurred on behalf of the participants and costs incurred for its own account.

Although Royale Energy’s operating agreements do not usually address whether investors have a right to participate in subsequent wells in the same area of interest as a proposed well, it is the Company’s policy to offer to investors in a successful well the right to participate in subsequent wells at the same percentage level as their working interest investment in the prior successful well.

Our policy for turnkey drilling agreements is to recognize a gain on turnkey drilling programs after our obligations have been fulfilled, and a gain is only recorded when funds received from participants are in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account. See Note 1 to our Financial Statements, at page F-8.

Once drilling has commenced, it is generally completed within 10-30 days. See Note 1 to Royale Energy's Financial Statements, at page F-8. Royale Energy maintains internal records of the expenditure of each investor's funds for drilling projects.

Royale Energy generally operates the wells it completes. As operator, it receives fees set by industry standards from the owners of fractional interests in the wells and from expense reimbursements. For the year ended December 31, 2015, Royale Energy earned gross revenues from operation of the wells in the amount of $503,441 representing 29.4% of its total revenues for the year. In 2014, the amount was $464,429, which represented about 14.4% of total revenues. At December 31, 2015, Royale Energy operated 52 natural gas wells in California. Royale also has non-operating interests in three natural gas wells in Utah, twelve oil and gas wells in Texas, two in Oklahoma, one in California, and one in Louisiana.

Royale Energy currently sells most of its California natural gas production through PG&E pipelines to independent customers on a monthly contract basis, while some gas is delivered through privately owned pipelines to independent customers. Since many users are willing to make such purchase arrangements, the loss of any one customer would not affect our overall sales operations.

All oil and natural gas properties are depleting assets in which production naturally decreases over time as the finite amount of existing reserves are produced and sold. It is Royale Energy’s business as an oil and natural gas exploration and production company to continually search for new development properties. The Company’s success will ultimately depend on its ability to continue locating and developing new oil and natural gas resources. Natural gas demand and the prices paid for gas are seasonal. In recent years, natural gas demand and prices in Northern California have fluctuated unpredictably throughout the year.

Royale Energy had no subsidiaries in 2015 or 2014.

Competition, Markets and Regulation

Competition

The exploration and production of oil and natural gas is an intensely competitive industry. The sale of interests in oil and gas projects, like those Royale Energy sells, is also very competitive. Royale Energy encounters competition from other oil and natural gas producers, as well as from other entities that invest in oil and gas for their own account or for others, and many of these companies are substantially larger than Royale Energy.

Markets

Market factors affect the quantities of oil and natural gas production and the price Royale Energy can obtain for the production from its oil and natural gas properties. Such factors include: the extent of domestic production; the level of imports of foreign oil and natural gas; the general level of market demand on a regional, national and worldwide basis; domestic and foreign economic conditions that determine levels of industrial production; political events in foreign oil-producing regions; and variations in governmental regulations including environmental, energy conservation, and tax laws or the imposition of new regulatory requirements upon the oil and natural gas industry.

Regulation

Federal and state laws and regulations affect, to some degree, the production, transportation, and sale of oil and natural gas from Royale Energy's operations. States in which Royale Energy operates have statutory provisions regulating the production and sale of oil and natural gas, including provisions regarding deliverability. These statutes, along with the regulations interpreting the statutes, generally are intended to prevent waste of oil and natural gas, and to protect correlative rights to produce oil and natural gas by assigning allowable rates of production to each well or proration unit.

The exploration, development, production and processing of oil and natural gas are subject to various federal and state laws and regulations to protect the environment. Various federal and state agencies are considering, and some have adopted, other laws and regulations regarding environmental controls that could increase the cost of doing business. These laws and regulations may require: the acquisition of permits by operators before drilling commences; the prohibition of drilling activities on certain lands lying within wilderness areas or where pollution arises; and the imposition of substantial liabilities for pollution resulting from drilling operations, particularly operations in offshore waters or on submerged lands. The cost of oil and natural gas development and production also may increase because of the cost of compliance with such legislation and regulations, together with any penalties resulting from failing to comply with the legislation and regulations. Ultimately, Royale Energy may bear some of these costs.

Presently, Royale Energy does not anticipate that compliance with federal, state and local environmental regulations will have a material adverse effect on capital expenditures, earnings, or its competitive position in the oil and natural gas industry; however, changes in the laws, rules or regulations, or the interpretation thereof, could have a materially adverse effect on Royale Energy's financial condition or results of operation.

Royale Energy files quarterly, yearly and other reports with the Securities Exchange Commission. You may obtain a copy of any materials filed by Royale Energy with the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549, by calling 1-800-SEC-0300. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Royale Energy also provides access to its SEC reports and other public announcements on its website, http://www.royl.com.

Item 1A Risk Factors

In addition to the other information contained in this report, the following risk factors should be considered in evaluating our business.

We Depend on Market Conditions and Prices in the Oil and Gas Industry.

Our success depends heavily upon our ability to market oil and gas production at favorable prices. In recent decades, there have been both periods of worldwide overproduction and underproduction of hydrocarbons and periods of increased and relaxed energy conservation efforts. As a result the world has experienced periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis; these periods have been followed by periods of short supply of, and increased demand for, crude oil and, to a lesser extent, natural gas. The excess or short supply of oil and gas has placed pressures on prices and has resulted in dramatic price fluctuations.

Natural gas demand and the prices paid for gas are seasonal. The fluctuations in gas prices and possible new regulations create uncertainty about whether we can continue to produce gas for a profit.

Prices for oil and natural gas affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Any substantial and extended decline in the price of oil or natural gas would decrease our cash flows, as well as the carrying value of our proved reserves, our borrowing capacity and our ability to obtain additional capital.

The Price of Natural Gas

Large parts of our established production and reserves in California consist of natural gas. The price of natural gas has been volatile recently, and for 2015 the average sales price we received for natural gas was $2.75 per MCF, compared to $4.64 in 2014. The decrease in our natural gas production and the lower gas prices resulted in a 60.8% decrease in natural gas revenues in 2015 when compared to 2014. *See Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations for the Twelve Months Ended December 31, 2015, as Compared to the Twelve Months Ended December 31, 2014.*

Variance in Estimates of Oil and Gas Reserves could be Material.

The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, such estimates are inherently imprecise. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those estimated in reserve reports that we periodically obtain from independent reserve engineers.

You should not construe the standardized measure of proved reserves contained in our annual report as the current market value of the estimated proved reserves of oil and gas attributable to our properties. In accordance with Securities and Exchange Commission requirements, we have based the standardized measure of future net cash flows from the standardized measure of proved reserves on the average price during the 12-month period before the ending date of the period covered by the report, whereas actual future prices and costs may vary significantly. The following factors may also affect actual future net cash flows:

- the timing of both production and related expenses;
- changes in consumption levels; and
- governmental regulations or taxation.

In addition, the calculation of the standardized measure of the future net cash flows using a 10% discount as required by the Securities and Exchange Commission is not necessarily the most appropriate discount rate based on interest rates in effect from time to time and risks associated with our reserves or the oil and gas industry in general. Furthermore, we may need to revise our reserves downward or upward based upon actual production, results of future development, supply and demand for oil and gas, prevailing oil and gas prices and other factors.

Any significant variance in these assumptions could materially affect the estimated quantities and present value of our reserves. In addition, our standardized measure of proved reserves may be revised downward or upward, based upon production history, results of future exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Actual production, revenues, taxes, development expenditures and operating expenses with respect to our reserves will likely vary from the estimates used, and such variances may be material.

Future Acquisitions and Development Activities May Not Result in Additional Proved Reserves, and We May Not be Able to Drill Productive Wells at Acceptable Costs.

In general, the volume of production from oil and gas properties declines as reserves are depleted. Except to the extent that we acquire properties containing proved reserves or conduct successful development and exploration activities, or both, our proved reserves will decline as reserves are produced. Our future oil and gas production is, therefore, highly dependent upon our ability to find or acquire additional reserves.

The business of acquiring, enhancing or developing reserves is capital intensive. We require cash flow from operations as well as outside investments to fund our acquisition and development activities. If our cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be impaired.

The Oil and Gas Industry has Mechanical and Environmental Risks.

Oil and gas drilling and production activities are subject to numerous risks. These risks include the risk that no commercially productive oil or gas reservoirs will be encountered, that operations may be curtailed, delayed or canceled, and that title problems, weather conditions, compliance with governmental requirements, mechanical difficulties or shortages or delays in the delivery of drilling rigs and other equipment may limit our ability to develop, produce or market our reserves. New wells we drill may not be productive and we may not recover all or any portion of our investment in the well. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, our properties may be susceptible to hydrocarbon drainage from production by other operators on adjacent properties.

Industry operating risks include the risks of fire, explosions, blow outs, pipe failure, abnormally pressured formations and environmental hazards, such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, the occurrence of any of which could result in substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with customary industry practice, we maintain insurance for these kinds of risks, but we cannot be sure that our level of insurance will cover all losses in the event of a drilling or production catastrophe. Insurance is not available for all operational risks, such as risks that we will drill a dry hole, fail in an attempt to complete a well or have problems maintaining production from existing wells.

Drilling is a Speculative Activity Even with Newer Technology.

Assessing drilling prospects is uncertain and risky for many reasons. We have grown in the past several years by using 3-D seismic technology to acquire and develop exploratory projects in northern California, as well as by acquiring producing properties for further development. The successful acquisition of such properties depends on our ability to assess recoverable reserves, future oil and gas prices, operating costs, potential environmental and other liabilities and other factors.

Nevertheless, exploratory drilling remains a speculative activity. Even when fully utilized and properly interpreted, 3-D seismic data and other advanced technologies assist geoscientists in identifying subsurface structures but do not enable the interpreter to know whether hydrocarbons are in fact present. In addition, 3-D seismic and other advanced technologies require greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of these costs.

Therefore, our assessment of drilling prospects are necessarily imprecise and their accuracy inherently uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

Breaches of Contract by Sellers of Properties Could Adversely Affect Operations.

In most cases, we are not entitled to contractual indemnification for pre closing liabilities, including environmental liabilities, and we generally acquire interests in the properties on an "as is" basis with limited remedies for breaches of representations and warranties. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, the seller may not fulfill those obligations and leave us with the costs.

We May Not be Able to Acquire Producing Oil and Gas Properties Which Contain Economically Recoverable Reserves.

Competition for producing oil and gas properties is intense and many of our competitors have substantially greater financial and other resources than we do. Acquisitions of producing oil and gas properties may be at prices that are too high to be acceptable.

We Require Substantial Capital for Exploration and Development.

We make substantial capital expenditures for our exploration and development projects. We will finance these capital expenditures with cash flow from operations and sales of direct working interests to third party investors. We will need additional financing in the future to fund our developmental and exploration activities. Additional financing that may be required may not be available or continue to be available to us. If additional capital resources are not available to us, our developmental and other activities may be curtailed, which would harm our business, financial condition and results of operations.

Profit Depends on the Marketability of Production.

The marketability of our natural gas production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Most of our natural gas is delivered through natural gas gathering systems and natural gas pipelines that we do not own. Federal, state and local regulation of oil and gas production and transportation, tax and energy policies, and/or changes in supply and demand and general economic conditions could adversely affect our ability to produce and market its oil and gas. Any dramatic change in market factors could have a material adverse effect on our financial condition and results of operations.

We Depend on Key Personnel.

Our business will depend on the continued services of our executive officers, Jonathan Gregory, Chief Executive Officer, Donald H. Hosmer, President of Business Development and Stephen M. Hosmer, President and Chief Financial Officer. We do not have employment agreements with Jonathan Gregory, Donald or Stephen Hosmer. The loss of the services of any of these individuals would be particularly detrimental to us because of their background and experience in the oil and gas industry.

The Oil and Gas Industry is Highly Competitive.

The oil and gas industry is highly competitive in all its phases. Competition is particularly intense with respect to the acquisition of desirable producing properties, the acquisition of oil and gas prospects suitable for enhanced production efforts, and the hiring of experienced personnel. Our competitors in oil and gas acquisition, development, and production include the major oil companies in addition to numerous independent oil and gas companies, individual proprietors and drilling programs.

Many of our competitors possess and employ financial and personnel resources far greater than those which are available to us. They may be able to pay more for desirable producing properties and prospects and to define, evaluate, bid for, and purchase a greater number of producing properties and prospects than we can. We must compete against these larger companies for suitable producing properties and prospects, to generate future oil and gas reserves.

Governmental Regulations Can Hinder Production.

Domestic oil and gas exploration, production and sales are extensively regulated at both the federal and state levels. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, have legal authority to issue, and have issued, rules and regulations affecting the oil and gas industry which often are difficult and costly to comply with and which carry substantial penalties for noncompliance. State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states where we operate also have statutes and regulations governing conservation matters, including the unitization or pooling of properties. Our operations are also subject to numerous laws and regulations governing plugging and abandonment, discharging materials into the environment or otherwise relating to environmental protection. The heavy regulatory burden on the oil and gas industry increases its costs of doing business and consequently affects its profitability. Changes in the laws, rules or regulations, or the interpretation thereof, could have a materially adverse effect on our financial condition or results of operation.

Minority or Royalty Interest Purchases Do Not Allow Us to Control Production Completely.

We sometimes acquire less than the controlling working interest in oil and gas properties. In such cases, it is likely that these properties would not be operated by us. When we do not have controlling interest, the operator or the other co-owners might take actions we do not agree with and possibly increase costs or reduce production income in ways we do not agree with.

Environmental Regulations Can Hinder Production.

Oil and gas activities can result in liability under federal, state and local environmental regulations for activities involving, among other things, water pollution and hazardous waste transport, storage, and disposal. Such liability can attach not only to the operator of record of the well, but also to other parties that may be deemed current or prior operators or owners of the wells or the equipment involved. We have inspections performed on our properties to assure environmental law compliance, but inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

We may need to raise additional capital to continue operations.

We may require additional funding to complete our planned drilling activities. It may be necessary for us to raise additional capital to fund our drilling program or other operating capital needs through additional financing such as the sale of equity or debt securities in a public offering or through private placements of securities. We do not know if additional financing will be available when needed, or if it is available, whether it will be available on acceptable terms. Insufficient capital and liquidity may prevent or limit us from implementing our full business strategy.

Item 1B Unresolved Staff Comments

None

Item 2 Description of Property

Since 1993, Royale Energy has concentrated on development of properties in the Sacramento Basin and the San Joaquin Basin of Northern and Central California. In 2015, Royale Energy drilled two wells in northern California, one exploratory producing well and one exploratory dry hole. We also drilled two wells in Texas, one developmental producing and one developmental dry hole.

Following industry standards, Royale Energy generally acquires oil and natural gas acreage without warranty of title except as to claims made by, though, or under the transferor. In these cases, Royale Energy attempts to conduct due diligence as to title before the acquisition, but it cannot assure that there will be no losses resulting from title defects or from defects in the assignment of leasehold rights. Title to property most often carries encumbrances, such as royalties, overriding royalties, carried and other similar interests, and contractual obligations, all of which are customary within the oil and natural gas industry.

In December of 2013, Royale purchased an office building valued at $2,000,000, of which Royale paid $500,000 in cash on the date of purchase, and borrowed $1,500,000 from American West Bank, with a note secured by the property being purchased. The note carries an interest rate of 5.75% until paid in full with a balloon payment in 2024. On February 11, 2016, Royale Energy, Inc. entered into a purchase and sale agreement for the sale of its office building for $2.5 million. The buyer is currently conducting its due diligence process.

Following is a discussion of Royale Energy's significant oil and natural gas properties. Reserves at December 31, 2015, for each property discussed below, have been determined by Netherland, Sewell & Associates, Inc., registered professional petroleum engineers, in accordance with reports submitted to Royale Energy on February 1, 2016.

Northern California

Royale Energy owns lease interests in nine gas fields with locations ranging from Tehama County in the north to Kern County in the south, in the Sacramento and San Joaquin Basins in California. At December 31, 2015, Royale operated 52 wells in California with estimated total proven, developed, and undeveloped reserves at approximately 2.5 BCF, according to Royale's independently prepared reserve report as of December 31, 2015.

Developed and Undeveloped Leasehold Acreage

As of December 31, 2015, Royale Energy owned leasehold interests in the following developed and undeveloped properties in both gross and net acreage.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
California	7,261.26	4,355.47	8,016.62	7,223.19
Alaska	0.00	0.00	40,086.00	40,086.00
All Other States	5,331.63	2,011.62	8,540.97	4,988.80
Total	12,592.89	6,367.09	56,643.59	52,297.99

Gross and Net Productive Wells

As of December 31, 2015, Royale Energy owned interests in the following oil and gas wells in both gross and net acreage:

	Gross Wells	Net Wells
Natural Gas	62.00	27.93
Oil	9.00	1.48
Total	71.00	29.41

Drilling Activities

The following table sets forth Royale Energy's drilling activities during the years ended December 31, 2014 and 2015. All wells are located in the Continental U.S., in California, Texas, Louisiana and Utah.

