SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K

[x] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: **December 31, 2011** OR

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 0-14731

"COAL KEEPS YOUR LIGHTS ON" "COAL KEEPS YOUR LIGHTS ON"

HALLADOR ENERGY COMPANY
(www.halladorenergy.com)

COLORADO (State of incorporation) | 84-1014610 (IRS Employer Identification No.)

1660 Lincoln Street, Suite 2700, Denver, Colorado (Address of principal executive offices) | 80264-2701 (Zip Code)

Issuer's telephone number: 303.839.5504

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

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $.01 par value

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities and Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

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

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

☐ Large accelerated filer ☐ Accelerated filer
☐ Non-accelerated filer (do not check if a small reporting company) ☑ Smaller reporting company

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

The aggregate market value of the common stock held by non-affiliates on June 30, 2011 was about $50 million based on the closing price reported that date by the NASDAQ of $9.59 per share.

As of February 29, 2012 we had 28,309,000 shares outstanding.

Portions of our information statement to be filed with the SEC in connection with our annual stockholders' meeting to be held on April 19, 2012 are incorporated by reference into Part III of this Form 10-K.

PART 1

ITEM 1. BUSINESS.

General Development of Business

In December 2009 we changed our name from Hallador Petroleum Company to Hallador Energy Company. We are a Colorado corporation and were organized by our predecessor in 1949. About 77% of our stock is held by officers, directors and their affiliates. Our stock is thinly traded (average daily volume is about 16,000 shares) on the NASDAQ Capital Market listing under the symbol HNRG.

The largest portion of our business is devoted to underground coal mining in the state of Indiana through Sunrise Coal LLC (a wholly-owned subsidiary) serving the electric power generation industry. We also own a 45% equity interest in Savoy Energy, L.P., a private oil and gas company with operations in Michigan. In late December 2010 we invested $2.4 million for a 50% interest in Sunrise Energy, LLC which then purchased existing gas reserves and gathering equipment from an unrelated third party with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for coal-bed methane gas reserves on or near our underground coal reserves. Development is pending an increase in nat-gas prices. The primary reason we consummated this purchase was to protect our coal reserves from unwanted fracking by unrelated parties. We account for our investments in Savoy and Sunrise Energy using the equity method. Through our Denver operations we also lease oil and gas mineral rights with the intent to sell the prospects to third parties and retain an overriding royalty interest (ORRI) or carried interest. Occasionally, we participate in the drilling of oil and gas wells. See Item 7- MD&A on page 18 for a discussion of Savoy, our successful lease play in North Dakota and our ORRIs in Wyoming.

Our largest contributor to revenue and earnings is the Carlisle underground coal mine located in western Indiana. The Carlisle mine was in the development stage through January 31, 2007. Coal shipments began February 5, 2007.

Active Reserve (assigned) - Carlisle

Our coal reserves at December 31, 2011 assigned to the Carlisle mine were 46 million tons compared to beginning of year reserves of 46.7 million tons. Primarily through the execution of new leases, our reserve additions of 2.6 million tons replaced about 80% of our 2011 production of about 3.3 million tons.

In addition to the Allerton reserve discussed below, we are currently evaluating multiple mining projects which could add to our coal reserves by the end of 2012. Some of these projects are near the Carlisle mine and if they come to fruition we expect to utilize our existing wash plant and load-out facility.

New Reserve (unassigned) - Allerton

We have leased roughly 19,500 acres in Vermillion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 32.3 million tons of recoverable coal reserves; 15.8 million which are proven and 16 million which are probable. A considerable amount of our 19,500 acres of leases has yet to receive any exploratory drilling, thus we anticipate our controlled reserves to grow as we continue drilling in 2012. The permitting process was started in the summer of 2011 and we anticipate filing the formal permit with the state of Illinois and the appropriate Federal regulators during the second quarter of 2012. If the process proceeds smoothly, we anticipate receiving a mining permit in the first half of 2013. Unassigned reserves represent coal reserves that would require new mineshafts, mining equipment and plant facilities before operations could begin on the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital expenditures before production can begin. Sunrise personnel have opened coal mines in this area in the past.

Full-scale mine development will not commence until there is proven market demand and we have a sales commitment.

Our Coal Contracts

Over the past three years we sold over 90% of our coal to three investment-grade customers. We have close relationships with these customers: Duke Energy Corporation (NYSE:DUK), Hoosier Energy, an electric cooperative, and Indianapolis Power & Light Company, a wholly-owned subsidiary of The AES Corporation (NYSE:AES). During 2011 we sold 300,000 tons of coal to Jacksonville Electric Authority (JEA). The addition of JEA is noteworthy as this is the first time we have sold coal to a customer as far as Jacksonville, Florida. We have no more contracts with JEA but are in discussion with other Florida utilities regarding such. We believe these discussions are the continuation of the trend of Illinois Basin (ILB) coal replacing Central Appalachia coal that traditionally supplied the southeast markets.