Year	Type of Well(a)		Gross Wells(b)		Net Wells(e)	
		Total	Producing(c)	Dry(d)	Producing(c)	Dry(d)
2014	Exploratory	2	2	0	0.8734	0.0000
	Developmental	2	1	1	0.2173	0.3612
2015	Exploratory	2	1	1	0.5172	0.5243
	Developmental	2	1	1	0.3933	0.4725

a) An exploratory well is one that is drilled in search of new oil and natural gas reservoirs, or to test the boundary limits of a previously discovered reservoir. A developmental well is one drilled on a previously known productive area of an oil and natural gas reservoir with the objective of completing that reservoir.

b) Gross wells represent the number of actual wells in which Royale Energy owns an interest. Royale Energy's interest in these wells may range from 1% to 100%.

c) A producing well is one that produces oil and/or natural gas that is being purchased on the market.

d) A dry well is a well that is not deemed capable of producing hydrocarbons in paying quantities.

e) One "net well" is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as a whole number or a fraction.

Production

The following table summarizes, for the periods indicated, Royale Energy's net share of oil and natural gas production, average sales price per barrel (BBL), per thousand cubic feet (MCF) of natural gas, and the MCF equivalent (MCFE) for the barrels of oil based on a 6 to 1 ratio of the price per barrel of oil to the price per MCF of natural gas. "Net" production is production that Royale Energy owns either directly or indirectly through partnership or joint venture interests produced to its interest after deducting royalty, limited partner or other similar interests. Royale Energy generally sells its oil and natural gas at prices then prevailing on the "spot market" and does not have any material long term contracts for the sale of natural gas at a fixed price.

	2015	2014
Net volume		
Oil (BBL)	403	685
Gas (MCF)	363,168	547,898
MCFE	365,586	552,008
Average sales price		
Oil (BBL)	$ 46.11	$ 85.20
Gas (MCF)	$ 2.75	$ 4.64
Net production costs and taxes	$ 1,000,769	$ 1,427,673
Lifting costs (per MCFE)	$ 2.74	$ 2.59

Net Proved Oil and Natural Gas Reserves

As of December 31, 2015, Royale Energy had proved developed reserves of 2,174 MMCF and total proved reserves of 2,511 MMCF of natural gas on all of the properties Royale Energy leases. For the same period, Royale Energy also had no proved developed oil and natural gas liquid combined reserves.

Oil and gas reserve estimates and the discounted present value estimates associated with the reserve estimates are based on numerous engineering, geological and operational assumptions that generally are derived from limited data.

Item 3 Legal Proceedings

Royale Energy, Inc. vs. Rampart Alaska LLC, Superior Court, Nome, Alaska. On November 14, 2014, Royale Energy, Inc. caused a complaint for lien foreclosure to be filed in the Superior Court for the State of Alaska, Second Judicial District at Nome. Royale Energy caused certain liens to be filed against the working interests of Rampart Alaska LLC involving oil leases on the North Slope Alaska. The filing of the liens came about as the result of Rampart's failure to reimburse for joint interest billings and cash calls. Royale sought in the litigation to foreclose the liens to recover the sums secured thereby or the working interests themselves. Rampart Alaska answered the complaint and asserted a counterclaim against Royale for damages alleging breach of contract, violation of the covenant of good faith and fair dealing, unjust enrichment, defamation, violations of the Alaska Securities Act and seeking to undo the filing of the lien claims. Stephen Hosmer, as an officer of Royale, was also independently named as a third party defendant by Rampart for claims arising out of defamation and violation of the Alaska Securities Act. On September 25, 2015, Royale and Rampart Alaska, LLC entered into a settlement agreement in which Rampart assigned its interest in the Property to Royale, and Rampart received cash and a note totaling $500,000. The note was subsequently repaid in November 2015 when Royale Energy sold the property, and the litigation between the parties has been concluded.

Hemco Development LLC vs. Royale Energy, Inc., et al, 44th Judicial District, Dallas County, Texas, Case No. DC-15-10958. On September 14, 2015, Hemco Development, LLC ("Hemco") filed a complaint, asserting that the Company owed Hemco $451,080.10 for the Company's share of operating costs. While this amount is already included in its Accounts Payable, the Company disputes that this amount is owed or that the claimed costs were properly incurred. The Company has answered the complaint and intends to vigorously defend the lawsuit.

Item 4 Mine Safety Disclosures

Not Applicable

PART II

Item 5 Market for Common Equity and Related Stockholder Matters

Royale Energy's Common Stock is traded under the symbol "ROYL". Since January 21, 2016, Royale Energy's Common Stock has been traded on the OTC QB Market. Prior to that, Royale energy's Common Stock was traded on the Nasdaq Stock Market. As of December 31, 2015, 16,396,579 shares of Royale Energy's Common Stock were held by approximately 6,008 stockholders. The following table reflects the high and low quarterly closing sales prices on the Nasdaq Stock Market from January 2014 through December 2015.

	1st Qtr		2nd Qtr		3rd Qtr		4th Qtr	
	High	Low	High	Low	High	Low	High	Low
2014	3.13	2.53	3.57	2.70	4.78	2.69	2.79	2.02
2015	2.16	1.55	1.82	1.15	1.27	0.63	0.81	0.30

Dividends

The Board of Directors did not issue cash or stock dividends in 2015 or 2014.

Recent Sales of Unregistered Securities

None.

Item 6 Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with Royale Energy's Financial Statements and Notes thereto and other financial information relating to Royale Energy included elsewhere in this document.

For the past twenty-three years, Royale Energy has primarily acquired and developed producing and non-producing natural gas properties in California. In 2004, Royale Energy began developing leases in Utah and in 2012 began acquiring leases in Alaska. The most significant factors affecting the results of operations are (i) the change in commodities price of natural gas and oil reserves owned by Royale Energy, (ii) changes in oil and natural gas production levels and reserves, and (iii) turnkey drilling activities.

Critical Accounting Policies

Revenue Recognition

Royale's primary business is oil and gas production. Natural gas flows from the wells into gathering line systems, which are equipped occasionally with compressor systems, which in turn flow into metered transportation and customer pipelines. Monthly, price data and daily production are used to invoice customers for amounts due to Royale Energy and other working interest owners. Royale Energy operates most of its own wells and receives industry standard operator fees.

Royale Energy generally sells crude oil and natural gas under short-term agreements at prevailing market prices. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured.

Revenues from the production of oil and natural gas properties in which the Royale Energy has an interest with other producers are recognized on the basis of Royale Energy's net working interest. Differences between actual production and net working interest volumes are not significant.

Royale Energy's financial statements include its *pro rata* ownership of wells. Royale Energy usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Royale Energy generally retains about a 50% working interest. All results, successful or not, are included at its pro rata ownership amounts: revenue, expenses, assets, and liabilities as defined in FASB ASC 932-323-25 and 932-360.

Oil and Gas Property and Equipment

Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Interest costs, to the extent they are incurred to finance expenditures during the construction phase, are included in property, plant and equipment and are depreciated over the service life of the related assets.

Royale Energy uses the “successful efforts” method to account for its exploration and production activities. Under this method, Royale Energy accumulates its proportionate share of costs on a well-by-well basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred, and capitalizes expenditures for productive wells. Royale Energy amortizes the costs of productive wells under the unit-of-production method.

Royale Energy carries, as an asset, exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where Royale Energy is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain Royale Energy’s wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Proved oil and gas properties held and used by Royale Energy are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

Royale Energy estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated evaluation assumptions for crude oil commodity prices. Annual volumes are based on field production profiles, which are also updated annually. Prices for natural gas and other products are based on assumptions developed annually for evaluation purposes.

Impairment analyses are generally based on proved reserves. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value. During 2015 and 2014, impairment losses of $424,163 and $268,093, respectively, were recorded on various capitalized lease and land costs where the carrying value exceeded the fair value or where the leases were no longer viable.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that Royale Energy expects to hold the properties. The valuation allowances are reviewed at least annually.

Upon the sale or retirement of a complete field of a proved property, Royale Energy eliminates the cost from its books, and the resultant gain or loss is recorded to Royale Energy’s Statement of Operations. Upon the sale of an entire interest in an unproved property where the property has been assessed for impairment individually, a gain or loss is recognized in Royale Energy’s Statement of Operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a recovery of the cost in the interest retained with any excess funds recognized as a gain. Should Royale Energy’s turnkey drilling agreements include unproved property, total drilling costs incurred to satisfy its obligations are recovered by the total funds received under the agreements. Any excess funds are recorded as a Gain on Turnkey Drilling Programs, and any costs not recovered are capitalized and accounted for under the “successful efforts” method.

Royale Energy sponsors turnkey drilling agreement arrangements in unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as Deferred Drilling Obligations, and then reduced as costs to complete its obligations are incurred with any excess booked against its property account to reduce any basis in its own interest. Gains on Turnkey Drilling Programs represent funds received from turnkey drilling participants in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account; and are recognized only upon making this determination after Royale's obligations have been fulfilled.

The contracts require the participants pay Royale Energy the full contract price upon execution of the agreement. Royale Energy completes the drilling activities typically between 10 and 30 days after drilling begins. The participant retains an undivided or proportional beneficial interest in the property, and is also responsible for its proportionate share of operating costs. Royale Energy retains legal title to the lease. The participants purchase a working interest directly in the well bore.

In these working interest arrangements, the participants are responsible for sharing in the risk of development, but also sharing in a proportional interest in rights to revenues and proportional liability for the cost of operations after drilling is completed.

Since the participant's interest in the prospect is limited to the well, and not the lease, the investor does not have a legal right to participate in additional wells drilled within the same lease. However, it is the Company's policy to offer to participants in a successful well the right to participate in subsequent wells at the same percentage level as their working interest investment in the prior successful well with similar turnkey drilling agreement terms.

A certain portion of the turnkey drilling participant's funds received are non-refundable. The company records a liability for all funds invested as deferred drilling obligations until each individual well is complete. Occasionally, drilling is delayed due to the permitting process or drilling rig availability. At December 31, 2015 and 2014, Royale Energy had deferred drilling obligations of $8,415,528 and $7,937,786 respectively.

If Royale Energy is unable to drill the wells, and a suitable replacement well is not found, Royale would retain the non-refundable portion of the contract and return the remaining funds to the participant. Included in cash and cash equivalents are amounts for use in completion of turnkey drilling programs in progress.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to 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 revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, plant products and gas reserve volumes and the future development costs. Actual results could differ from those estimates.

Deferred Income Taxes

Deferred income taxes reflect the net tax effects, calculated at currently enacted rates, of (a) future deductible/taxable amounts attributable to events that have been recognized on a cumulative basis in the financial statements or income tax returns, and (b) operating loss and tax credit carry forwards. All available evidence, both positive and negative, must be considered to determine whether, based on the weight of that evidence, a valuation allowance for deferred tax assets is needed. The Company uses information about the Company's financial position and its results of operations for the current and preceding years.

The Company must use its judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence is commensurate with the extent to which it can be objectively verified. The more negative evidence that exists, the more positive evidence is necessary and the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. A cumulative loss in recent years is a significant piece of negative evidence that is difficult to overcome.

Future realization of a tax benefit sometimes will be expected for a portion, but not all, of a deferred tax asset, and the dividing line between the two portions may be unclear. In those circumstances, application of judgment based on a careful assessment of all available evidence is required to determine the portion of a deferred tax asset for which it is more likely than not a tax benefit will not be realized.

Results of Operations for the Twelve Months Ended December 31, 2015, as Compared to the Twelve Months Ended December 31, 2014

For the year ended December 31, 2015, we recorded a net loss of $2,010,816, a $141,040 improvement when compared to net loss of $2,151,856 during 2014. Total revenues from operations in 2015 were $1,713,088, a decrease of $1,508,410, or 46.8% from the total revenues of $3,221,498 in 2014, due to lower natural gas production and the industry wide decrease in commodity prices during 2015. Total expenses for operations in 2015 were $6,937,741, a decrease of $337,590, or 4.6%, from the total expenses of $7,275,331 in 2014, due mainly to decreases in lease operating expenses and delay rental costs.

In 2015, revenues from oil and gas production decreased by 60.8% to $1,018,928 from $2,598,297 in 2014. This decrease was due to lower production volumes and lower natural gas commodity prices received during 2015. The net sales volume of natural gas for the year ended December 31, 2015, was approximately 363,168 MCF with an average price of $2.75 per MCF, versus 547,898 MCF with an average price of $4.64 per MCF for 2014. This represents a decrease in net sales volume of 184,730 MCF or 33.7%. This decrease in production volume was mainly due to the natural declines in our wells. The net sales volume for oil and condensate (natural gas liquids) production was approximately 403 barrels with an average price of $46.11 per barrel for the year ended December 31, 2015, compared to 685 barrels at an average price of $85.20 per barrel for the year in 2014. This represents a decrease in net sales volume of 282 barrels, or 41.2%, also due to the natural declines on existing oil and condensate wells. Northern and central California accounted for approximately 98% of the Company's successful natural gas production in 2015.

Oil and natural gas lease operating expenses decreased by $426,904, or 29.9% to $1,000,769 for the year ended December 31, 2015, from $1,427,673 for the year in 2014. This decrease was due to lower plugging and abandonment costs and workover related costs in 2015. During 2014, two wells that were plugged and abandoned had much higher costs than anticipated. In addition, we had more workover activity in 2014 as we attempted to increase production on various wells. When measuring lease operating costs on a production or lifting cost basis, in 2015, the $1,000,769 equates to a $2.74 per MCFE lifting cost versus a $2.59 per MCFE lifting cost in 2014, a 5.8% increase, due to lower production volumes. Delay rental costs decreased by $168,493 or 27.3%, to $448,313 for the year in 2015 from $616,806 in 2014. This decrease was due to lower costs related to our ownership of our Alaska leases, some of which we chose not to renew and a portion of which was sold during 2015.

At December 31, 2015, Royale Energy had a deferred drilling obligation of $8,415,528. During 2015, we disposed of $4,955,734 of obligations relating to 2014, upon completing the drilling of four wells – two exploratory and two developmental. Additionally we purchased an interest in an existing well from an industry partner. In 2015, we also recorded a gain of $564,346 on accounts payable invoices in dispute as the vendor went into bankruptcy, and under the opinion of legal counsel, these invoices were deemed no longer payable. This resulted in a gain of $2,330,969. During 2014, we disposed of $4,172,296 of obligations relating to 2013, upon completing the drilling of four wells, two exploratory and two developmental, in addition to participating in the drilling of one additional well with an industry partner. There was also an adjustment of approximately $550,000 of accrued costs on a well where the additional work would no longer prove viable. These factors resulted in a gain of $1,640,731. Royale Energy expects to dispose of approximately $3.4 million of its deferred drilling obligation in the first six months of 2016 with $5.5 million of its deferred drilling obligation disposed of by the end of 2016.

During 2015, we recorded a gain of $468,759 related to the sale of a portion of our western block oil and gas lease acreage in Alaska. During this period, we also recorded a gain of $87,127 on the settlement of accounts payable due to vendors. In 2015, we also recorded a gain of $403,000 on the sale of a license agreement to our Alaska seismic survey. Additionally in 2015, we recorded a gain of $10,070 on the sale of a Company owned condominium located in San Diego, California. During 2015, we recorded a write down of $60,960 on certain oil and gas well equipment to its current estimated market value. During 2014, we recorded a gain of $369,977 on the sale of certain oil and natural gas leases in Utah. In 2014, we also recorded a loss of $34,601 on previously capitalized office leasehold improvements due to our office relocation.

Impairment losses of $424,163 and $268,093 were recorded in 2015 and 2014, respectively. In 2015, $327,727 of the impairment loss was due to two Utah wells, one Louisiana well, and our remaining Alaska acreage where the carrying value exceeded the fair value. In 2014, $217,629 of the impairment loss was due to two Utah wells where the carrying value exceeded the fair value. For the balance of the loss in 2015 and the 2014, we recorded impairments on various capitalized lease and land costs that were no longer viable.

Bad debt expense for 2015 and 2014 were $536,538 and $653,133, respectively. The expenses in 2015 and 2014 arose from identified uncollectable receivables relating to our oil and natural gas properties either plugged and abandoned or scheduled for plugging and abandonment and our year-end oil and natural gas reserve values. We periodically review our accounts receivable from working interest owners to determine whether collection of any of these charges appears doubtful. By contract, the Company may not collect some charges from its Direct Working Interest owners for certain wells that ceased production or had been sold during the year, to the extent that these charges exceed production revenue.

The aggregate of supervisory fees and other income was $694,160 for the year ended December 31, 2015, an increase of $70,959 or 11.4% from $623,201 during the year in 2014. This increase was mainly due to lower costs in 2015 associated with pipeline and compressor fees due to costs to rebuild a compressor in one of our main fields during 2014. Supervisory fees are charged in accordance with the Council for Petroleum Accountants Societies (COPAS) policy for reimbursement of expenses associated with the joint accounting for billing, revenue disbursement, and payment of taxes and royalties. These charges are reevaluated each year and adjusted up or down as deemed appropriate by a published report to the industry by Ernst & Young, LLP, Certified Public Accountants. Supervisory fees increased $39,012 or 8.4%, to $503,441 in 2015 from $464,429 in 2014.

Depreciation, depletion and amortization expense increased to $400,813 from $315,574 an increase of $85,239 or 27.0% for the year ended December 31, 2015, as compared to 2014. The depletion rate is calculated using production as a percentage of reserves. This increase in depreciation expense was mainly due to a higher depletion rate as reserve volumes were lower at the end of 2015.

General and administrative expenses increased slightly by $19,458 or 0.6%, to $3,181,571 for the year ended December 31, 2015, from $3,162,113 for the year in 2014. This increase was primarily due to higher market fees relating to its market equity offering issuances. Legal and accounting expense increased to $558,471 for the year, compared to $401,160 for 2014, a $157,311 or 39.2% increase. The increased expense was the result of higher legal fees primarily related to the Rampart litigation, which was settled at the end of 2015.

Marketing expense for the year ended December 31, 2015, decreased $104,636 or 24.3%, to $326,143, compared to $430,779 for the year in 2014. The decrease was due to higher broker fees paid in 2014 as we used an outside broker to sell direct working interests to investors.

During 2015, interest expense increased to $86,088 from $81,605 in 2014, a $4,483 or 5.5% increase. This increase resulted from interest paid on the outstanding loan for the corporate headquarters. Further details concerning Royale's notes payable can be found in *Capital Resources and Liquidity*, below.

In 2015 and 2014, we did not have an income tax expense due to the use of a percentage depletion carryover valuation allowance created from the current and past operations resulting in an effective tax rate less than the normal federal rate of 34% plus the relevant state rates (mostly California, 9.3%).

Capital Resources and Liquidity

At December 31, 2015, Royale Energy had current assets totaling $4,406,983 and current liabilities totaling $11,383,282, a $6,976,299 working capital deficit. We had cash and cash equivalents at December 31, 2015 of $3,763,819 compared to $3,061,841 at December 31, 2014.

Ordinarily, we fund our operations and cash needs from our available credit and cash flows generated from operations. We believe that for the foreseeable future we will be able to meet our liquidity demands through cash flow or financing activities, including ongoing operations as the Company continues to increase its well inventory or additional sales of equity or debt securities.

At December 31, 2015, our other receivables, which consist of receivables from direct working interest investors and industry partners, totaled $381,192, compared to $1,760,181 at December 31, 2014, a $1,378,989 or 78.3% decrease. This was primarily due to the litigation settlement with an industry partner, which removed approximately $1,200,000 in other receivables at year end 2015. Royale's revenue receivable at the end of 2015 was $147,936, a decrease of $345,359 or 70.0%, compared to $493,295 at the end of 2014, due to lower oil and gas production and commodity prices. At December 31, 2015, our accounts payable and accrued expenses totaled $2,937,226, a decrease of $1,565,333 or 34.8% over the accounts payable at the end of 2014 of $4,502,559, mainly due to lower trade accounts payable at the end of 2015.

In May 2015, we entered into a sales agreement with Roth Capital, LLC (Roth) relating to the sale of shares of our common stock. Pursuant to the sales agreement, we sold 701,397 shares of common stock to the public for $556,123 in 2015. In October 2015, we discontinued such sales and the sales agreement was terminated.
On November 25, 2015, we entered into a securities purchase agreement and related agreements with a group of individual investors pursuant to a registered direct offering. Under the terms of the agreements, the investors purchased 497,948 shares of Royale's common stock at $0.408 per share, and received warrants to purchase up to 248,973 shares (the "Warrants') of stock at $1.00 per share for three (3) years, for a total of $203,165 in gross proceeds,. Each Warrant becomes exercisable one year from the date of issuance. Each Warrant contains customary adjustments for corporate events such as reorganizations, splits, and dividends.

In December of 2013, Royale purchased an office building valued at $2,000,000, of which $500,000 was paid in cash on the date of purchase, and $1,500,000 was borrowed from AmericanWest Bank, with a note secured by the property being purchased. The note carries an interest rate of 5.75% until paid in full. Royale will pay this loan in 119 regular payments of $9,525 each and one balloon payment estimated at $1,150,435. Royale's final payment will be due on January 1, 2024, and will be for all principal and all accrued interest not yet paid. Payments include principal and interest. Stephen M Hosmer, President and CFO is named as a personal guarantor of the loan. At December 31, 2015, the outstanding balance of this note was $1,446,853. The loan agreement contains certain covenants that, among other things, Royale must maintain a ratio of EBITDA-Debt Service Coverage in excess of 1.50 to 1.00. At December 31, 2015, Royale was not in compliance with this covenant, but obtained a forbearance from the bank from terms of that covenant. On February 11, 2016, Royale Energy entered into a purchase and sale agreement for the sale of the office building for $2.5 million. The buyer is currently conducting their due diligence process prior to completion of the sale.

We do not engage in hedging activities or use derivative instruments to manage market risks.

The following schedule summarizes our known contractual cash obligations at December 31, 2015, and the effect such obligations are expected to have on our liquidity and cash flow in future periods.

	Total Obligations	2016	2017-2018	2019	Beyond
Building Purchase Note	$ 2,064,842	$ 114,301	$ 228,602	$ 114,301	$ 1,607,638

Operating Activities. For the years ended December 31, 2015 and 2014, cash used by operating activities totaled $3,495,438 and $3,151,949, respectively. This $343,489 increase in cash used was mainly due to the decrease in our trade accounts payable during the year in 2015, through a combination of payments and settlements with our vendors.

Investing Activities. For the year ended December 31, 2015 and 2014, cash provided by investing activities was $3,537,137 and $1,359,673, respectively. This $2,177,464 increase in cash provided in 2015 was primarily due to the sale of a portion of our leases in Alaska, from which we received proceeds of approximately $1.4 million. In 2015, we also received approximately $400,000 from the sale of a license agreement to our Alaska seismic survey and we received proceeds of approximately $500,000 from the sale of the company owned condominium located in San Diego, California. Additionally, our turnkey drilling program proceeds and expenditures were higher in 2015, when we drilled four wells and purchased an interest in an existing well, while in 2014 we drilled four wells and participated in the drilling of one well. The wells drilled in 2015 were higher in costs due to their locations and depths.

Financing Activities. Net cash provided by financing activities totaled $660,279 and net cash used by financing activities was $24,116 for the years ended December 31, 2015 and 2014, respectively. This difference was mainly due to the proceeds received during 2015 for common stock sales. During 2015, Royale issued 701,397 shares of its common stock and received net proceeds of $534,274 in a registered market equity offering program. Also in 2015, we received net proceeds of $153,876 and issued 485,486 shares of its common stock and 242,746 additional warrants in a registered direct offering. These proceeds were added to working capital and used for ordinary operating expense. In 2015 and 2014, cash used from financing activities was used in principal payments from the loan used to finance the purchase of our corporate headquarters.

Changes in Reserve Estimates

During 2015, our overall proved developed and undeveloped reserves decreased by 39% and our previously estimated proved developed and undeveloped reserve quantities were revised downward by approximately 1.3 million cubic feet of natural gas. This downward revision was primarily due to seven California wells and one Utah well, which had lower than previously estimated proved producing and non-producing natural gas reserves. See Supplemental Information about Oil and Gas Producing Activities (Unaudited), page F-20.

During 2014, our overall proved developed and undeveloped reserves increased by 6% and our previously estimated proved developed and undeveloped reserve quantities were revised downward by approximately 0.1 million cubic feet of natural gas. This downward revision was primarily due to two California wells, one drilled in 2013 and the other drilled in 2014, which had lower than previously estimated proved producing and proved undeveloped natural gas reserves. See Supplemental Information about Oil and Gas Producing Activities (Unaudited), page F-20.

Item 7 Qualitative and Quantitative Disclosures About Market Risk

Royale Energy is exposed to market risk from changes in commodity prices and in interest rates. In 2015, we sold a majority of our natural gas at the daily market rate through the Pacific Gas & Electric pipeline. In 2015, our natural gas revenues were approximately $1.0 million with an average price of $2.75 per MCF. At current production levels, a 10% per MCF increase or decrease in our average price received could potentially increase or decrease our natural gas revenues by approximately $100,000. At our current production levels of oil and natural gas condensate, a 10% increase or decrease in our average price per barrel could potentially increase or decrease our oil and natural gas revenues by approximately $2,000. We currently do not sell any of our natural gas or oil through hedging contracts.

Item 8 Financial Statements and Supplementary Data

See pages F-1, et seq., included herein.

Item 9 Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A Controls and Procedures

Disclosure Controls

Disclosure controls are controls and other procedures that are designed to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Our disclosure controls and procedures are designed to insure that the information required to be filed is accumulated and communicated to our management in a manner designed to enable them to make timely decisions regarding required disclosure.

Our executive officers, Jonathan Gregory, Chief Executive Officer, Donald H. Hosmer, President of Business Development and Stephen M. Hosmer, President and Chief Financial Officer, evaluated the effectiveness or our disclosure controls and procedures as of the end of the 2015 fiscal year. Based on their evaluation, they concluded that our disclosure controls are effective as of December 31, 2015.

Management Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements. Management assessed our internal control over financial reporting as of December 31, 2015, which was the end of our fiscal year. Management based its assessment on criteria established in the SEC Commission Guidance Regarding Management's Report on Internal Control Over Financial Reporting Under Section 13(a) or 15(d) of the Securities Exchange Act of 1934. The guidance sets forth an approach by which management can conduct a top-down, risk-based evaluation of internal control over financial reporting. Management's assessment included an evaluation of risks to reliable financial reporting, whether controls exist to address those risks and evaluated evidence about the operation of the controls included in the evaluation based on its assessment of risk.

Based on our assessment, management has concluded that our internal control over financial reporting was effective as of the end of the fiscal year to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles. We reviewed the results of management's assessment with the Audit Committee of our Board of Directors.

This annual report does not include an attestation report of the company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the company's registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the company to provide only management's report in this annual report.

Changes in Internal Control over Financial Reporting

No changes in our internal control over financial reporting occurred during the last fiscal quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls

Our management, including our CEO and CFO, does not expect that our disclosure controls or internal controls over financial reporting will prevent all error or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, but not absolute, assurance that the objectives of a control system are met. Any control system contains limitations imposed by resources and relevant cost considerations. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues have been addressed. These inherent limitations include the realities that judgments can be faulty and that breakdowns can occur because of simple error or mistake. In addition, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of a control. Our control system design is also based on assumptions about the likelihood of future events, and we cannot be sure that we have considered all possible future circumstances and events.

PART III

Item 10 Directors and Executive Officers of the Registrant

All of our directors serve one year terms from the time of their election to the time their successor is elected and qualified. The following information is furnished with respect to each director and executive officer who served as such during the fiscal year ended December 31, 2015:

Name	Age	First Became Director or Executive Officer	Positions Held
Harry E. Hosmer	85	1986	Chairman of the Board
Donald H. Hosmer	61	1986	President of Business Development and Director
Stephen M. Hosmer	49	1996	President, Chief Financial Officer, Secretary, and Director
Ronald B Verdier (1) (3)	74	2015	Director
Jonathan Gregory	51	2014	Chief Executive Officer and Director
Gary Grinsfelder (1) (2) (3)	66	2007	Director
Ronald Buck (1) (2) (3)	80	2015	Director

(1) Member of the audit committee.
(2) Member of the compensation committee.
(3) Member of the nominations committee.

The board has determined that directors Gary Grinsfelder, Ronald Buck, and Ronald Verdier qualify as independent directors.

The following summarizes the business experience of each director and executive officer for the past five years.

Harry E. Hosmer – Chairman of the Board

Harry E. Hosmer has served as chairman since Royale Energy began in 1986, and from inception in 1986 until June 1995, he also served as president and chief executive officer.

Jonathan Gregory – Chief Executive Officer and Director

Mr. Gregory was appointed Royale's chief executive officer on September 10, 2015. Mr. Gregory has previously served as chief financial officer for private independent exploration and production companies, where he was actively engaged in multiple debt and equity financings, and overseeing acquisition and development activities. Mr. Gregory has over 20 years of oil and gas reserve based lending experience. Mr. Gregory is a member of Houston Energy Finance Group; and ADAM Houston Energy Network. He is also a Co-Founder of Bread of Life, Inc., a non-profit organization committed to empowering homeless Houstonians; and a past director of Small Steps Nurturing Center, a non-profit Christian organization that provides early childhood education for economically at-risk children in the inner-city of Houston, Texas. Mr. Gregory graduated from Lamar University in 1986 with a Bachelors degree in Finance.

Donald H. Hosmer – President of Business Development and Director

Donald H. Hosmer has served as an executive officer and director of Royale Energy since its inception in 1986. In June 1995 he became president and chief executive officer. In October 2008, he became co-president and co-chief executive officer, with primary responsibility for marketing and investor/shareholder relations for the company. Donald H. Hosmer is the son of Harry E. Hosmer and brother of Stephen M. Hosmer.

Stephen M. Hosmer – President, Chief Financial Officer, Secretary, and Director

Stephen M. Hosmer joined Royale Energy as the management information systems manager in May 1988, responsible for developing and maintaining Royale Energy's computer software. Mr. Hosmer developed programs and software systems used by Royale Energy. From 1991 to 1995, he served as president of Royale Operating Company, Royale Energy's operating subsidiary. In 1995, he became chief financial officer of Royale Energy. In 1996, he was elected to the board of directors of Royale Energy. In 2003, he was elected executive vice president. In October 2008, he became co-president and co-chief executive officer with primary responsibility for oil and gas exploration operations. Mr. Hosmer served seven years on the board of directors of Youth for Christ, a charitable organization in San Diego, California. He currently serves on the board of Venture Expeditions (www.ventureexpeditions.org), a charitable organization based in Minneapolis MN. Stephen M. Hosmer is the son of Harry E. Hosmer and brother of Donald H. Hosmer. Mr. Hosmer holds a Bachelor of Science degree in Business Administration from Oral Roberts University in Tulsa, Oklahoma, as well as earning his MBA degree via the prestigious President/Key Executive program at Pepperdine University in Malibu, California.

Gary Grinsfelder – Director

Mr. Grinsfelder is a geologist and manager with 38 years' experience in oil and gas exploration, exploitation and property evaluation. Currently Mr. Grinsfelder is an independent industry consultant. Previously, Mr. Grinsfelder was Vice President of Exploration at LeFrak Energy and President of TXCO Resources. He has also served in geologic and management roles for Output Exploration, LLC, Araxas Exploration, Inc., Triad Energy Corporation, Spartan Petroleum Corporation, American Petrofina Company of Texas, Union Oil Company of California and Degolyer and MacNaughton. He received a Bachelor of Science degree in 1972 from Southern Methodist University and has performed graduate studies at the University of Puerto Rico Department of Marine Science and University of Houston Department of Geology.

Ronald B Verdier

Mr. Verdier was appointed to the board in 2015 following the resignation of Tony Hall. Mr. Verdier is a retired banker who began his career in banking in 1968. He served as an employee and officer of Mercantile Trust & Savings Bank, Quincy, Illinois, for thirty-three years, ending as Senior Vice President. In 2002, Mr. Verdier retired from Mercantile Trust & Savings Bank and became President of Hannibal National Bank, Hannibal Missouri, where he served until his retirement in 2012. Mr. Verdier is a graduate of the School of Banking at the University of Wisconsin, Madison, and of the School of Banking at the University of Oklahoma. Based on his qualifications, the board of directors has designated Mr. Verdier as an audit committee financial expert.

Ronald L. Buck

Mr. Buck was elected to the board in 2015. Mr. Buck received a Bachelor of Science degree in Marketing and a Minor in Geology and Economics from Northwestern University. After building his business into a large scale distribution company, he sold the company to his two sons in 1992. Since 1992 he has been in finance and managing family assets including oil and gas wells and oil gathering pipeline investments. In this capacity, he also travels extensively to financial meetings and is a member of the National Association of Financial Advisors.

Audit Committee

The board has appointed an audit committee to assist the board of directors in carrying out its responsibility as to the independence and competence of the Company's independent public accountants. All members of the audit committee are independent members of the board of directors. The audit committee operates pursuant to an audit committee charger, which has been adopted by the board of directors to define the committee's responsibilities. A copy of the audit committee charter is posted on our website, www.royl.com The board has determined that Ronald Verdier qualifies as an "audit committee financial expert" as defined in Item 407 (d)(5) of the Securities and Exchange Commission.

At the end of 2015, the members of the audit committee were Ronald Verdier, chair, Ronald Buck and Gary Grinsfelder.

Code of Business Conduct and Ethics

We have adopted a code of business conduct and ethics for our directors and executive officers. The code is posted on our website, www.royl.com.

Compliance with Section 16(a) of the Exchange Act

Section 16(a) of the Securities Exchange Act of 1934 and Securities and Exchange Commission regulations require that Royale Energy's directors, certain officers, and greater than 10 percent shareholders file reports of ownership and changes in ownership with the SEC and the NASD and furnish Royale Energy with copies of all such reports they file. Based solely upon a review of the copies of the forms furnished to Royale Energy, or representations from certain reporting persons that no reports were required, Royale Energy believes that no persons failed to file required reports on a timely basis for 2015, except that the initial ownership report of Mr. Buck on Form 3 was filed late, in January 2016, after his election to the board in June 2015.

Item 11 **Executive Compensation**

The following table summarizes the compensation of the chief executive officer, chief financial officer and the two other most highly non-executive employees (the "named executives and employees") of Royale Energy and its subsidiaries during the past year. No stock options, stock awards or other plan based compensation awards were made during 2015.