Only about 37% of our 2014 expected coal production is contracted for and we have no contracts extending past 2014. Of our 46 million tons of coal reserves assigned to the Carlisle mine, only 6.9 million tons are under contract; in other words about 85% of our reserves are uncommitted.

The table below illustrates the status of our current coal contracts:

Year	Contracted Tons	Average Price
2012	2,900,000	$42.35
2013 *	2,900,000	40.14
2014 *	1,100,000	46.34

*For 2013 and 2014 we have a contract for 900,000 tons each year with one of our customers and we have agreed to reopen the contracted price during 2013. Each side has agreed to negotiate in good faith; however, if we can't reach an agreed upon price, then our customer has the right to call the tons at the higher contracted price or if they don't call the tons then we have the right to put the tons to them at the lower contracted price. For purposes of the table we used the lowest price option considering the current state of the coal markets.

In the short-run, the market for thermal coal in the United States faces a number of challenges. Unusually mild winter weather has reduced electricity generation and thus both coal burn and gas burn, resulting in a rapid build in coal inventories that now stand at greater than 180 million tons nationwide, an increase of more than 30 million tons from just three months ago. The mild weather, burgeoning inventories and prolific production of natural gas has recently driven the price of natural gas to decade lows, which has increased fuel switching in favor of gas and forced the price of thermal coals lower across all production basins. Regulatory uncertainties, particularly surrounding the recently delayed Cross-state Air Pollution Rule (CSAPR), and Maximum Achievable Control Technology (MACT), are causing utilities to defer coal purchasing decisions, and in some cases to retire coal-fired generating facilities.

That being said, two of our customers have advised us that their coal stockpiles are increasing. We have orally agreed with one of the two customers to store 300,000 tons of coal on our property from the summer of 2012 to the summer of 2013. We will continue to sell the coal as contracted to this customer. The risks and rewards of ownership will pass from us to them. We will be paid an additional storage fee on the stored tons. We continue to work with the other customer and their inventory issues; a possible solution may also include storing their contracted tons. At this time we are unsure as to the ultimate outcome of these discussions.

If our future cash mining costs remain in our historical range of $24-25/ton over the next two years and if our expected maintenance capital expenditures (cap ex) each year are in the $10-12 million range, we expect to generate ample amounts of cash flow.

We have two sister wash plants engineered to work together with an annual capacity of 3.5-3.9 million clean tons at current recoveries. We have the capability of expanding underground production to meet this capacity. If prices are favorable we will expand underground production.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. Our approach is to selectively renew, blend and extend existing contracts, or enter into new, coal supply contracts when we can do so at prices we believe are favorable.

Typically, customers enter into coal supply agreements to secure reliable sources of coal at predictable prices while we seek stable sources of revenue to support the investments required to open, expand and maintain or improve productivity at the mines needed to supply these contracts. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers.

Quality and volumes for the coal are stipulated in coal supply agreements and in some limited instances buyers have the option to vary annual or monthly volumes if necessary. Variations to the quality and volumes of coal may lead to adjustments in the contract price. Our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content (British Thermal Units-Btus), moisture, sulfur and ash content.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, steel-related (including roof control) products, belting products, lubricants, electricity, fuel and tires. Although we have many long, well-established relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers other than for purchases of certain underground mining equipment and electricity. The supplier base providing mining materials has been relatively consistent in recent years, although there has been some consolidation. Purchases of certain underground mining equipment are concentrated with one principle supplier; however, supplier competition continues to develop.

Carlisle Mine

The Carlisle mine is located in the ILB and has about 46 million tons of high-sulfur bituminous coal reserves. Our historical coal specifications for this mine are: 13.15 % moisture; 11,483 Btu; 8.63% ash; 3.02% SO_2 and 5.27 lb SO_2. Compared to other ILB mines, our reserves have lower chlorine (<0.10%) than the average ILB of 0.22%. The relatively low chlorine content makes it highly attractive to buyers given their desire to limit the corrosive effects in their power plants.

The ILB boasts several long-term trends that are expected to benefit coal producers in the region. Historically, ILB coal demand has outpaced supply for several years. This supply/demand dynamic is driven by an increase in scrubber retrofits, new coal-fired capacity coming on line and coal depletion in the Eastern Basins. The local Indiana supply/demand market dynamics, coupled with new pockets of demand from nearby domestic markets, should provide a strong long-term demand foundation for our coal. Over 95% of the electricity generated in Indiana comes from coal-fired plants. Only West Virginia is higher. The majority of Indiana coal is consumed in Indiana.