Name and Principal Position	Year	Salary (4)	Bonus	Option Awards (1)	All Other Compensation (2)	Total
Jonathan Gregory, CEO (4) (5)	2015	$ 70,823	$ -		$ -	$ 70,823
Donald H. Hosmer	2015	$ 177,084	$ -		$ 18,063	$ 195,147
President	2014	$ 230,192	$ 25,000		$ 6,906	$ 262,098
	2013	$ 230,192	$ 25,000		$ 7,656	$ 262,848
Stephen M. Hosmer (4)	2015	$ 230,192	$ -		$ 17,968	$ 248,160
President, & CFO	2014	$ 230,192	$ 25,000		$ 18,906	$ 274,098
	2013	$ 230,192	$ 25,000		$ 19,656	$ 274,848
Mohamed Abdel-Rahmen (3)	2015	$ 155,268	$ -		$ 4,246	$ 159,514
VP Exploration	2014	$ 163,692	$ -		$ 4,911	$ 168,603
	2013	$ 167,025	$ -		$ 5,011	$ 172,036
Charles Tiano (3)	2015	$ 49,500	$ 196,500		$ 7,380	$ 253,380
Director of Investor	2014	$ 50,642	$ 178,892		$ 6,886	$ 236,420
Relations	2013	$ 49,955	$ 193,825		$ 7,313	$ 251,093

(1) In October 2014, Donald Hosmer and Stephen Hosmer (together with the other members of the board of directors) were each granted 20,000 options to purchase common stock at an exercise or base price of $5.00 per shares, which vested during 2015. These options were granted for a period of 3 years and will expire on December 31, 2017. At December 31, 2015, Royale Energy's stock price, $0.358, was less than the weighted average exercise price, and as such the outstanding and exercisable stock options had no intrinsic value.

(2) All other compensation consists of matching contributions to the Company's simple IRA plan, except for Donald H. Hosmer and Stephen M. Hosmer, who also received a $12,000 car allowance.

(3) Mr. Abdel-Rahmen and Mr. Tiano are highly compensated employees under SEC rules who did not serve as executive officers during 2015. Mr Abdel-Rahmen retired from the Company in October 2015.

(4) During 2015, Jonathan Gregory and Stephen Hosmer received a portion of their compensation in shares of common stock, valued at the closing market price on the date of grant, instead of cash. Of the $70,823 paid to Jonathan Gregory, $21,581 was paid in cash and 108,644 shares of common stock were issued, valued at $49,242. Of the $230,192 paid to Stephen Hosmer, $173,945 was paid in cash and 200,564 share of common stock were issued, valued at $56,247.

(5) Mr. Gregory was appointed CEO (principal executive officer) in 2015.

Stock Options and Equity Compensation; Outstanding Equity Awards at Fiscal Year End

The following table presents the number of unexercised options at the 2015 year end for each named executive officer. No unvested stock awards were outstanding at the end of 2015.

	Options			
Name	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Option exercise price ($)	Option expiration date
Jonathan Gregory	20,000(1)	-	$ 5.00	12/31/2017
Donald H. Hosmer	20,000(1)	-	$ 5.00	12/31/2017
Stephen M. Hosmer	20,000(1)	-	$ 5.00	12/31/2017

(1) At the October 10, 2014 Board of Directors meeting, directors of Royale Energy were granted 20,000 options each to purchase common stock at an exercise price of $5.00 per share. These options have become exercisable and will expire on December 31, 2017.

Compensation Committee Report

Our executive compensation committee has reviewed and discussed the following Compensation Discussion and Analysis with management and, based on its discussion and review, has recommended that the Compensation Discussion and Analysis be included in this proxy statement.

Members of the Compensation Committee:

Ronald Buck and Gary Grinsfelder

All members of the compensation committee are independent members of the board of directors.

Compensation Discussion and Analysis

Our executive compensation policy is designed to motivate, reward and retain the key executive talent necessary to achieve our business objectives and contribute to our long-term success. Our compensation policy for our executive officers focuses primarily on determining appropriate salary levels and performance-based cash bonuses.

The elements of executive compensation at Royale Energy consist mainly of cash salary and, if appropriate, a cash bonus at year end. The compensation committee makes recommendations to the board of directors annually on the compensation of the three top executives: Jonathan Gregory, Chief Executive Officer, Donald H. Hosmer, President of Business Development and Stephen M. Hosmer, President and Chief Financial Officer. We do not have employment contracts with either of our executive officers.

Royale Energy also does not provide extensive personal benefits to its executives beyond those benefits, such as health insurance, that are provided to all employees. Donald Hosmer and Stephen Hosmer each receive an annual car allowance.

Policy

The compensation committee's primary responsibility is making recommendations to the board of directors relating to compensation of our officers. The committee also makes recommendations to the board of directors regarding employee benefits, our defined benefit plans, defined contribution plans, and stock based plans.

Determination

To determine executive compensation, the committee, in December each year, meets with our officers to review our compensation programs, discuss the performance of the company, the duties and responsibilities of each of the officers pay levels and business results compared to others similarly situated within the industry. The committee then makes recommendations to the board of directors for any adjustment to the officers' compensation levels. The committee does not employ compensation consultants to make recommendations on executive compensation.

Compensation Elements

Base. Base salaries for our executive officers are established based on the scope of their responsibilities, taking into account competitive market compensation paid by our peers. Base salaries are reviewed annually. The salaries we paid to our most highly paid executive officers for the last three years are set forth in the Summary Compensation Table included under *Executive Compensation*.

Bonus. The compensation committee meets annually to determine the quantity, if any, of the cash bonuses of executive officers. The amount granted is based, subjectively, upon the company's stock price performance, earnings, revenue, reserves and production. The committee does not use quantifiable metrics for these criteria; but rather uses each in balance to assess the strength of the company's performance. The committee believes that formulaic approaches to cash incentives can foster an unhealthy balance between short-term and long-term goals. In 2014, the compensation committee did award bonuses to the company's executive officers, Stephen and Don Hosmer, in the amount of $25,000 to each officer. No bonuses were paid to executive officers in 2015.

Compensation of Directors

In 2015, board members or committee member received fees for attendance at board meetings or committee meetings during the year. In addition to cash payments, common stock was issued in lieu of compensation or reimbursements. Royale Energy also reimbursed directors for the expenses incurred for their services.

In addition, Royale Energy's Chairman of the Board and former President, Harry E. Hosmer, renders and receives compensation for management consulting services to Royale Energy on an ongoing basis. *See Certain Relationships and Related Transactions, page 23.*

The following table describes the compensation paid to our directors who are not also named executives for their services in 2015.

Name	Fees earned or paid in cash or Common Stock ($)	Stock awards ($)	Option awards ($)	All Other Compensation (1) ($)	Total ($)
Harry E. Hosmer (2)	$ 184,410	$ 0	$ 0	$ 6,619	$ 191,029
Gary Grinsfelder	$ 25,000	$ 0	$ 0	0	$ 25,000
Ronald Buck	$ 12,500	$ 0	$ 0	0	$ 12,500
Ronald Verdier	$ 6,250	$ 0	$ 0	0	$ 6,250

(1) Other compensation paid to Harry E. Hosmer in 2015 consisted of payments for medical and dental insurance coverage.
(2) Harry E. Hosmer's compensation in 2015 includes compensation of $13,854, which was paid by the issuance of 49,768 shares of Royale's common stock. The stock was valued at the closing market prices on the dates immediately preceding their issuance.

Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Common Stock

On February 23, 2016, 17,303,831 shares of Royale Energy's common stock were outstanding.

The following table contains information regarding the ownership of Royale Energy's common stock as of February 23, 2016, by:

i) each person who is known by Royale Energy to own beneficially more than 5% of the outstanding shares of each class of equity securities;

ii) each director of Royale Energy, and

iii) all directors and officers of Royale Energy as a group. Except pursuant to applicable community property laws and except as otherwise indicated, each shareholder identified in the table possesses sole voting and investment power with respect to its or his shares. The holdings reported are based on reports filed with the Securities and Exchange Commission and the Company by the officers, directors and 5% shareholders pursuant to Section 16 of the Securities Exchange Act of 1934.

Stockholder (1)	Number (2)	Percent
Harry E. Hosmer, (2) (3)	764,678	4.41%
Donald H. Hosmer, (2) (3)	1,400,226	8.08%
Stephen M. Hosmer, (2) (3) (4)	1,386,599	7.89%
Ronald L. Buck	42,668	*
Jonathan Gregory, (2)	288,877	1.67%
Gary Grinsfelder, (2)	25,440	*
Ronald Verdier	2,000	*
All officers and directors as a group	3,890,488	22.35%
* Less than 1%		

(1) The mailing address of each listed stockholder is 3777 Willow Glen Drive, El Cajon, California 92019.

(2) Includes options to purchase the following number of shares of common stock which were vested and exercisable on March 6, 2016: Harry E. Hosmer 20,000, Donald H. Hosmer 20,000; Stephen M. Hosmer 20,000; Gary Grinsfelder 20,000; Jonathan Gregory 20,000.

(3) Donald H. Hosmer and Stephen M. Hosmer are sons of Harry E. Hosmer, chairman of the board.

(4) Includes 24,000 shares owned by Stephen M. Hosmer's minor children.

Preferred Stock

Holders Series AA convertible preferred stock have voting rights equal to the number of shares into which they are convertible. On December 31, 2015, 46,662 shares of Series AA convertible preferred stock were outstanding. The shares of each series of preferred shares are convertible into shares of Royale Energy's common stock at the option of the security holder, at the rate of two shares of convertible preferred stock for each share of common stock. The preferred stock is not registered under the Securities Exchange Act of 1934, and no market exists for the preferred stock. The total number of shares of common stock issuable on conversion of all outstanding shares of preferred stock equals less than 1% of the outstanding common stock of Royale Energy. To Royale Energy's knowledge, none of the preferred shareholders would own more than 1% of Royale Energy's common stock, if their preferred shares were converted to common shares.

Item 13 Certain Relationships and Related Transactions

In 1989, the board of directors adopted a policy (the "1989 policy") that permits each director and officer of Royale Energy to purchase from Royale Energy, at its cost, up to one percent (1%) fractional interest in any well to be drilled by Royale Energy. When an officer or director elects to make such a purchase, the amount charged per each percentage working interest is equal to Royale Energy's actual pro rata cost of drilling and completion, rather than the higher amount that Royale Energy charges to working interest holders for the purchase of a percentage working interest in a well. Of the current officers and directors, Donald Hosmer, Stephen Hosmer and Harry E. Hosmer at various times have elected under the 1989 policy to purchase interests in certain wells Royale Energy has drilled.

Under the 1989 policy, officers and directors may elect to participate in wells at any time up until drilling of the prospect begins. Participants are required to pay all direct costs and expenses through completion of a well, whether or not the well drilling and completion expenses exceed Royale Energy's cost estimates, instead of paying a set, turnkey price (as do outside investors who purchase undivided working interests from Royale Energy). Thus, they participate on terms similar to other oil and gas industry participants or joint venturers. Participants are invoiced in advance for their share of estimated direct costs of drilling and completion and later actual costs are reconciled, as Royale Energy incurs expenses and participants make further payments as necessary.

Officer and director participants under this program do not pay some expenses paid by outside, retail investors in working interests, such as sales commissions, if any, or marketing expenses. The outside, turnkey drilling agreement investors, on the other hand, are not obligated to pay additional costs if a drilling project experiences cost overruns or unanticipated expenses in the drilling and completion stage. Accordingly, Royale Energy's management believes that its officers and directors who participate in wells under the board of directors' policy do so on terms the same as could be obtained by unaffiliated oil and gas industry participants in arms-length transactions, albeit those terms are different than the turnkey agreement under which outside investors purchase fractional undivided working interests from Royale Energy.

Donald and Stephen Hosmer each have participated individually in 178 wells each under the 1989 policy. The Hosmer Trust, a trust for the benefit of family members of Harry E. Hosmer, has participated in 177 wells.

Investments in wells under the 1989 policy for the three years ended December 31, 2015, 2014, and 2013 are as follows:

	Year	# of fractional interests	Amount
Donald Hosmer	2015	2	$ 3,143
	2014	4	$ 18,692
	2013	6	$ 31,767
Stephen Hosmer	2015	4	$ 4,389
	2014	4	$ 7,714
	2013	5	$ 12,262
Hosmer Trust	2015	4	$ 5,633
	2014	3	$ 9,985
	2013	6	$ 41,488

Current and former officers and directors were billed $0, $0 and $16,967 for their interests for the three years ended December 31, 2015, 2014, and 2013, respectively.

Royale Energy's chairman of the board and former president, Harry E. Hosmer, renders management consulting services to Royale Energy on an ongoing basis. Royale Energy compensated Mr. Hosmer $165,660, $165,660 and $193,270 for his consulting services in 2015, 2014, and 2013, respectively, and pays his medical insurance costs. Mr. Hosmer's consulting services are in conjunction with his service on the board of directors, for which he receives reimbursement of expenses to attend meetings.

Item 14 Principal Accountant Fees and Services

SingerLewak LLP served as the independent auditors to audit the Company's financial statements for the fiscal year ended December 31, 2015 and 2014. This is the second annual audit performed by SingerLewak LLP, Padgett Stratemann & Co., LLP previously performed annual audits. The aggregate fees billed by SingerLewak LLP and Padgett Stratemann & Co., LLP for the years ended December 31, 2015 and 2014 are as follows, respectively:

	2015	2014
Audit fees (1)	$ 121,258	$ 159,891
Tax fees (2)	$ -	$ -
All other fees (3)	$ 54,638	$ 25,600
Total	$ 175,896	$ 185,491

(1) Audit fees are fees for professional services rendered for the audit of Royale Energy's annual financial statements, reviews of financial statements included in the company's Forms 10-Q, and reviews of documents filed with the U.S. Securities and Exchange Commission.

(2) Tax fees consist of tax planning, consulting and tax return reviews.

(3) Other fees consist of work on registration statements under the Securities Act of 1933.

The audit committee of Royale Energy has adopted policies for the pre-approval of all audit and non-audit services provided by the company's independent auditor. The policy requires pre-approval by the audit committee of specifically defined audit and non-audit services. Unless the specific service has been previously pre-approved with respect to that year, the audit committee must approve the permitted service before the independent auditor is engaged to perform it.

No representatives of SingerLewak LLP are expected to be present at the annual meeting. Although the audit committee has the sole responsibility to appoint the auditors as required under the Securities Exchange Act of 1934, the committee welcomes any comments from shareholders on auditor selection or performance. Comments may be sent to the audit committee chair, Ronald Verdier, care of Royale Energy's executive office, 3777 Willow Glen Drive, El Cajon, California 92019.

PART IV

Item 15 Exhibits and Financial Statement Schedules

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about Royale Energy or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

1. Financial Statements. See Index to Financial Statements, page F-1

2. Schedules. Supplemental Information About Oil and Gas Producing Activities (Unaudited) begins on page F-20.

3. Exhibits. Certain of the exhibits listed in the following index are incorporated by reference.

1.1	Placement Agent Agreement between the Company and C.K. Cooper & Company, Inc., dated October 25, 2013, incorporated by reference to Exhibit 10.2 of the Company's Form 8-K filed October 29, 2013.
3.1	Restated Articles of Incorporation of Royale Energy, Inc., incorporated by reference to Exhibit 3.1 of Royale Energy's Form 10-Q filed August 14, 2009.
3.2	Amended and Restated Bylaws of Royale Energy, Inc., incorporated by reference to Exhibit 3.2 of Royale Energy's Form 10-K filed March 27, 2009.
4.1	Series E Warrant issued to certain affiliates of Cranshire Capital, L.P., incorporated by reference to Exhibit 4.2 of the Company's Form 8-K filed October 29, 2013.
4.2	Certificate of Determination of the Series AA Convertible Preferred Stock, incorporated by reference to Exhibit 4.2 of Royale Energy's Form 10-SB Registration Statement.
10.1	Form of Indemnification Agreement, incorporated by reference to Exhibit 10.3 of Royale Energy's Form 10-SB Registration Statement.
10.2	Sales Agreement between the Company and C.K. Cooper & Company, Inc., dated February 17, 2013, incorporated by reference to Exhibit 10.1 of the Company's Form 8-K filed February 17, 2013.
10.3	Securities Purchase Agreement between the Company and certain buyers dated as of October 28, 2013, incorporated by reference to Exhibit 4.3 of the Company's Form 8-K filed October 29, 2013.
10.4	Convertible Note issued to certain affiliates of Cranshire Capital, L.P., incorporated by reference to Exhibit 4.1 of the Company's Form 8-K filed October 29, 2013.
10.5	Secured Loan Agreement between Royale Energy and AmericanWest Bank, NA, dated December 24, 2013, filed herewith.
23.1	Consent of SingerLewak L.L.P., filed herewith.
23.2	Consent of Padgett Stratemann & Co, L.L.P., filed herewith.
23.3	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
23.4	Consent of Source Energy, LLC, filed herewith.
31.1	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
31.2	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
31.3	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
32.1	Section 1350 Certification, filed herewith.
32.2	Section 1350 Certification, filed herewith.
32.3	Section 1350 Certification, filed herewith.
99.1	Report of Netherland Sewell & Associates, Inc., filed herewith.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

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

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SIGNATURES

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

	Royale Energy, Inc.
Date: March 14, 2016	*/s/ Jonathan Gregory* Jonathan Gregory Chief Executive Officer

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

Date: March 14, 2016	*/s/ Harry E. Hosmer* Harry E. Hosmer Chairman of the Board of Directors
Date: March 14, 2016	*/s/ Donald H. Hosmer* Donald H. Hosmer Director, and President of Business Development
Date: March 14, 2016	*/s/ Stephen M. Hosmer* Stephen M. Hosmer Director, President, Chief Financial Officer and Secretary
Date: March 14, 2016	*/s/ Ronald Buck* Ronald Buck Director
Date: March 14, 2016	*/s/ Ronald Verdier* Ronald Verdier Director
Date: March 14, 2016	*/s/ Gary Grinsfelder* Gary Grinsfelder Director
Date: March 14, 2016	*/s/ Jonathan Gregory* Jonathan Gregory Director, Chief Executive Officer

ROYALE ENERGY, INC.
INDEX TO FINANCIAL STATEMENTS
AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Royale Energy, Inc.

We have audited the accompanying balance sheets of Royale Energy, Inc. (the “Company”) as of December 31, 2015 and 2014, and the related statements of comprehensive loss, stockholders’ deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Royale Energy, Inc. as of December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

SingerLewak LLP

Los Angeles, California
March 14, 2016

ROYALE ENERGY, INC.
BALANCE SHEETS
DECEMBER 31, 2015 AND 2014

	2015	2014
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 3,763,819	$ 3,061,841
Other Receivables, net	381,192	1,760,181
Revenue Receivables	147,936	493,295
Prepaid Expenses	114,036	158,404
Total Current Assets	4,406,983	5,473,721
Other Assets	730,844	510,821
Oil And Gas Properties (Successful Efforts Basis), Real Property and Equipment and Fixtures, net	6,532,478	7,594,666
Total Assets	$ 11,670,305	$ 13,579,208

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

ROYALE ENERGY, INC.
BALANCE SHEETS
DECEMBER 31, 2015 AND 2014

	2015	2014
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current Liabilities:		
Accounts Payable and Accrued Expenses	$ 2,937,226	$ 4,502,559
Current Portion of Long-Term Debt	30,528	29,031
Deferred Drilling Obligations	8,415,528	7,937,786
Total Current Liabilities	11,383,282	12,469,376
Noncurrent Liabilities:		
Asset Retirement Obligation	1,096,179	804,206
Note Payable, less current portion	1,416,325	1,446,853
Total Noncurrent Liabilities	2,512,504	2,251,059
Total Liabilities	13,895,786	14,720,435
Stockholders' Deficit:		
Convertible Preferred Stock, Series AA, No Par Value, 147,500 Shares Authorized; 46,662 Shares Issued and Outstanding, at December 31, 2015 and 2014, Respectively	136,149	136,149
Common Stock, No Par Value, 30,000,000 Shares Authorized; 16,396,579 and 14,945,789 Shares Issued and Outstanding, at December 31, 2015 and 2014, respectively	38,846,751	38,014,730
Paid in Capital	425,678	337,640
Accumulated Deficit	(41,634,059)	(39,623,243)
Accumulated Other Comprehensive Loss	-	(6,503)
Total Stockholders' Deficit	(2,225,481)	(1,141,227)
Total Liabilities and Stockholders' Deficit	$ 11,670,305	$ 13,579,208

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

ROYALE ENERGY, INC.
STATEMENTS OF COMPREHENSIVE LOSS
FOR THE YEARS ENDED DECEMBER 31, 2015, AND 2014

	2015	2014
Revenues:		
Sale of Oil and Gas	$ 1,018,928	$ 2,598,297
Supervisory Fees and Other	694,160	623,201
Total Revenues	1,713,088	3,221,498
Costs and Expenses:		
General and Administrative	3,181,571	3,162,113
Lease Operating	1,000,769	1,427,673
Delay Rentals	448,313	616,806
Lease Impairment	424,163	268,093
Well Equipment Write Down	60,960	-
Bad Debt Expense	536,538	653,133
Legal and Accounting	558,471	401,160
Marketing	326,143	430,779
Depreciation, Depletion and Amortization	400,813	315,574
Total Costs and Expenses	6,937,741	7,275,331
Gain on Turnkey Drilling Programs	2,330,969	1,640,731
Gain on Sale of Assets	968,956	342,851
Loss from Operations	(1,924,728)	(2,070,251)
Other Expense:		
Interest Expense	(86,088)	(81,605)
Loss Before Income Tax Expense	(2,010,816)	(2,151,856)
Provision for Income Taxes	-	-
Net Loss	(2,010,816)	(2,151,856)
Basic Loss Per Share	(0.13)	(0.14)
Diluted Loss Per Share	(0.13)	(0.14)
Other Comprehensive Income (Loss)		
Unrealized Loss on Equity Securities	-	16,448
Less: Reclassification Adjustment for Losses Included in Net Income	(6,503)	-
Other Comprehensive Gain (Loss) before tax	6,503	(16,448)
Other Comprehensive Gain (Loss), net of tax	6,503	(16,448)
Comprehensive Loss	(2,004,313)	(2,168,304)

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

ROYALE ENERGY, INC.
STATEMENTS OF STOCKHOLDERS' DEFICIT
FOR THE YEARS ENDED DECEMBER 31, 2015 and 2014

	Common Stock		Preferred Stock Series AA				Accumulated	
	Number of Shares Issued and Outstanding	Amount	Number of Shares Issued and Outstanding	Amount	Additional Paid in Capital	Accumulated Deficit	Other Comprehensive Income (Loss)	Total
Balance, December 31, 2013	14,942,728	$ 37,996,865	52,784	$ 154,014	$ 303,855	$ (37,471,387)	$ 9,945	$ 993,292
Series AA Conversion to Common (2 for 1)	3,061	$ 17,865	(6,122)	(17,865)				-
Director’s Stock Option Grant					33,785			33,785
Available for Sale Securities - Unrealized Gain (Loss), net of tax							(16,448)	(16,448)
Net Loss						(2,151,856)		(2,151,856)
Balance, December 31, 2014	14,945,789	$ 38,014,730	46,662	$ 136,149	$ 337,640	$ (39,623,243)	$ (6,503)	$ (1,141,227)
Common Stock Private Placement Sale	701,397	534,274			(44,158)			490,116
Director's Stock Options Grant					86,877			86,877
Common Stock RDO Private Placement Sale	485,486	153,876			45,319			199,195
Common Stock Issued to Executives in lieu of Compensation	263,907	143,871						143,871
Available for Sale Securities - Reclassification Adjustment for Losses Included in Net Income							6,503	6,503
Net Loss						(2,010,816)		(2,010,816)
Balance, December 31, 2015	16,396,579	$ 38,846,751	46,662	$ 136,149	$ 425,678	$ (41,634,059)	$ -	$ (2,225,481)

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

ROYALE ENERGY, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2015 and 2014

	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (Loss)	$ (2,010,816)	$ (2,151,856)
Adjustments to Reconcile Net Loss to Net Cash Used by Operating Activities:		
Depreciation, Depletion, and Amortization	400,813	315,574
Lease Impairment	424,163	268,093
Gain on Sale of Assets	(968,956)	(342,851)
Gain on Turnkey Drilling Programs	(2,330,969)	(1,640,731)
Bad Debt Expense	536,538	653,133
Stock-Based Compensation	230,749	33,785
Realized Loss on Equity Securities	6,503	-
Well Equipment and Other Assets Write Down	60,960	-
(Increase) Decrease in:		
Other & Revenue Receivables	1,187,810	(1,225,817)
Prepaid Expenses and Other Assets	(236,615)	16,569
Increase (Decrease) in:		
Accounts Payable and Accrued Expenses	(1,273,360)	(887,926)
Deferred Drilling Obligations	477,742	1,811,853
Deferred Income Taxes	-	(1,775)
Net Cash Used by Operating Activities	(3,495,438)	(3,151,949)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for Oil And Gas Properties	(3,753,134)	(3,182,600)
Proceeds from Turnkey Drilling Programs	4,955,734	4,172,296
Proceeds from Sale of Assets	2,334,537	369,977
Net Cash Provided by Investing Activities	3,537,137	1,359,673
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from Long-Term Debt	-	-
Principal Payments on Long-Term Debt	(29,031)	(24,116)
Proceeds from Stock Options and Warrant Exercises	-	-
Proceeds from Sale of Common Stock	689,310	-
Net Cash Provided by (Used In) Financing Activities	660,279	(24,116)
Net Increase (Decrease) in Cash and Cash Equivalents	701,978	(1,816,392)
Cash & Cash Equivalents at Beginning of Year	3,061,841	4,878,233
Cash & Cash Equivalents at End of Year	$ 3,763,819	$ 3,061,841
Cash Paid for Interest	$ 86,088	81,606
Cash Paid for Taxes	$ 1,000	3,855
Supplemental Schedule of Non-Cash Investing and Financing Transactions:		
Conversion of Series AA Stock to Common Stock	$ -	$ 17,865
Unrealized Gain (Loss) on Available-for-Sale Securities, net of tax effect	$ -	$ (16,448)
Reclassification Adjustment for Losses Included in Net Income	$ (6,503)	$ -

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

ROYALE ENERGY, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This summary of significant accounting policies of Royale Energy, Inc. ("Royale Energy," "Royale," or the "Company") is presented to assist in understanding Royale Energy's financial statements. The financial statements and notes are representations of Royale Energy's management, which is responsible for their integrity and objectivity. These accounting policies conform to accounting principles generally accepted in the United States of America and have been consistently applied in the preparation of the financial statements.

Description of Business

Royale Energy is an independent oil and gas producer which also has operations in the area of turnkey drilling. Royale Energy owns wells and leases in major geological basins located primarily in California, Texas, Alaska and Utah. Royale Energy offers fractional working interests and seeks to minimize the risks of oil and gas drilling by selling multiple well drilling projects which do not include the use of debt financing.

Use of Estimates

The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America and requires management to 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 revenues and expenses during the reporting period. Actual results could differ from those estimates. As reflected in the accompanying financial statements, the Company has negative working capital, losses from operations and negative cash flows from operations.

Material estimates that are particularly susceptible to significant change relate to the estimate of Company oil and gas reserves prepared by an independent engineering consultant. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proven reserves. Estimated reserves are used in the calculation of depletion, depreciation and amortization, unevaluated property costs, impairment of oil and natural gas properties, estimated future net cash flows, taxes, and contingencies.

Liquidity

The primary sources of liquidity have historically been issuances of common stock and operations. Until we become cash flow positive, we anticipate that our primary sources of liquidity will be from the issuance of debt and/or equity, and the sale of oil and natural gas property participation interest. Assuming there are no further changes in expected sales and expense trends subsequent to March 14, 2016, the Company believes that its cash position together with anticipated financing activities, which include the sale of our office building and land, will be sufficient to continue operations for the foreseeable next twelve months.

Revenue Recognition

Royale's primary business is oil and gas production. Natural gas flows from the wells into gathering line systems, which are equipped occasionally with compressor systems, which in turn flow into metered transportation and customer pipelines. Monthly, price data and daily production are used to invoice customers for amounts due to Royale Energy and other working interest owners. Royale Energy operates virtually all of its own wells and receives industry standard operator fees.

Royale Energy generally sells crude oil and natural gas under short-term agreements at prevailing market prices. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured.

Revenues from the production of oil and natural gas properties in which the Royale Energy has an interest with other producers are recognized on the basis of Royale Energy's net working interest. Differences between actual production and net working interest volumes are not significant.

Royale Energy's financial statements include its *pro rata* ownership of wells. Royale Energy usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Royale Energy generally retains about a 50% working interest. All results, successful or not, are included at its pro rata ownership amounts: revenue, expenses, assets, and liabilities as defined in FASB ASC 932-323-25 and 932-360.

Oil and Gas Property and Equipment

Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Interest costs, to the extent they are incurred to finance expenditures during the construction phase, are included in property, plant and equipment and are depreciated over the service life of the related assets.

Royale Energy uses the “successful efforts” method to account for its exploration and production activities. Under this method, Royale Energy accumulates its proportionate share of costs on a well-by-well basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred, and capitalizes expenditures for productive wells. Royale Energy amortizes the costs of productive wells under the unit-of-production method.

Royale Energy carries, as an asset, exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where Royale Energy is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain Royale Energy’s wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Proved oil and gas properties held and used by Royale Energy are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

Royale Energy estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated evaluation assumptions for crude oil commodity prices. Annual volumes are based on field production profiles, which are also updated annually. Prices for natural gas and other products are based on assumptions developed annually for evaluation purposes.

Impairment analyses are generally based on proved reserves. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value. During 2015 and 2014, impairment losses of $424,163 and $268,093, respectively, were recorded on various capitalized lease and land costs that were no longer viable.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that Royale Energy expects to hold the properties. The valuation allowances are reviewed at least annually.

Upon the sale or retirement of a complete field of a proved property, Royale Energy eliminates the cost from its books, and the resultant gain or loss is recorded to Royale Energy’s Statement of Operations. Upon the sale of an entire interest in an unproved property where the property has been assessed for impairment individually, a gain or loss is recognized in Royale Energy’s Statement of Operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a recovery of the cost in the interest retained with any excess funds recognized as a gain. Should Royale Energy’s turnkey drilling agreements include unproved property, total drilling costs incurred to satisfy its obligations are recovered by the total funds received under the agreements. Any excess funds are recorded as a Gain on Turnkey Drilling Programs, and any costs not recovered are capitalized and accounted for under the “successful efforts” method.

Royale Energy sponsors turnkey drilling agreement arrangements in unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as Deferred Drilling Obligations, and then reduced as costs to complete its obligations are incurred with any excess booked against its property account to reduce any basis in its own interest. Gains on Turnkey Drilling Programs represent funds received from turnkey drilling participants in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account; and are recognized only upon making this determination after Royale's obligations have been fulfilled.

The contracts require the participants pay Royale Energy the full contract price upon execution of the agreement. Royale Energy completes the drilling activities typically between 10 and 30 days after drilling begins. The participant retains an undivided or proportional beneficial interest in the property, and is also responsible for its proportionate share of operating costs. Royale Energy retains legal title to the lease. The participants purchase a working interest directly in the well bore.

In these working interest arrangements, the participants are responsible for sharing in the risk of development, but also sharing in a proportional interest in rights to revenues and proportional liability for the cost of operations after drilling is completed and the interest is conveyed to the participant.

A certain portion of the turnkey drilling participant's funds received are non-refundable. The company holds all funds invested as Deferred Drilling Obligations until drilling is complete. Occasionally, drilling is delayed due to the permitting process or drilling rig availability. At December 31, 2015 and 2014, Royale Energy had Deferred Drilling Obligations of $8,415,528 and $7,937,786, respectively.

If Royale Energy is unable to drill the wells, and a suitable replacement well is not found, Royale would retain the non-refundable portion of the contact and return the remaining funds to the participant. Included in cash and cash equivalents are amounts for use in completion of turnkey drilling programs in progress.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit, and highly liquid debt instruments with maturities of three months or less.

Other Receivables

Our other receivables consists of receivables from direct working interest investors and industry partners. We provide for uncollectible accounts receivable using the allowance method of accounting for bad debts. Under this method of accounting, a provision for uncollectible accounts is charged directly to bad debt expense when it becomes probable the receivable will not be collected. The allowance account is increased or decreased based on past collection history and management's evaluation of accounts receivable. All amounts considered uncollectible are charged against the allowance account and recoveries of previously charged off accounts are added to the allowance. At December 31, 2015 and 2014, the Company established an allowance for uncollectable accounts of $2,270,773 and $1,734,713, respectively, for receivables from direct working interest investors whose expenses on non-producing wells were unlikely to be collected from revenue.

Revenue Receivables

Our revenue receivables consists of receivables related to the sale of our natural gas and oil. Once a production month is completed we receive payment approximately 15 to 30 days later.

Equipment and Fixtures

Equipment and fixtures are stated at cost and depreciated over the estimated useful lives of the assets, which range from three to seven years, using the straight-line method. Repairs and maintenance are charged to expense as incurred. When assets are sold or retired, the cost and related accumulated depreciation are removed from the accounts and any resulting gain or loss is included in income. Maintenance and repairs, which neither materially add to the value of the property nor appreciably prolong its life, are charged to expense as incurred. Gains or losses on dispositions of property and equipment, other than oil and gas, are reflected in operations.

Income (Loss) Per Share

Basic and diluted losses per share are calculated as follows:

	For the Year Ended December 31, 2015		
	Loss (Numerator)	Shares (Denominator)	Per-Share Amount
Basic Loss Per Share:			
Net loss available to common stock	$ (2,010,816)	15,194,534	$ (0.13)
Loss Per Share:			
Effect of dilutive securities and stock options		-	$ -
Net loss available to common stock	$ (2,010,816)	15,194,534	$ (0.13)

	For the Year Ended December 31, 2014		
	Loss (Numerator)	Shares (Denominator)	Per-Share Amount
Basic Loss Per Share:			
Net income available to common stock	$ (2,151,856)	14,943,323	$ (0.14)
Loss Per Share:			
Effect of dilutive securities and stock options		-	$ -
Net loss available to common stock	$ (2,151,856)	14,943,323	$ (0.14)

For the years ended December 31, 2015 and 2014, Royale Energy had dilutive securities of 23,331 and 161,966, respectively. These securities were not included in the dilutive loss per share due to their antidilutive nature.

Stock Based Compensation

Royale Energy has a stock-based employee compensation plan, which is more fully described in Note 11. Effective January 1, 2006, the Company adopted the Compensation – Stock Compensation Topic of the FASB Accounting Standards Codification, which addresses the accounting for stock-based payment transactions in which an enterprise receives employee services in exchange for (a) equity instruments of the enterprise or (b) liabilities that are based on the fair value of the enterprise's equity instruments or that may be settled by the issuance of such equity instruments. The Company uses the Black-Scholes option-pricing model to determine the fair value of stock-based awards.