Outside of the local market, demand for ILB coal has been on the rise and is expected to continue for the foreseeable future. ILB coal is well positioned to supply other domestic markets, as Eastern U.S. coal providers with depleting reserves continue to seek higher prices in international markets.

Transportation Advantage

The Carlisle mine has a double 100 rail car loop facility and a four-hour certified batch load out facility connected to the CSX railroad. The Indiana Rail Road (INRD) also has limited running rights on the CSX to our mine. Dual rail access gives us a freight advantage to our Indiana customers. Long term, the CSX anticipates our coal being shipped to southeast markets via their railroad.

We sell our coal FOB the mine. Substantially all of our coal is transported by rail. Our mine is accessible by truck and is within 90 miles of nine coal-fired plants that have been retrofitted to burn our high-sulfur coal.

Coal Preparation

Coal extracted from Carlisle contains impurities such as rock and sulfur. We utilize a wash plant located at the mine to remove impurities from the coal and to insure our product meets contract specifications. Our wash plant allows us to treat the coal we extract from Carlisle to ensure a consistent quality.

Illinois Basin (ILB)

The coal industry underwent a significant transformation in the early 1990s, as greater environmental accountability was established in the electric utility industry. Through the U.S. Clean Air Act, acceptable baseline levels were established for the release of sulfur dioxide in power plant emissions. In order to comply with the new law, most utilities switched fuel consumption to low-sulfur coal, thereby stripping the ILB of over 50 million tons of annual coal demand. This strategy continued until mid 2000 when a shortage of low-sulfur coal drove up prices. This price increase combined with the assurance from the U.S. government that the utility industry would be able to recoup their costs to install scrubbers caused utilities to begin investing in scrubbers on a large scale. With scrubbers, the ILB has reopened as a significant fuel source for utilities and has enabled them to burn lower cost, high sulfur coal.

The ILB consists of coal mining operations covering more than 50,000 square miles in Illinois, Indiana and western Kentucky. The ILB is centrally located between four of the largest regions that consume coal as fuel for electricity generation (East North Central, West South Central, West North Central and East South Central). These regions consumed about 63% of coal used in electric generation in 2008. The region also has access to sufficient rail and water transportation routes that service coal-fired power plants in these regions as well as other significant coal consuming regions of the South Atlantic and Middle Atlantic.

U. S. Coal Industry

The U.S. has over 200 billion tons of recoverable coal reserves, representing about 94% of the domestic fossil fuel energy, according to the U.S. Geological Survey (USGS). This is about 27% of the world's total proven reserves. The energy potential of American coal exceeds that of all the oil in the Middle East. The EIA (Energy Information Administration) estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for 200 years. The U.S. is also the second largest coal producer in the world, exceeded only by China. Annual coal production in the U.S. has increased from 434 million tons in 1960 to about 1 billion tons in 2010, based on information provided by the EIA. Coal is the fastest growing fuel in the world. The majority of coal consumed in the United States is used to generate electricity, with the balance used by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Metallurgical coal is predominately consumed in the production of metallurgical coke used in steelmaking blast furnaces. In 2010, coal-fired power plants produced approximately 45% of all electric power generation, more than natural gas and nuclear, the two next largest domestic fuel sources, combined. In 2010, 95% of US thermal coal consumption was by the electric power sector with the balance used in industrial and commercial applications.

According to the EIA, coal is expected to remain the largest energy source of electric power generation in the United States for the foreseeable future.

The major coal production basins in the U.S. include Central Appalachia (App), Northern App, Illinois Basin, Powder River Basin and the Western Bituminous region. The Central App Basin includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. The Northern App Basin includes Maryland, Ohio, Pennsylvania and northern West Virginia. The Illinois Basin includes Illinois, Indiana and western Kentucky. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. The Western Bituminous Basin includes western Colorado, eastern Utah and southern Wyoming.

Coal type varies by basin. Heat value and sulfur content are important quality characteristics and determine the end use for each coal type.

Coal in the U.S. is mined through surface and underground mining methods. According to the National Mining Association (NMA), of the coal produced during 2010, ⅔ came from surface mines and ⅓ from underground mines.

The primary underground mining techniques are longwall mining and continuous (room-and-pillar) mining. The geological conditions dictate which technique to use. The Carlisle mine uses the continuous technique.

In continuous mining, rooms are cut into the coal bed leaving a series of pillars, or columns of coal, to help support the mine roof and control the flow of air. Continuous mining equipment cuts the coal from the mining face. Generally, openings are driven 20' wide and the pillars are rectangular in shape measuring 40'x 40'. As mining advances, a grid-like pattern of entries and pillars is formed. Roof bolts are used to secure the roof of the mine. Battery cars move the coal to the conveyor belt for transport to the surface. The pillars can constitute up to 50% of the total coal in a seam.