Income Taxes

Royale utilizes the asset and liability approach to measure deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates in accordance with the Income Taxes Topic of the FASB Accounting Standards Codification. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. Under the Topic, deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The provision for income taxes is based on pretax financial accounting income. Deferred tax assets and liabilities are recognized for the expected tax consequences of temporary differences between the tax basis of assets and liabilities and their reported net amounts.

Fair Value Measurements

According to Fair Value Measurements and Disclosures Topic of the FASB Accounting Standards Codification, assets and liabilities that are measured at fair value on a recurring and nonrecurring basis in period subsequent to initial recognition, the reporting entity shall disclose information that enable users of its financial statements to assess the inputs used to develop those measurements and for recurring fair value measurements using significant unobservable inputs, the effect of the measurements on earnings for the period.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In determining fair value, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible as well as considers counterparty credit risk in its assessment of fair value. Carrying amounts of the Company's financial instruments, including cash equivalents, accounts receivable, accounts payable and accrued liabilities, approximate their fair values as of the balance sheet dates because of their generally short maturities.

The fair value hierarchy distinguishes between (1) market participant assumptions developed based on market data obtained from independent sources (observable inputs) and (2) an entity's own assumptions about market participant assumptions developed based on the best information available in the circumstances (unobservable inputs). The fair value hierarchy consists of three broad levels, which gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are described below:

Level 1: Quoted prices (unadjusted) in active markets that are accessible at the measurement date for assets or liabilities.

Level 2: Directly or indirectly observable inputs as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3: Unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions

At December 31, 2015 and 2014, Royale Energy does not have any financial assets measured and recognized at fair value on a recurring basis. The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "*Asset Retirement and Environmental Obligations"* ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company's asset retirement obligations.

Reclassifications

Certain items in the financial statements have been reclassified to maintain consistency and comparability for all periods presented herein.

Recently Issued Accounting Pronouncements

The Company has reviewed the updates issued by the Financial Accounting Standards Board (FASB) during the year ended December 31, 2015.

ASU 2014-15: Presentation of Financial Statements – Going Concern (Subtopic 205-40)

In June 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements – Going Concern. Before the issuance of ASU 2014-15, there was no guidance in U.S. GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern or to provide related footnote disclosures. ASU 2014-15 requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards as specified in the guidance. ASU 2014-15 becomes effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. The Company is currently evaluating the effects of adopting ASU 2014-15 on its consolidated financial statements but the adoption is not expected to have a significant impact on the Company's consolidated financial statements.

ASU 2015-14: Revenue from Contracts with Customers (Topic 606)

In August 2015, the FASB issued ASU No. 2015-14, Revenue From Contracts With Customers (Topic 606)." The amendments in this ASU defer the effective date of ASU 2014-09. Public business entities should apply the guidance in ASU 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Company is still evaluating the effect of the adoption of ASU 2014-09.

ASU 2016-01: Financial Instruments – Overall – Recognition and Measurement of Financial Assets and Financial Liabilities (Subtopic 825-10)

In January 2016, FASB issued ASU 2016-0,1 which requires an entity to: (i) measure equity investments at fair value through net income, with certain exceptions; (ii) present in Other Comprehensive Income the changes in instrument-specific credit risk for financial liabilities measured using the fair value option; (iii) present financial assets and financial liabilities by measurement category and form of financial asset; (iv) calculate the fair value of financial instruments for disclosure purposes based on an exit price and; (v) assess a valuation allowance on deferred tax assets related to unrealized losses of AFS debt securities in combination with other deferred tax assets. The Update provides an election to subsequently measure certain nonmarketable equity investments at cost less any impairment and adjusted for certain observable price changes. The Update also requires a qualitative impairment assessment of such equity investments and amends certain fair value disclosure requirements. The new standard becomes effective for fiscal years beginning after December 15, 2017. Early adoption is only permitted for the provision related to instrument-specific credit risk and the fair value disclosure exemption provided to nonpublic entities. The Company is currently evaluating the effects of adopting ASU 2016-01 on its consolidated financial statements but the adoption is not expected to have a significant impact on the Company's consolidated financial statements.

NOTE 2 - OIL AND GAS PROPERTIES, EQUIPMENT AND FIXTURES

Oil and gas properties, equipment and fixtures consist of the following at December 31:

	2015	2014
Oil and Gas		
Producing properties, including intangible drilling costs	$ 5,217,637	$ 4,920,521
Undeveloped properties	2,381,564	2,773,422
Lease and well equipment	4,339,122	4,410,120
	11,938,323	12,104,063
Accumulated depletion, depreciation and amortization	(7,656,731)	(7,318,510)
	$ 4,281,592	$ 4,785,553
Commercial and Other	2015	2014
Real estate, including furniture and fixtures	$ 2,266,050	$ 2,768,394
Vehicles	118,061	116,830
Furniture and equipment	1,120,760	1,114,086
	3,504,871	3,999,310
Accumulated depreciation	(1,253,985)	(1,190,197)
	2,250,886	2,809,113
	$ 6,532,478	$ 7,594,666

The following sets forth costs incurred for oil and gas property acquisition and development activities, whether capitalized or expensed:

	2015	2014
Acquisition - Proved	$ 69,446	3,215
Acquisition- Unproved	$ 113,749	84,715
Development	$ 672,651	1,346,433
Exploration	$ 1,845,585	2,309,105

The guidance set forth in the Continued Capitalization of Exploratory Well Costs paragraph of the Extractive Activities Topic of the FASB Accounting Standards Codification requires that we evaluate all existing capitalized exploratory well costs and disclose the extent to which any such capitalized costs have become impaired and are expensed or reclassified during a fiscal period. We did not make any additions to capitalized exploratory well costs pending a determination of proved reserves during 2015 or 2014. We did not charge any previously capitalized exploratory well costs to expense upon adoption of Topic. Undeveloped properties are not subject to depletion, depreciation or amortization.

	12 Months Ended December 31, 2015	2014
Beginning balance at January 1	$ -	$ -
Additions to capitalized exploratory well costs pending the determination of proved reserves	$ 85,640	$ 188,017
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	$ (85,640)	$ (188,017)
Ending balance at December 31	$ -	$ -

Results of Operations from Oil and Gas Producing and Exploration Activities

The results of operations from oil and gas producing and exploration activities (excluding corporate overhead and interest costs) for the two years ended December 31, are as follows:

	2015	2014
Oil and gas sales	$ 1,018,928	2,598,297
Production related costs	(1,449,082)	(2,044,479)
Lease Impairment	(424,163)	(268,093)
Depreciation, depletion and amortization	(400,813)	(315,574)
Results of operations from producing and exploration activities	$ (1,255,130)	(29,849)
Income Taxes (Benefit)	-	-
Net Results	$ (1,255,130)	(29,849)

NOTE 3 – ASSET RETIREMENT OBLIGATION

The Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset. The ARO is recorded at fair value, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at the Company's credit-adjusted risk-free interest rate. The provisions of this Topic apply to legal obligations associated with the retirement of long-lived assets that result from the acquisition, development, and operation of a long-lived asset.

	2015	2014
Asset retirement obligation, Beginning of the year	$ 804,206	$ 862,369
Liabilities incurred during the period	321,560	7,638
Settlements	(68,360)	(66,304)
Accretion expense	38,773	503
Asset retirement obligation, End of year	$ 1,096,179	$ 804,206

NOTE 4 - TURNKEY DRILLING OBLIGATION

Royale Energy receives funds under turnkey drilling contracts, which require Royale Energy to drill oil and gas wells within a reasonable time period from the date of receipt of the funds. As of December 31, 2015 and 2014, Royale Energy had recorded deferred turnkey drilling associated with undrilled wells of $8,415,528 and $7,937,786, respectively, as a current liability.

NOTE 5 - LONG-TERM DEBT

	2015	2014
On December 24, 2013, Royale Energy, Inc. entered into an agreement between the Company, as buyer, and North Island Financial Credit Union as seller, for the purchase of commercial property in San Diego, California, for a purchase price of $2,000,000, of which $500,000 was paid in cash on the date of purchase, and $1,500,000 was borrowed from AmericanWest Bank, NA, with a note secured by the property being purchased. The note carries an interest rate of 5.75% until paid in full. Royale will pay this loan in 119 regular payments of $9,525 each and one balloon payment estimated at $1,150,435. Royale's first payment was due February 1, 2014, and all subsequent payments are due on the same day of each month after that. Royale's final payment will be due on January 1, 2024, and will be for all principal and all accrued interest not yet paid. Payments include principal and interest. Stephen M Hosmer, President, CFO is named as a personal guarantor of the loan. The loan agreement contains certain covenants that, among other things, Royale must maintain a ratio of EBITDA-Debt Service Coverage in excess of 1.50 to 1.00. At December 31, 2015, Royale was not in compliance with this covenant, but obtained a forbearance from the bank from terms of that covenant to May 26, 2016. The Company is currently in the process of finalizing the sale of the office building and associated land, which is expected to resulting full payment of the long-term debt. However, there is no guarantee that the sale will be completed.	$ 1,446,853	$ 1,475,884
Total Long Term Debt	$ 1,446,853	$ 1,475,884
Less Current Maturity	30,528	$ 29,031
Long Term Debt Less Current Portion	$ 1,416,325	$ 1,446,853

Maturities of long-term debt for the years subsequent to December 31, 2015 are as follows:

Year Ended December 31,		
2016	$	30,528
2017	$	32,597
2018	$	34,549
2019	$	36,618
Thereafter	$	1,312,561
Total	$	1,446,853

NOTE 6 - INCOME TAXES

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

Significant components of the Company's deferred assets and liabilities at December 31, 2015 and 2014, respectively, are as follows:

		2015		2014
Deferred Tax Assets (Liabilities):				
Statutory Depletion Carry Forward	$	555,093	$	672,480
Net Operating Loss		4,651,428		4,568,737
Other		1,247,829		939,061
Share-Based Compensation		96,536		70,921
Capital Loss / AMT Credit Carry Forward		18,915		76,410
Charitable Contributions Carry Forward		21,644		16,602
Allowance for Doubtful Accounts		887,418		681,052
Oil and Gas Properties and Fixed Assets		4,980,324		4,828,214
	$	12,459,187	$	11,853,477
Valuation Allowance		(12,459,187)		(11,853,477)
Net Deferred Tax Asset	$	-	$	-
Deferred Tax Assets:				
Current	$	150,845	$	126,499
Non-current		(150,845)		(126,499)
Deferred Tax Liabilities:				
Current				
Non-current				
Net Deferred Tax Asset	$	-	$	-

At the end of 2014, management reviewed the realizability of the Company's net deferred tax assets. Due to the Company's cumulative losses in recent years, Royale and its management concluded that it is not "more-likely-than-not" its deferred tax assets will be realized. As a result, the Company recorded a full valuation allowance against the net deferred tax assets in 2014. At the end of 2015, management reviewed the reliability of the Company's net deferred tax assets, and due to the Company's continued cumulative losses in recent years, Royale and its management concluded it is not "more-likely-than-not" its deferred tax assets will be realized. As a result, the Company will continue to record a full valuation allowance against the deferred tax assets in 2015. The Company will assess the realizability of the deferred tax assets at least yearly and make appropriate updates as needed. The Company had statutory percentage depletion carry forwards of approximately $1.4 million at December 31, 2015. The depletion has no expiration date. The Company also has a net operating loss carry forward of approximately $11.6 million at December 31, 2015, which will begin to expire in 2027.

A reconciliation of Royale Energy's provision for income taxes and the amount computed by applying the statutory income tax rates at December 31, 2014 and 2013, respectively, to pretax income is as follows:

	2015	2014
Tax (benefit) computed at statutory rate of 34%	$ (683,678)	$ (731,630)
Increase (decrease) in taxes resulting from:		
State tax / percentage depletion / other	957	-
Other non-deductible expenses	1,478	1,665
Change in valuation allowance	681,243	729,965
Provision (benefit)	$ -	$ -

The components of the Company's tax provision are as follows:

	2015	2014
Current tax provision (benefit) – federal	$ -	-
Current tax provision (benefit) – state	-	-
Deferred tax provision (benefit) – federal	-	-
Deferred tax provision (benefit) – state	-	-
Total provision (benefit)	$ -	-

In January 2007, Royale adopted additional provisions from the Income Taxes Topic of the FASB Accounting Standards Codification, which clarified the accounting for uncertainty in income taxes recognized in an entity's financial statements and prescribes a recognition threshold and measurement attribute for financial statement disclosure of tax positions taken or expected to be taken on a tax return. As a result of our implementation of the Topic at the time of adoption and at December 31, 2015, the Company did not recognize a liability for uncertain tax positions. Currently, the only differences between our financial statements and our income tax returns relate to normal timing differences such as depreciation, depletion and amortization, which are recorded as deferred taxes on our balance sheets. We do not expect our unrecognized tax benefits to change significantly over the next 12 months. The tax years 2011 through 2014 remain open to examination by the taxing jurisdictions in which we file income tax returns.

NOTE 7 - SERIES AA PREFERRED STOCK

In April 1992, Royale Energy's Board of Directors authorized the sale of 147,500 shares of Series AA Convertible Preferred Stock. Holders of Series AA Convertible Preferred Stock have dividend, conversion and preference rights identical to Series A Convertible Preferred Stockholders. The Series AA Convertible Preferred Stock has a stated value of $4 per share and provides shareholders with a one-time dividend payable equal to forty cents ($0.40) per share of Series AA Convertible Preferred Stock within thirty days after the expiration of one year from the date of purchase. The dividend has been paid on all outstanding shares as of December 31, 1994.

The Series AA Convertible Preferred Stock is convertible any time at the basic conversion rate of one share of common stock for two shares of Series AA Convertible Preferred Stock, subject to adjustment. Royale Energy has the option to call, at any time after six months from the issuance, the Series AA Convertible Preferred Stock at either the issue price of $4 per share plus 10%, if called within one year after issuance, or $4 per share thereafter. (Subject to the holders' conversion rights outlined above). The Series AA Convertible Preferred Stock has a liquidation preference to the common stock equal to $4 per share plus accrued dividends. In the event of any voluntary or involuntary liquidation, dissolution or winding up of the Corporation, the holders of the shares of the Series AA Convertible Preferred Stock shall be entitled to be paid out of the assets of the Corporation available for distribution to its shareholders before any payment shall be made in respect of the Corporation's common stock, but only after payment to its creditors, an amount equal to $4.40 per share, if called within one year after issuance, or $4 per share thereafter. Holders of Series AA Convertible Preferred Stock shall have voting rights equal to the number of shares of common stock into which the Series AA Convertible Preferred Stock may be converted.

The Series AA Convertible Preferred Stock does not have the right of redemption at the stockholders' option. The preferred stock is not registered under the Securities Exchange Act of 1934, and no market exists for the preferred stock. The shares of Series AA Preferred stock are convertible into shares of Royale Energy's common stock at the option of the security holder, at the rate of two shares of convertible preferred stock for each share of common stock. During the year ending December 31, 2014, there was a conversion of 6,122 Series AA Preferred shares, with a book value of $17,865, for 3,061 common shares. There were no such conversions during 2015. As of December 31, 2015 and 2014, and there were 46,662 and 46,662 shares, respectively of Series AA Preferred stock issued and outstanding.

NOTE 8 - COMMON STOCK

In May 2015 and April 2014, Royale Energy entered into Sales Agreements with Roth Capital Partners, LLC (Roth), under which the Company had the ability to issue and sell shares of its common stock from time to time in an at the market equity offering program with Roth acting as the Company's sales agent. Royale Energy sold 701,397 shares of common stock for total consideration of $556,123 under the 2015 Sales Agreement and no shares of common stock under the 2014 Sales Agreement. Both agreements have been terminated as of December 31, 2015.

On November 25, 2015, Royale Energy entered into a securities purchase agreement and related agreements with a group of individual investors pursuant to a registered direct offering. Under the terms of the agreements, the investors purchased 497,948 shares of Royale's common stock at $0.408 per share, and received warrants to purchase up to 248,973 shares (the "Warrants') of stock at $1.00 per share for three (3) years, for a total of $203,165 in gross proceeds,. Each Warrant becomes exercisable one year from the date of issuance. Each Warrant contains customary adjustments for corporate events such as reorganizations, splits, and dividends. The fair value of each warrant was estimated on the grant date using the Black-Scholes option-pricing model. This model incorporates certain assumptions for inputs including a risk-free market interest rate, expected dividend yield of the underlying common stock, expected warrant life and expected volatility in the market value of the underlying common stock. For these warrants, the value was calculated with the following assumptions: expected volatility of 78.96%, risk-free market interest rate of 1.13%, an expected term of 1,460 days, and an exercise price of $1.00.

NOTE 9 - OPERATING LEASES

Royale rents an office and yard in Woodland, CA on a month-to-month basis that currently calls for monthly payments of $500. Rental expense for the years ended December 31, 2015 and 2014 was $10,400 and $74,047 respectively.

NOTE 10 - RELATED PARTY TRANSACTIONS

Significant Ownership Interests

As of February 23, 2016, Donald H. Hosmer, Royale Energy's co-president and co-chief executive officer owns 8.08% of Royale Energy common stock. Donald H. Hosmer is the brother of Stephen M. Hosmer, and son of Harry E. Hosmer. Donald has participated individually in 178 wells under the 1989 policy. During 2015, Donald participated in fractional interests of two wells in the amount of $3,143 and in 2014 participated in fractional interests of four wells in the amount of $18,692. At December 31, 2015, Royale had a receivable balance of $991 due from Donald Hosmer for normal drilling and lease operating expenses.

As of February 23, 2016, Stephen M. Hosmer, Royale Energy's co-president, co-chief executive officer and chief financial officer, owns 7.89% of Royale Energy common stock. Stephen M. Hosmer is the brother of Donald H. Hosmer and son of Harry E. Hosmer. Stephen has participated individually in 178 wells under the 1989 policy. During 2015, Stephen participated in fractional interests of four wells in the amount of $4,389 and in 2014 participated in fractional interests of four wells in the amount of $7,714. At December 31, 2015, Royale had a receivable balance of $7,696 due from Stephen Hosmer for normal drilling and lease operating expenses.

As of February 23, 2016, Harry E. Hosmer, Royale Energy's former president and former chief executive officer, owns 4.41% of Royale Energy common stock. Donald H. and Stephen M. Hosmer are sons of Harry E. Hosmer. Donald H. Hosmer and Stephen M. Hosmer are also officers and directors of Royale Energy. Harry Hosmer also assists Royale Energy on a consulting basis and receives $13,805 monthly for these services. During 2015, Harry Hosmer participated in fractional interests of four wells in the amount of $5,633 and in 2014 participated in fractional interests of three wells in the amount of $9,985. At December 31, 2015, Royale had a receivable balance of $4,380 due from Harry Hosmer for normal drilling and lease operating expenses.

NOTE 11 - STOCK COMPENSATION PLAN

During the Board of Directors meeting held in December 2010, directors and executive officers of Royale Energy were each granted 50,000 stock options, a total of 400,000 options, to purchase common stock at an exercise or base price of $3.25 per share. These options vested in two parts; the first 200,000 options vested on January 1, 2012; the remaining 200,000 options vested on January 1, 2013. The options were granted with a legal life of five years, and a service period of two years beginning January 1, 2012. In 2013, Royale did not recognize any compensation costs or tax effect related to this grant.

During the October 10, 2014 Board of Directors meeting, directors and executive offices of Royale Energy were granted 20,000 options each, 140,000 total, to purchase common stock at an exercise price of $5.00 per share. These options were granted for a period of 3 years and will expire on December 31, 2017. These options became exercisable at 5,000 shares per period beginning October 13, 2014, January 1, 2015, April 1, 2015 and July 1 2015. During 2015 and 2014, Royale recognized compensation costs of $86,877 and $33,785, respectively, relating to this option grant. There were no stock options granted during 2015.

The fair value of each option is estimated on the date of grant using the Black-Scholes option-pricing model. This model incorporates certain assumptions for inputs including a risk-free market interest rate, expected dividend yield of the underlying common stock, expected option life and expected volatility in the market value of the underlying common stock. There were 0 and 140,000 options granted in the years ended December 31, 2015 and 2014, respectively. The 2014 options were granted with the following assumptions:

Options	2015	2014
Expected volatility	-	81.33%
Weighted-average volatility	-	81.33%
Expected dividends	-	-
Expected term (months)	-	39
Risk-free rate	-	.57%

Since, at the time of option grant, there was currently no market for options of Royale's common stock, expected volatilities are based on historical volatility of the Company's common stock and other factors. The risk-free rate for the periods within the contractual life of the option is based on quoted market yields for U.S. Treasury debt securities. The expected dividend yield was zero as the Company was subject to debt covenant prohibiting the payment of dividends. Royale Energy uses historical data to estimate option exercise and board member turnover within the valuation model. Compensation expense related to stock options was recorded net of estimated forfeitures, which for options remaining at December 31, 2016, Royale expects no additional forfeitures.

A summary of the status of Royale Energy's stock option plan as of December 31, 2015 and 2014, and changes during the years ending on those dates is presented below:

	2015		2014	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Options				
Outstanding and Exercisable at Beginning of Year	281,308	$ 3.47	346,308	$ 3.25
Granted or Vested	100,000	5.00	35,000	5.00
Exercised	-	-	-	-
Forfeited	(281,308)	-	(100,000)	-
Options Outstanding and Exercisable at Year End	100,000	$ 5.00	281,308	$ 3.47
Weighted-average Fair Value of Options Granted During the Year	$ -		$ -	

At December 31, 2015, Royale Energy's stock price, $0.36, was less than the weighted average exercise price, and as such the outstanding and exercisable stock options had no intrinsic value. The stock options granted in 2014 have a weighted-average remaining contractual term of two years as of December 31, 2015. There were no stock options granted during 2015.

A summary of the status of Royale Energy's non-vested stock options as of December 31, 2015 and 2014, and changes during the years ending on those dates is presented below:

	2015		2014	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Non-vested Stock Options				
Non-vested at Beginning of Year	105,000	$ 0.97	-	$ -
Granted	-	-	140,000	0.97
Reinstated	-	-	-	-
Vested	90,000	0.97	35,000	0.97
Expired or Forfeited	15,000	0.97	-	-
Non-vested at End of Year	-	$	105,000	$ 0.97

During 2015 and 2014, we recognized $86,877 and $33,785, respectively, in compensation costs for the vested stock options.

NOTE 12 - SIMPLE IRA PLAN

In April 1998, the Company established a Simple IRA pension plan covering all employees. The Company will contribute a matching contribution to each eligible employee's Simple IRA equal to the employee's salary reduction contributions up to a limit of 3% of the employee's compensation for the year. The employer contribution for the years ending December 31, 2015 and 2014, were $43,001, and $47,081 respectively.

NOTE 13 - ENVIRONMENTAL MATTERS

Royale Energy has established procedures for the continuing evaluation of its operations to identify potential environmental exposures and assure compliance with regulatory policies and procedures. Management monitors these laws and regulations and periodically assesses the propriety of its operational and accounting policies related to environmental issues. The nature of Royale Energy's business requires routine day-to-day compliance with environmental laws and regulations. Royale Energy incurred no material environmental investigation, compliance and remediation costs in 2015 or 2014.

Royale Energy is unable to predict whether its future operations will be materially affected by these laws and regulations. It is believed that legislation and regulations relating to environmental protection will not materially affect the results of operations of Royale Energy.

NOTE 14 - CONCENTRATIONS OF CREDIT RISK

The Company bids its gas sales on a month to month basis and generally sells to a single customer without commitment to future gas sales to any particular customer. The Company normally sells approximately 87% of its monthly natural gas production to one customer on a month to month basis. Since we are able to sell our natural gas to other readily available customers, the loss of any one customer would not have an adverse effect on our overall sales operations.

The Company maintains cash in depository institutions that are guaranteed by the Federal Deposit Insurance Corporation (FDIC) up to $250,000 per institution for our interest bearing accounts in the years ended December 31, 2015, and 2014. At December 31, 2015, and 2014, the Company's non-interest bearing accounts were fully insured by the FDIC. At December 31, 2015 and 2014, cash in banks exceeded the FDIC limits by approximately $3.4 million and $2.8 million, respectively. The Company has not experienced any losses on deposits.

NOTE 15 - COMMITMENTS AND CONTINGENCIES

The Company may become involved from time to time in litigation on various matters, which are routine to the conduct of its business. The Company believes that none of these actions, individually or in the aggregate, will have a material adverse effect on its financial position or results of operations, though any adverse decision in these cases or the costs of defending or settling such claims could have a material effect on its business.

NOTE 16 – SUBSEQUENT EVENTS

On February 11, 2016, Royale Energy, Inc. entered into a purchase and sale agreement for the sale of its corporate headquarters building located in El Cajon, California for $2.5 million. The buyer is currently conducting its due diligence process.

Pursuant to the Form S-8 filed with the Securities and Exchange Commission on December 15, 2015 (File No. 333-208555), Royale Energy, Inc. has issued 1,220,084 shares of Royale Energy, Inc. common stock valued at $163,437 to its directors and offices as a portion of their compensation from January 2016 through the date of filing. The shares were valued at the closing market price on the date of grant, and were instead of their cash compensation. Since the Form S-8 was filed in December 2015, Royale has issued 1,405,821 shares of Royale Energy, Inc. common stock valued at $251,805 to it directors and officer under this registration statement.

ROYALE ENERGY, INC.

SUPPLEMENTAL INFORMATION ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests owned by Royale Energy which are located solely in the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate to be reasonably certain to be recoverable in the future from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells, with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves, which follow, are based on estimates prepared by independent petroleum engineering consultant Netherland, Sewell & Associates, Inc., the net reserve value of its proved developed and undeveloped reserves was approximately $3.2 million at December 31, 2015, based on natural gas prices ranging from $2.59 per MCF to $2.98 per MCF as applied on a field-by-field basis. Netherland, Sewell & Associates, Inc. provided reserve value information for the Company’s California, Texas, Oklahoma, Utah and Louisiana properties. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves.

The technical persons responsible for preparing the reserves estimates presented in the report of Netherland, Sewell & Associates, Inc., meet the requirements regarding 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. Netherland, Sewell & Associates, Inc. is a firm of independent petroleum engineers, geologists, geophysicists, and petrophysicists; and do not own an interest in our properties and are not employed on a contingent basis. All activities and reports performed and completed by Netherland, Sewell & Associates, Inc. with regards to our reserve valuation estimates are reviewed Royale’s management.

These estimates are furnished and calculated in accordance with requirements of the Financial Accounting Standards Board and the Securities and Exchange Commission (SEC). Because of unpredictable variances in expenses and capital forecasts, crude oil and natural gas price changes, largely influenced and controlled by U.S. and foreign government actions, and the fact that the bases for such estimates vary significantly, management believes the usefulness of these projections is limited. Estimates of future net cash flows presented do not represent management's assessment of future profitability or future cash flows to Royale Energy. Management's investment and operating decisions are based upon reserve estimates that include proved reserves prescribed by the SEC as well as probable reserves, and upon different price and cost assumptions from those used here.

It should be recognized that applying current costs and prices and a 10 percent standard discount rate does not convey absolute value. The discounted amounts arrived at are only one measure of the value of proved reserves.

Changes in Estimated Reserve Quantities

The net interest in estimated quantities of proved developed reserves of crude oil and natural gas at December 31, 2015 and 2014, and changes in such quantities during each of the years then ended, were as follows:

	2015		2014	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved developed and undeveloped reserves:				
Beginning of period	1,781	4,131,806	38,265	3,914,250
Revisions of previous estimates	(178)	(1,323,741)	(35,799)	(101,944)
Production	(403)	(363,168)	(685)	(547,898)
Extensions, discoveries and improved recovery	-	48,912	-	867,398
Purchase of minerals in place	2,400	16,900	-	-
Sales of minerals in place	-	-	-	-
Proved reserves end of period	3,600	2,510,700	1,781	4,131,806

	2015		2014	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved developed reserves:				
Beginning of period	587	3,786,785	5,984	3,168,142
End of period	-	2,174,100	587	3,786,785

	2015		2014	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved undeveloped reserves:				
Beginning of period	1,194	345,021	32,281	746,108
End of period	3,600	336,600	1,194	345,021

For December 31, 2015, natural gas extensions, discoveries and improved recovery were 48,912 MCF which was added due to the drilling one new exploratory well during 2015. This new well consisted of 4,312 MCF of proved developed producing reserves and 44,600 proved developed non-producing reserves. A location which had 658,894 MCF in proved developed reserves at December 31, 2014, was drilled and began producing in 2014, was revised downward 566,405 MCF at December 31, 2015. A location which was drilled in 2011 and began producing in 2013, was revised downward 135,729 MCF at December 31, 2015. A location which was drilled and began producing in 2012, had proved developed producing reserves of 229,287 at December 31, 2014, was revised downward 184,436 MCF at December 31, 2015. A location which was drilled and began producing in 2013, had proved developed producing reserves of 111,445 at December 31, 2014, was revised downward 80,486 MCF at December 31, 2015. Additionally in 2015, four locations which were drilled prior to 2011, had a total of 905,646 MCF of proved developed reserves at December 31, 2014, were revised downward 306,366 MCF at December 31, 2015.

For December 31, 2014, natural gas extensions, discoveries and improved recovery came to 867,398 MCF which were added due to the drilling two new exploratory wells during 2014. These new wells consisted of 644,553 MCF of proved developed producing reserves and 222,845 proved developed non-producing reserves. A location which was drilled in 2011 and began producing in 2013, was revised upward 251,800 MCF at December 31, 2014. A location which had 395,760 MCF in proved undeveloped reserves at December 31, 2013, was drilled and began producing in 2014, was revised downward 321,703 MCF at December 31, 2014. A location which was drilled and began producing in 2013, had proved developed producing reserves of 196,162 at December 31, 2013, was revised downward 187,540 MCF at December 31, 2014. Additionally in 2014, two locations which had a total of 32,282 BBL of proved undeveloped reserves at December 31, 2013, were revised downward 31,088 BBL at December 31, 2014.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows is presented below for the two years ended December 31, 2015.

The future net cash inflows are developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.
- The estimated future production of proved reserves is priced on the basis of year-end prices.
- The resulting future gross revenue streams are reduced by estimated future costs to develop and to produce proved reserves, based on year-end estimates. Estimated future development costs by year are as follows:

2016	$	197,000
2017		376,700
2018		-
Thereafter		89,100
Total	$	662,800

The resulting future net revenue streams are reduced to present value amounts by applying a ten percent discount.

Disclosure of principal components of the standardized measure of discounted future net cash flows provides information concerning the factors involved in making the calculation. In addition, the disclosure of both undiscounted and discounted net cash flows provides a measure of comparing proved oil and gas reserves both with and without an estimate of production timing. The standardized measure of discounted future net cash flow relating to proved reserves reflects estimated income taxes.

Changes in standardized measure of discounted future net cash flow from proved reserve quantities

This statement discloses the sources of changes in the standardized measure from year to year. The amount reported as “Net changes in prices and production costs” represents the present value of changes in prices and production costs multiplied by estimates of proved reserves as of the beginning of the year. The “accretion of discount” was computed by multiplying the ten percent discount factor by the standardized measure on a pretax basis as of the beginning of the year. The “Sales of oil and gas produced, net of production costs” are expressed in actual dollar amounts. “Revisions of previous quantity estimates” is expressed at year-end prices. The “Net change in income taxes” is computed as the change in present value of future income taxes.

		2015	2014
Future cash inflows	$	6,962,900	19,919,930
Future production costs		(3,066,200)	(6,860,440)
Future development costs		(662,800)	(648,000)
Future income tax expense		(970,170)	(3,723,477)
Future net cash flows		2,263,730	8,688,013
10% annual discount for estimated timing of cash flows		(704,014)	(2,072,974)
Standardized measure of discounted future net cash flows	$	1,559,716	6,615,039
Sales of oil and gas produced, net of production costs	$	(155,847)	(936,266)
Revisions of previous quantity estimates		(5,089,087)	1,082,838
Net changes in prices and production costs		(2,238,956)	(708,607)
Sales of minerals in place		-	-
Purchases of minerals in place		6,000	-
Extensions, discoveries and improved recovery		36,000	1,234,621
Accretion of discount		220,000	740,292
Net change in income tax		2,166,567	(849,028)
Net increase (decrease)	$	(5,055,323)	1,981,064

Future Development Costs

In order to realize future revenues from our proved reserves estimated in our reserve report, it will be necessary to incur future costs to develop and produce the proved reserves. The following table estimates the costs to develop and produce our proved reserves in the years 2016 through 2018.

Future development cost of:	2016	2017	2018
Proved developed reserves	$ -	$ -	$ -
Proved non-producing reserves	114,200	34,000	-
Proved undeveloped reserves	82,800	342,700	-
Total	$ 197,000	$ 376,700	$ -

Common assumptions include such matters as the real extent and average thickness of a particular reservoir, the average porosity and permeability of the reservoir, the anticipated future production from existing and future wells, future development and production costs and the ultimate hydrocarbon recovery percentage. As a result, oil and gas reserve estimates and discounted present value estimates are frequently revised in subsequent periods to reflect production data obtained after the date of the original estimate. If the reserve estimates are inaccurate, production rates may decline more rapidly than anticipated, and future production revenues may be less than estimated.

Additional data relating to Royale Energy's oil and natural gas properties is disclosed in Supplemental Information About Oil and Gas Producing Activities (Unaudited), attached to Royale Energy's Financial Statements, beginning on page F-1

Historic Development Costs for Proved Reserves

In each year we expend funds to drill and develop some of our proved undeveloped reserves. The following table summarizes our historic costs incurred in each of the past three fiscal years to drill and develop reserves that were classified as proved undeveloped reserves as of December 31 of the immediately preceding year:

2015	$	-
2014	$	549,236

Exhibit 10.5

PROMISSORY NOTE

Principal	Loan Date	Maturity	Loan No	Call / Coll	Account	Officer	Initials
$1,500,000.00	12-23-2013	01-01-2024	990011185	1E1 / 2,33		BH	

References in the boxes above are for Lender's use only and do not limit the applicability of this document to any particular loan or item. Any item above containing "***" has been omitted due to text length limitations.