Competitive Pressures

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. We compete against large producers and hundreds of small producers in the United States. The five largest producers are estimated by the 2009 NMA Survey to have produced approximately 53% (based on tonnage produced) of the total United States production in 2009. The U.S. Department of Energy reported about 1,300 active coal mines in the United States in 2010, the latest year for which government statistics are available. Peabody Energy Corporation (NYSE:BTU) and Foresight Energy, a private company controlled by Chris Cline are probably the two largest operators in the ILB. While we sold about three million tons from our Carlisle mine, Peabody sold about 28 million tons from 12 mines (surface and underground) in the ILB during 2011. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power or wind;
- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of fuel supply.

Continued demand for our coal and the prices that we receive are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing coal and alternative fuel supplies.

Coal is the primary fuel source (about 45%) for electrical generation in the U.S. Despite capacity growth for other fuel sources of electricity, coal is still expected to provide the largest share of energy for U.S. electricity generation.

Natural Gas

One of the trends that cause us concern is the burning of natural gas to generate electricity in the U.S. Affordability plays a significant role in coal's position as the most used fuel source in energy generation. In the U.S., coal has historically had a relatively lower delivered cost per million Btu (MMBtu) compared to other energy sources. The EIA projects coal prices to be $2.40 on a dollars per MMbtu basis.

Although coal has been and remains the major fuel for electricity generation in the U.S., natural gas has increased its share as a fuel in electrical generation in recent years. High natural gas prices in 2003 and 2004 made it economical for power generators to retrofit existing coal-burning units with scrubbers and low nitrogen oxide burner technology or switch to lower-sulfur coals in order to reduce emissions. Recently, however, natural gas substitution in electricity generation has increased. Natural gas spot prices declined sharply from about $13 per MMBtu in the summer of 2008 to current prices in the $2.50 per MMBtu range prompting some utilities to substitute natural gas for coal as fuel in electricity generation.

Gas producers have been arguing for some time that new sources of fuel, especially shale gas, have made it both plentiful and reliable. Furthermore, carbon dioxide emission from burning natural gas compared to coal is about 50% less. But residential and industrial consumers, from homeowners to power utilities, have been reluctant to increase their dependence on natural gas because of concerns about price volatility. This appears to be changing, due to a combination of factors. Huge new discoveries in the U.S. and Canada have greatly increased supplies, lowering prices. Big infrastructure build-outs in recent years have made it easier to move gas around to where it is needed, helping ease regional price spikes. Recent multi-billion deals by large domestic and foreign entities are the latest signs that these entities see U.S. natural gas, especially gas found in shale rock, as a giant resource. Gas producers hope these deals will help them convince federal officials and power executives that prices are entering a period of relative calm.

There are some that believe natural gas will overtake coal as the most economic way to produce electricity in the U.S. In the event the government places a price tag on carbon emissions, natural gas would gain another advantage over coal since electricity from coal produces more carbon. Some natural gas producers believe that there is certainly the potential for natural gas producers and utilities to develop a new relationship that has not been possible historically.

Employees

Our coal operations currently employ 333 people. We use a consulting geologist when evaluating new coal mine projects. We also use a consultant to sell our coal, find new buyers and help in contract negotiations. The mine currently operates two production shifts and one maintenance shift while coal is produced 270 days of the year. The Carlisle mine is non-union.

Safety and Environmental Regulations

Our operations, like operations of other coal companies, are subject to extensive regulation, primarily by federal and state authorities, on matters such as: air quality standards; reclamation and restoration activities involving our mining properties; mine permits and other licensing requirements; water pollution; employee health and safety; management of materials generated by mining operations; storage of petroleum products; protection of wetlands and endangered plant and wildlife protection. Many of these regulations require registration, permitting, compliance, monitoring and self-reporting and may impose civil and criminal penalties for non-compliance.

Additionally, the electric generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal over time. The possibility exists that new legislation or regulations may be adopted or that the enforcement of existing laws could become more stringent, causing coal to become a less attractive fuel source and reducing the percentage of electricity generated from coal. Future legislation or regulation or more stringent enforcement of existing laws may have a significant impact on our mining operations or our customers' ability to use coal.

While it is not possible to accurately quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds or post letters of credit from our banks to guarantee performance or payment of certain long-term obligations, including mine closure and reclamation costs.

We don't think it is necessary to discuss all the different laws and regulations that we are subject to. Suffice it to say, the coal industry in under attack by the current administration. If there is a change in administration resulting from the November 2012 elections that will be positive for the coal industry, if not, that would be negative.

Reclamation

The Carlisle mine began commercial production in February 2007 and is operating in compliance with all local, state, and federal regulations. We have no old mine properties to reclaim, other than the Howesville mine, which was operated for only eight months before it was closed in June 2006 due to safety concerns. During 2007, we finished Phase I of the reclamation of the Howesville mine. To reach final reclamation we must raise commercial crops for a period of five years.

Currently we do not operate any surface mines.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. The authorization, permitting and implementation requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. Regulations also provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a shareholder with a 10% or greater interest in the entity is affiliated with another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, we submit the necessary permit applications several months before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain, and the application review processes are taking longer to complete and becoming increasingly subject to challenge.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. Compliance with these laws has increased the cost of coal mining for domestic coal producers.

Mine Health and Safety Laws

We are proud of our safety record. We comply with the rules and regulation issued by the Mine Safety and Health Administration (MSHA) and also state rules and regulations. We applaud all reasonable rules and regulation that promote mine safety and keep our miners out of harm’s way. Complying with these existing rules and proposed rules add to our mining costs.

Clean Air Act and Related Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, primarily through permitting and/or emissions control requirements.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal-fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas (GHG), is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales. For example, the federal Clean Air Act places limits on sulfur dioxide, nitrogen dioxide, and mercury emissions from electric power plants.

The installation of additional control measures to achieve regulatory emission reductions makes it more costly to operate coal-fired power plants and could make coal a less attractive fuel. In order to meet the proposed new limits for sulfur dioxide emissions from electric power plants, many coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. More strict emission limits mean few coals can be burned without the installation of supplemental environmental control technology in the form of scrubbers.

These types of regulations and requirements and proposed such regulations and requirements could significantly increase our customers' costs and cause them to reduce their demand for coal, which may materially impact our results of operations.

Other

We have no significant patents, trademarks, licenses, franchises or concessions.

Other than the 333 Sunrise Coal employees in Indiana, our CEO, CFO, controller, geologist, land person and two part time administrative staff work in the Denver office.

Our Denver office is located at 1660 Lincoln Street, Suite 2700, Denver, Colorado 80264, phone 303.839.5504 and Sunrise Coal's corporate office is located at 1183 Canvasback Drive, Terre Haute, Indiana 47802, phone 812.299.2800. Terre Haute is approximately 70 miles west of Indianapolis. Our website is www.halladorenergy.com and Sunrise Coal's is www.sunrisecoal.com .

ITEM 1A. RISK FACTORS.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Smaller reporting companies are not required to provide the information required by this item; however, there were none.

ITEM 2. PROPERTIES.

The Carlisle mine, located near the town of Carlisle in Sullivan County, Indiana, is an underground mine which became operational in January 2007. The coal is accessed with a slope to a depth of 340'. The coal is mined in the Indiana Coal V seam which is highly volatile bituminous coal.

Our current mine plan indicates 15,100 acres of mineable coal with an approximate 4' to 7' thickness in the project area. Of the 15,100 acres, 13,600 are currently under lease to Sunrise. The Indiana V seam has been extensively mined by underground and surface methods in the general area and is the most economically significant coal in Indiana.

Findings are based on generally accepted engineering principles and professional experience in the mining industry. All judgments are based on the facts that are available at this time.

Assigned Coal Reserve Estimates- Carlisle Mine

We estimate that, as of December 31, 2011, the Carlisle Mine had total recoverable reserves of approximately 46 million tons consisting of both proven (36 million) and probable (10 million) reserves. “Reserves” are defined by the SEC Industry Guide 7 (Guide 7) as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. “Recoverable” reserves mean coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. “Proven (measured) reserves” are defined by Guide 7 as reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. “Probable reserves” are defined by Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Unassigned New Coal Reserves – Allerton

See page three for a discussion of Allerton.

Our reserve estimates were prepared by Samuel Elder and Jacob Gennicks, two of our mining engineers. Mr. Elder is a licensed Professional Engineer in the State of Indiana and has over 25 years experience estimating coal reserves. Mr. Gennicks is a licensed Professional Engineer in the State of Indiana and Illinois and has three years experience estimating coal reserves.

The reserve estimates for all leased acres was made utilizing Carlson Mining 2009 (software developed by Carlson Software). To convert volumes of coal to an in-place tonnage, a weight of 80 pounds/cubic foot was used for both reserve areas. To convert Carlisle reserve to product tonnage, a 53% mine recovery and an average of 79% washed recovery (coal only recovery, no out-of- seam dilution included) were used.

Example: In-place tonnage x 53% x 79% = product tonnage.

To convert Allerton reserve to product tonnage, a 45% mine recovery and an average of 77% washed recovery (coal only recovery, no out-of- seam dilution included) were used.

Example: In-place tonnage x 45% x 77% = product tonnage.

Standards set forth by the USGS were used to place areas of the mine reserves into the Proven (measured) and Probable (indicated) categories. Under these standards, coal within 1,320' of a data point is considered to be proven, and coal within 1,320' to 3,960' is placed in the Probable category. All reserves are stated as a final salable product.