Borrower: Royale Energy, Inc.
7676 Hazard Center Drive Ste 1500
San Diego, CA 92108

Lender: AMERICANWEST BANK
SAN DIEGO COMMERCIAL BANKING
4445 EASTGATE MALL, SUITE 110
SAN DIEGO, CA 92121
(858) 625-9050

Principal Amount: $1,500,000.00 **Date of Note: December 23, 2013**

PROMISE TO PAY. Royale Energy, Inc. ("Borrower") promises to pay to AMERICANWEST BANK ("Lender"), or order, in lawful money of the United States of America, the principal amount of One Million Five Hundred Thousand & 00/100 Dollars ($1,500,000.00), together with interest on the unpaid principal balance from December 23, 2013, calculated as described in the "INTEREST CALCULATION METHOD" paragraph using an interest rate of 5.750%, until paid in full. The interest rate may change under the terms and conditions of the "INTEREST AFTER DEFAULT" section.

PAYMENT. Borrower will pay this loan in 119 regular payments of $9,525.08 each and one irregular last payment estimated at $1,150,434.73. Borrower's first payment is due February 1, 2014, and all subsequent payments are due on the same day of each month after that. Borrower's final payment will be due on January 1, 2024, and will be for all principal and all accrued interest not yet paid. Payments include principal and interest. Unless otherwise agreed or required by applicable law, payments will be applied first to any accrued unpaid interest; then to principal; then to any escrow or reserve account payments as required under any mortgage, deed of trust, or other security instrument or security agreement securing this Note; then to any unpaid collection costs; and then to any late charges.

INTEREST CALCULATION METHOD. Interest on this Note is computed on a 365/360 basis; that is, by applying the ratio of the interest rate over a year of 360 days, multiplied by the outstanding principal balance, multiplied by the actual number of days the principal balance is outstanding. All interest payable under this Note is computed using this method. This calculation method results in a higher effective interest rate than the numeric interest rate stated in this Note.

RECEIPT OF PAYMENTS. All payments must be made in U.S. dollars and must be received by Lender consistent with the following payment instructions: In-person payments may be made at any of Lender's branches. Please mail payments to: AmericanWest Bank, 110 South Ferrall Street, Spokane, WA 99202. Arrangements may also be made to automate payments from a deposit account.
Lender may modify these payment instructions by providing updated payment instructions to Borrower in writing.

PREPAYMENT FEE. Borrower agrees that all loan fees and other prepaid finance charges are earned fully as of the date of the loan and will not be subject to refund upon early payment (whether voluntary or as a result of default), except as otherwise required by law. Upon prepayment of this Note, Lender is entitled to the following prepayment fee: Subject to the prepayment indemnity fee herein described, Borrower may prepay all or a portion of the amount owed earlier than it is due. If $100,000.00 or more is prepaid during any of the first five years of the loan, the following prepayment indemnity fee shall apply to the entire principal amount that is prepaid during each respective year of the loan: 5% during the first year; 4% during the second year; 3% during the third year; 2% during the fourth year and 1% during the fifth year. Said fee may, at Lender's sole discretion, be taken as a reduction of the principal payment or separately billed. . Except for the foregoing, Borrower may pay all or a portion of the amount owed earlier than it is due. Early payments will not, unless agreed to by Lender in writing, relieve Borrower of Borrower's obligation to continue to make payments under the payment schedule. Rather, early payments will reduce the principal balance due and may result in Borrower's making fewer payments. Borrower agrees not to send Lender payments marked "paid in full", "without recourse", or similar language. If Borrower sends such a payment, Lender may accept it without losing any of Lender's rights under this Note, and Borrower will remain obligated to pay any further amount owed to Lender. All written communications concerning disputed amounts, including any check or other payment instrument that indicates that the payment constitutes "payment in full" of the amount owed or that is tendered with other conditions or limitations or as full satisfaction of a disputed amount must be mailed or delivered to: AMERICANWEST BANK, LOAN ADMINISTRATION, 110 South Ferrall SPOKANE, WA 99202-4800.

LATE CHARGE. If a payment is 15 days or more late, Borrower will be charged 5.000% of the unpaid portion of the regularly scheduled payment or $100.00, whichever is greater.

INTEREST AFTER DEFAULT. Upon default, the interest rate on this Note shall, if permitted under applicable law, immediately become 21.000%.

DEFAULT. Each of the following shall constitute an event of default ("Event of Default") under this Note:

Payment Default. Borrower fails to make any payment when due under this Note.

Other Defaults. Borrower fails to comply with or to perform any other term, obligation, covenant or condition contained in this Note or in any of the related documents or to comply with or to perform any term, obligation, covenant or condition contained in any other agreement between Lender and Borrower.

Default in Favor of Third Parties. Borrower or any Grantor defaults under any loan, extension of credit, security agreement, purchase or sales agreement, or any other agreement, in favor of any other creditor or person that may materially affect any of Borrower's property or Borrower's ability to repay this Note or perform Borrower's obligations under this Note or any of the related documents.

Environmental Default. Failure of any party to comply with or perform when due any term, obligation, covenant or condition contained in any environmental agreement executed in connection with any loan.

False Statements. Any warranty, representation or statement made or furnished to Lender by Borrower or on Borrower's behalf under this Note or the related documents is false or misleading in any material respect, either now or at the time made or furnished or becomes false or misleading at any time thereafter.

Insolvency. The dissolution or termination of Borrower's existence as a going business, the insolvency of Borrower, the appointment of a receiver for any part of Borrower's property, any assignment for the benefit of creditors, any type of creditor workout, or the commencement of any proceeding under any bankruptcy or insolvency laws by or against Borrower.

Creditor or Forfeiture Proceedings. Commencement of foreclosure or forfeiture proceedings, whether by judicial proceeding, self-help, repossession or any other method, by any creditor of Borrower or by any governmental agency against any collateral securing the loan. This includes a garnishment of any of Borrower's accounts, including deposit accounts, with Lender. However, this Event of Default shall not apply if there is a good faith dispute by Borrower as to the validity or reasonableness of the claim which is the basis of the creditor or forfeiture proceeding and if Borrower gives Lender written notice of the creditor or forfeiture proceeding and deposits with Lender monies or a surety bond for the creditor or forfeiture proceeding, in an amount determined by Lender, in its sole discretion, as being an adequate reserve or bond for the dispute.

Events Affecting Guarantor. Any of the preceding events occurs with respect to any Guarantor of any of the indebtedness or any Guarantor dies or becomes incompetent, or revokes or disputes the validity of, or liability under, any guaranty of the indebtedness evidenced by this Note.

Change In Ownership. Any change in ownership of twenty-five percent (25%) or more of the common stock of Borrower.

Adverse Change. A material adverse change occurs in Borrower's financial condition, or Lender believes the prospect of payment or performance of this Note is impaired.

Insecurity. Lender in good faith believes itself insecure.

Cure Provisions. If any default, other than a default in payment is curable and if Borrower has not been given a notice of a breach of the same provision of this Note within the preceding twelve (12) months, it may be cured if Borrower, after Lender sends written notice to Borrower demanding cure of such default: (1) cures the default within fifteen (15) days; or (2) if the cure requires more than fifteen (15) days, immediately initiates steps which Lender deems in Lender's sole discretion to be sufficient to cure the default and thereafter continues and completes all reasonable and necessary steps sufficient to produce compliance as soon as reasonably practical.

LENDER'S RIGHTS. Upon default, Lender may declare the entire unpaid principal balance under this Note and all accrued unpaid interest immediately due, and then Borrower will pay that amount.

ATTORNEYS' FEES; EXPENSES. Lender may hire or pay someone else to help collect this Note if Borrower does not pay. Borrower will pay Lender that amount. This includes, subject to any limits under applicable law, Lender's attorneys' fees and Lender's legal expenses, whether or not there is a lawsuit, including attorneys' fees, expenses for bankruptcy proceedings (including efforts to modify or vacate any automatic stay or injunction), and appeals. Borrower also will pay any court costs, in addition to all other sums provided by law.

GOVERNING LAW. This Note will be governed by federal law applicable to Lender and, to the extent not preempted by federal law, the laws of the State of California without regard to its conflicts of law provisions. This Note has been accepted by Lender in the State of California.

CHOICE OF VENUE. If there is a lawsuit, Borrower agrees upon Lender's request to submit to the jurisdiction of the courts of SAN DIEGO County, State of California.

DISHONORED ITEM FEE. Borrower will pay a fee to Lender of $25.00 if Borrower makes a payment on Borrower's loan and the check or preauthorized charge with which Borrower pays is later dishonored.

COLLATERAL. Borrower acknowledges this Note is secured by the following collateral described in the security instruments listed herein:

(A) a Deed of Trust dated December 23, 2013, to a trustee in favor of Lender on real property located in San Diego County, State of California. That agreement contains the following due on sale provision: Lender may, at Lender's option, declare immediately due and payable all sums secured by the Deed of Trust upon the sale or transfer, without Lender's prior written consent, of all or any part of the Real Property, or any interest in the Real Property. A "sale or transfer" means the conveyance of Real Property or any right, title or interest in the Real Property; whether legal, beneficial or equitable; whether voluntary or involuntary; whether by outright sale, deed, installment sale contract, land contract, contract for deed, leasehold interest with a term greater than three (3) years, lease-option contract, or by sale, assignment, or transfer of any beneficial interest in or to any land trust holding title to the Real Property, or by any other method of conveyance of an interest in the Real Property. If any Borrower is a corporation, partnership or limited liability company, transfer also includes any change in ownership of more than twenty-five percent (25%) of the voting stock, partnership interests or limited liability company interests, as the case may be, of such Borrower. However, this option shall not be exercised by Lender if such exercise is prohibited by applicable law.

(B) an Assignment of All Rents to Lender on real property located in San Diego County, State of California.

(C) fixtures described in a Commercial Security Agreement dated December 23, 2013.

ADDITIONAL PROVISION. Borrower agrees to provide Lender financial statements, IRS tax returns and any other financial information deemed necessary at Lender's discretion.

REQUIRED DEPOSIT ACCOUNT. Borrower is required to maintain their primary deposit relationship with AmericanWest Bank during the term of this agreement.

COUNTERPART SIGNATURES. For the convenience of the parties hereto, the Loan Documents may be executed in one or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument.

APPRAISALS. Lender may from time to time order and obtain one or more appraisals on any real property (or any portion thereof) securing the Note ("Real Property"), from an appraiser or appraisers selected by Lender in its sole discretion. Borrower shall cooperate with Lender and any such appraiser in obtaining such appraisal(s). In addition, Borrower shall, at the option of Lender, pay directly for or reimburse Lender for the cost of any such appraisal as follows: (a) if Lender has been required or instructed by its Federal or state regulators to obtain such appraisal; (b) during any time that an Event of Default or a condition that would give rise to an Event of Default (with the passage of time, the giving of notice or otherwise, and regardless of Lender's waiver, forbearance or delay in declaring or enforcing any such Event of Default or condition) exists under this Note, any deed of trust or other loan documents, including without limitation any noncompliance with any financial covenant; or (c) in the event Lender reasonably believes that there has been significant deterioration in (i) the general market conditions for real estate in the area where the Real Property is located, (ii) real estate of the type represented by the Real Property, or (iii) the value of the Real Property (or applicable portion thereof). Borrower's obligation to pay or reimburse the cost of such appraisals under (b) or (c) above shall be limited to once every six months.

SUCCESSOR INTERESTS. The terms of this Note shall be binding upon Borrower, and upon Borrower's heirs, personal representatives, successors and assigns, and shall inure to the benefit of Lender and its successors and assigns.

NOTIFY US OF INACCURATE INFORMATION WE REPORT TO CONSUMER REPORTING AGENCIES. Borrower may notify Lender if Lender reports any inaccurate information about Borrower's account(s) to a consumer reporting agency. Borrower's written notice describing the specific inaccuracy(ies) should be sent to Lender at the following address: AMERICANWEST BANK LOAN ADMINISTRATION 110 South Ferrall SPOKANE, WA 99202-4800.

GENERAL PROVISIONS. If any part of this Note cannot be enforced, this fact will not affect the rest of the Note. Lender may delay or forgo enforcing any of its rights or remedies under this Note without losing them. Borrower and any other person who signs, guarantees or endorses this Note, to the extent allowed by law, waive any applicable statute of limitations, presentment, demand for payment, and notice of dishonor. Upon any change in the terms of this Note, and unless otherwise expressly stated in writing, no party who signs this Note, whether as maker, guarantor, accommodation maker or endorser, shall be released from liability. All such parties agree that Lender may renew or extend (repeatedly and for any length of time) this loan or release any party or guarantor or collateral; or impair, fail to realize upon or perfect Lender's security interest in the collateral; and take any other action deemed necessary by Lender without the consent of or notice to anyone. All such parties also agree that Lender may modify this loan without the consent of or notice to anyone other than the party with whom the modification is made. The obligations under this Note are joint and several.

PRIOR TO SIGNING THIS NOTE, BORROWER READ AND UNDERSTOOD ALL THE PROVISIONS OF THIS NOTE. BORROWER AGREES TO THE TERMS OF THE NOTE.

BORROWER ACKNOWLEDGES RECEIPT OF A COMPLETED COPY OF THIS PROMISSORY NOTE.

BORROWER:

ROYALE ENERGY, INC.

By: ______________________
Stephen Hosmer, Co-President/Secretary of Royale Energy, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement on Form S-3 of Royale Energy, Inc. of our report dated March 14, 2016, relating to our audit of the financial statements, which appear in this Annual Report on Form 10-K of Royale Energy, Inc. for the year ended December 31, 2015.

We also consent to the reference to our Firm under the caption “Experts” in the Prospectus, which is part of this Registration Statement.

SingerLewak LLP

Los Angeles, California
March 14, 2016

Exhibit 23.3

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion of our report of Royale Energy, Inc. (the "Company") dated February 1, 2016, in the Annual Report on Form 10-K for the year ended December 31, 2015, of the Company and its subsidiaries, to be filed with the Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas

March 14, 2016

Exhibit 31.1

I, Jonathan Gregory, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy, Inc.;

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 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.

Date: March 14, 2016

/s/ Jonathan Gregory
Jonathan Gregory, Chief Executive Officer

Exhibit 31.2

I, Stephen M. Hosmer, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy, Inc.;

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 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.

Date: March 14, 2016

/s/ Stephen M. Hosmer
Stephen M. Hosmer, President, and Chief Financial Officer

Exhibit 31.3

I, Donald H. Hosmer, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy, Inc.;

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 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.

Date: March 14, 2016

/s/ Donald H. Hosmer
Donald H. Hosmer, President of Business Development

Exhibit 32.1

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Jonathan Gregory, Chief Executive Officer of Royale Energy, Inc., a California corporation (the "Company"), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company's Quarterly Report on Form 10-K for the period ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) 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 Company.

Date: March 14, 2016 By: /s/ Jonathan Gregory
Jonathan Gregory, Chief Executive Officer

Exhibit 32.2

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Stephen M. Hosmer, President and Chief Financial Officer of Royale Energy, Inc., a California corporation (the "Company"), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company's Annual Report on Form 10-K for the period ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) 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 Company.

Date: March 14, 2016	By:	/s/ Stephen M. Hosmer
		Stephen M. Hosmer, President and Chief Financial Officer

Exhibit 32.3

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Donald H. Hosmer, President of Business Development of Royale Energy, Inc., a California corporation (the "Company"), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company's Quarterly Report on Form 10-K for the period ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) 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 Company.

Date: March 14, 2016	By:	/s/ Donald H. Hosmer
		Donald H. Hosmer, President of Business Development

Exhibit 99.1

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG · MIKE K. NORTON
P. SCOTT FROST · DAN PAUL SMITH
JOHN G. HATTNER · JOSEPH J. SPELLMAN
J. CARTER HENSON, JR. · DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

February 1, 2016

Mr. Kevin Biddick
Royale Energy, Inc.
3777 Willow Glen Drive
El Cajon, California 92019

Dear Mr. Biddick:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2015, to the Royale Energy, Inc. (Royale) interest in certain oil and gas properties located in California, Louisiana, Oklahoma, Texas, and Utah. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Royale. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Royale's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Royale interest in these properties, as of December 31, 2015, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	**Oil (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	0.0	652.3	513.8	404.2
Proved Developed Non-Producing	0.0	1,521.7	2,381.2	1,588.5
Proved Undeveloped	3.6	336.7	338.9	207.3
Total Proved	3.6	2,510.7	3,233.9	2,200.0

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. No study was made to determine whether probable or possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Royale's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Royale's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2015. For oil volumes, the average West Texas Intermediate posted price of $46.79 per barrel is adjusted by lease for quality, transportation fees, and market differentials. For gas volumes, the average PG&E city-gate spot price of $2.978 per MMBTU is used for the California properties and the average Henry Hub spot price of $2.587 per MMBTU is used for all other properties. These average regional spot prices are adjusted by lease for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $47.53 per barrel of oil and $2.706 per MCF of gas.

Operating costs used in this report are based on operating expense records of Royale. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Headquarters general and administrative overhead expenses of Royale are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Royale and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. Our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties. It is our understanding that Royale has fully prefunded accounts that meet or exceed its estimates of abandonment costs for the properties, net of any salvage value.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Royale interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Royale receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Royale, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones and undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Royale, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. C. Ashley Smith, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ C. Ashley Smith
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Date Signed: February 1, 2016

Date Signed: February 1, 2016

CAS:AZH

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i.) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii.) Same environment of deposition;
(iii.) Similar geological structure; and
(iv.) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *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.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i.) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii.) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii.) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv.) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *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.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i.) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii.) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii.) Dry hole contributions and bottom hole contributions.
(iv.) Costs of drilling and equipping exploratory wells.
(v.) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *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 which 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.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): 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).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.
(ii) Undrilled locations can be classified as having 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for 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 been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.