ADDITIONAL DISCLOSURES FOR THE CARLISLE MINE

1. The Carlisle mine currently has road frontage on State Highway 58, and is adjacent to the CSX railroad. The Carlisle mine has a double 100 car loop facility. Substantially all of our coal is shipped by rail.

2. Currently only the Indiana V seam is planned to be mined, and all of the controlled tonnage is leased to Sunrise. Most leases have unlimited terms once mining has begun, and yearly payments or earned royalties are kept current. Mineable coal thickness used is greater than four feet. The current Carlisle mine plan is broken into four areas– North Main – South Main – West Main – 2 South Main. Approximately 84% of the total mine plan is currently under lease ("controlled"). It is believed that all additional property that would be required to access all lease areas can be obtained but, if some properties cannot be leased, some modification of the current mine plan would be required. All coal should be mined within the terms of the leases. Leasing programs are continuing by our staff.

3. The Carlisle mine has a dual-use slope for the main coal conveyor and the moving of supplies and personnel. There are two 8' diameter shafts at the base of the slope for mine ventilation. Two additional air shafts (8’ and 10.5’ diameter) were completed about three miles north of the original air shaft in 2009 to facilitate the mine expansion. The slope (9° or 15% grade) is 18' wide with concrete and steel arch construction. A 16’ hoist is now open (spring 2011) approximately four miles north of the main slope. The hoist is currently facilitating two production units by efficiently moving personnel and materials into the north main and north main addition areas of the reserve. All underground mining equipment is powered with electricity and underground compliant diesel.

4. The new slurry impoundment continues to be under construction, due in part to design modifications, but is currently approved for, and being utilized for slurry disposal. When final construction is completed in 2012 the structure will handle disposal for roughly 36 million clean tons of coal.

5. Current production capabilities are projected to be in the range of 3 to 3.3 million tons per year giving the mine a reserve life of about 15 years. The mine plan is basic room-and-pillar using a synchronized continuous miner section with no retreat mining. Plans are for pillars to be centered on a 60'x80' pattern with 18' entries for our mains, and pillars on 60'x60' centers with 20' entries in the rooms.

6. The Carlisle mine has been in production since February 2007. The North Main, Sub Main #1, and the South Main have been developed with four units currently in production.

7. The Carlisle mine has two wash plants capable of 950 tons/hour of raw feed.

Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal engineers. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;

- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates.

ITEM 3. LEGAL PROCEEDINGS . None

ITEM 4. MINE SAFETY DISCLOSURES

See Exhibit 95 to this Form 10-K for a listing of our mine safety violations.

PART II

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

Our common stock is traded on the NASDAQ Capital Market under the symbol HNRG. Prior to May 27, 2010 we were traded on the OTC Bulletin Board under the symbol HPCO.OB. The following table sets forth the high and low closing sales price for the periods indicated:

	High	Low
2012		
(January 1 through February 29, 2012)	$ 10.45	$ 9.54
2011		
Fourth quarter	10.47	8.55
Third quarter	10.22	8.25
Second quarter	12.05	9.42
First quarter	11.43	9.79
2010		
Fourth quarter	12.64	10.47
Third quarter	12.10	7.36
Second quarter	13.00	8.25
First quarter	9.80	7.50

During May 2010 we declared our first cash dividend of $0.10 per common share of which there were 27,782,028 outstanding. Furthermore, our board approved that the dividend would also apply to the 1,150,000 outstanding restricted stock units (RSUs) and to the 434,167 outstanding stock options on that date. The total cash payment for all the outstanding securities was about $2.9 million. During May 2011 we declared another special dividend of $0.12 per share. As was done last year, the dividend also applied to our outstanding RSUs and stock options. The total cash payment for all the outstanding securities was about $3.5 million. We evaluated our cash position and capital requirements and decided to declare another special cash dividend of $.14 per share payable in April 2012. The total payment, which also covers our outstanding RSUs and options, will be about $4.1million.

At February 29, 2012, we had 251 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 300 street name holders. On February 29, 2012 our stock closed at $10.10.

Equity Compensation Plan Information

On January 7, 2011 we allowed four Denver employees (non officers) an opportunity to relinquish 100% of their vested options (234,167) for 181,261 shares of our common stock. The exchange ratio was based on the intrinsic value of their options. These shares were issued under our Stock Bonus Plan which was created in December 2009. Under such plan employees are allowed to relinquish shares to pay for their income taxes; accordingly, 41,645 shares were relinquished.

Currently we have 200,000 outstanding stock options to our CEO with an exercise price of $2.30. The options are fully vested and expire in April 2015.

At December 31, 2011 we had 636,000 RSUs outstanding and about 922,000 available for future issuance. Our RSU and stock option plans were approved by our BODs and collectively they and their affiliates control about 77% of our stock.

ITEM 6. SELECTED FINANCIAL DATA.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Overview

The largest portion of our business is devoted to underground coal mining in the state of Indiana through Sunrise Coal LLC (a wholly-owned subsidiary) serving the electric power generation industry. We also own a 45% equity interest in Savoy Energy, L.P., a private oil and gas company with operations in Michigan. In late December 2010 we invested $2.4 million for a 50% interest in Sunrise Energy, LLC which then purchased existing gas reserves and gathering equipment from an unrelated third party with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for coal-bed methane gas reserves on or near our underground coal reserves. Development is pending an increase in nat-gas prices. The primary reason we consummated this purchase was to protect our coal reserves from unwanted fracking by unrelated third parties. We account for our investments in Savoy and Sunrise Energy using the equity method. Through our Denver operations we also lease oil and gas mineral rights with the intent to sell the prospects to third parties and retain an overriding royalty interest (ORRI) or carried interest. Occasionally, we participate in the drilling of oil and gas wells. Further below are discussions of Savoy, our successful lease play in North Dakota and our ORRIs in Wyoming.

Our largest contributor to revenue and earnings is the Carlisle underground coal mine located in western Indiana, about thirty miles south of Terre Haute. The Carlisle mine was in the development stage through January 31, 2007. Coal shipments began February 5, 2007.

Outlook

Headwinds created by low natural gas prices, mild weather, and weaker domestic economies impacted coal markets during the year, and market weakness continues as we enter 2012.

The current exceptionally mild winter has dramatically decreased demand for electricity: since October 2011, heating degree days are down by 17 percent compared to normal, and electricity demand is estimated to be down by 3.3 percent. This lack of demand is a major factor behind the current low near-term gas and coal prices. Unless there is a dramatic cold snap, these conditions are expected to persist until the summer. For 2012 we will continue to focus on maintaining our low cost structure and leasing and permitting new reserves.

We do see an increasing demand for coal produced in the ILB in the future. Demand for coal produced in the ILB is expected to grow at a rate faster than overall U.S. coal demand, due to ILB coal having higher heating content than PRB and lower cost structure than Central App coal. Many utilities are scrubbing to meet emission requirements beyond just sulfur compliance, even utilities that burn exclusively PRB. Once scrubbed, those utilities are usually capable of burning ILB coal. It is this trend of new scrubber installations coupled with rising Central App cost structure that is leading to increased switching from Central App coal to ILB coal. Some fuel switching will also occur from PRB to ILB in newly scrubbed utilities located near ILB coal supply.

Growth in international coal import demand has resulted primarily from increased demand for thermal coal for electricity generation by emerging global economies, particularly by Asian countries in the Pacific market where coal is the primary fuel source for new power generation. We believe that the widening of the Panama Canal in 2014 should lower freight rates which would enhance coal exports to Asia.

In Europe, domestic coal supply has declined due to reduction in domestic production as a result of the region’s declining coal reserve base and a reduction in government subsidies for coal mining, particularly in Poland, Germany and Spain. Additionally, the International Atomic Energy Agency projects slower global growth in nuclear power capacity following the 2011 earthquake in Japan and related nuclear incident. Germany, in particular, has closed certain older facilities and is planning to shut down its remaining nuclear plants by 2022. Coal-fired generation is expected to meet a large portion of this additional demand. We believe that the decline in domestic production in Europe, coupled with an expected increase in coal-fired power generation, will result in an increase in thermal coal imports.

Due to the location of our coal mine, we expect to continue concentrating our efforts on supplying the domestic market. We expect as more coal is exported from the ILB, the coal that remains for the domestic market will increase in value.

As discussed further under "Competitive Pressures" on page nine, natural gas has increased its share as a fuel in electrical generation in recent years.

Yorktown Distribution

As previously disclosed, each time after we filed our 2011 Form 10-Qs for the first three quarters, we were advised by Yorktown Energy Partners VI, L.P., an investor for the last sixyears, that it had distributed shares of our common stock to its limited and general partners. First and second quarter distributions were 750,000 shares each and the third quarter distribution was 556,000 shares for a total of 2,056,000 shares. After the three distributions, Yorktown and its affiliates collectively hold about 13 million shares of our common stock representing about 46% of total shares outstanding.

While we do not know Yorktown's ultimate strategy to realize the value of their Hallador investment for their partners, we expect that over time distributions such as these will improve our liquidity and float. If and when we are advised of another Yorktown distribution after this Form 10-K is filed, we will timely report such on a Form 8-K.

Our consolidated financial statements should be read in conjunction with this discussion.

Prospective Information

See page four of this report for a table that illustrates the status of our current coal contracts.

Liquidity and Capital Resources

For 2011 we generated $61 million in cash from operations which enabled us to reduce our bank debt by $10 million, invest $24 million in the Carlisle mine, buy land for about $9 million for the Allerton project and pay a special dividend of $3.5 million . For 2012 we are scheduled to extinguish our bank debt in December and we anticipate our capital expenditures for the Carlisle mine falling to $10-12 million. We expect next year's cash from operations to be lower due to the non-recurring gain of $10.7 million. Future cash flow from operations could be negatively impacted depending on the final outcome of our contract negotiations as discussed on page four of this report. Our cash flow from operations will also be negatively impacted by payments of state and federal income taxes.

We do not anticipate any liquidity issues in the foreseeable future. Eventually, when we develop a new reserve, we intend to incur additional debt and restructure our existing credit facility.

We have no material off-balance sheet arrangements.

During May 2010 we declared our first cash dividend of $0.10 per common share of which there were 27,782,028 outstanding. Furthermore, our board approved that the dividend would also apply to the 1,150,000 outstanding RSUs and to the 434,167 outstanding stock options on that date. The total cash payment for all the outstanding securities was about $2.9 million. During May 2011 we declared another special dividend of $0.12 per share. As was done last year, the dividend also applied to our outstanding RSUs and stock options. The total cash payment for all the outstanding securities was about $3.5 million. We evaluated our cash position and capital requirements and decided to declare another special cash dividend of $.14 per share payable in April 2012. The total payment, which also covers our outstanding RSUs and options, will be about $4.1million.

In late August 2010 we decided to drop the property insurance on our underground mining equipment. We feel comfortable with this decision as such equipment is allocated among four mining units spread out over eight miles. The historical cost of such equipment is about $93 million.

Project Update

New Reserve (unassigned) – Allerton

See page three of this report for a discussion of our Allerton project .

MSHA Reimbursements

Two of our major contracts allow us to pass on certain costs incurred resulting from changes in costs to comply with mandates issued by MSHA or other government agencies. In late December 2010, we submitted a report which was reviewed by an outside consulting firm engaged by our customers. In January 2011 the two customers agreed to reimburse us about $1.9 million for costs incurred by us during 2008 and 2009. During those years we were not able to accurately estimate what the ultimate outcome of these reimbursable costs would be so we did not record them until we were certain of the amounts and certain of collection. Such amounts were recorded during the first quarter of 2011.

We submitted our incurred costs for 2010 in September of 2011 for $4 million. One of the customers paid $2 million in February 2012 and we continue discussions with the other customer. Accounting recognition for these 2010 reimbursements will be made in 2012.

Oil and Gas Properties

ORRI

We have an ORRI of about 2% on 22,500 acres and a 4% ORRI on 2,500 acres in Laramie County, Wyoming. This ORRI was obtained from leases we sold to SM Energy Company (formerly St. Mary Land) (NYSE:SM) in October 2008. This is a Niobrara oil shale play in the northern D-J Basin. During 2010, SM Energy drilled a discovery well (the Atlas 1-19) on this acreage. Through 2011 this well has produced 121,000 barrels of oil. During 2011 three additional wells were drilled and completed on our acreage with mixed results. It is uncertain how many more wills be drilled by SM. For 2011 we received $114,000 from these ORRI's.

North Dakota Lease Play (Patriots Prospect)

We invested about $2.5 million in a lease play located in Slope, Hettinger and Stark counties of North Dakota which resulted in the purchase of about 10,600 net acres of oil and gas leases. On June 10, 2011, we signed a letter of intent with Chesapeake Energy Corporation (NYSE:CHK) to sell such acreage and on July 29, 2011, the deal closed. CHK purchased a 90% working interest for $13.2 million resulting in a pre-tax gain of about $10.6 million considering selling expenses and non-executive employee bonuses; due to some post-closing curative work about $1.5 million of the gain was recognized during the fourth quarter. We retained a 10% working interest and an approximate 3% average ORRI. If and when a well is proposed, we expect to participate in the drilling .

Results of Operations

For 2011, we sold 3,307,000 tons at an average price of $41.71/ton. For 2010 we sold 3,050,000 tons at an average price of $42.31/ton. Our average price for 2012, based on our contracts, is expected to be about $42.35/ton.

The 2011 "other income" is due to the MSHA reimbursements discussed above. The 2010 "other loss" of $772,000 was attributable primarily to our participating in the drilling of a dry hole in Michigan on a gas prospect developed by Savoy. Our share of the dry hole was about $1 million.

Operating costs and expenses averaged $23.31/ton in 2011 compared to $23.69 in 2010. We expect such costs to average $24-25/ton for 2012.

The increase in DD&A was due to additions to plant and equipment.

SG&A increased primarily due to higher expenses related to the new Allerton reserve, increases in certain salaries and increases in attending industry and investor conferences. Also we incurred higher curative costs to perfect our coal leases.

Our effective tax rate for 2011 and 2010 was in the 37-39% range and we expect such rate to be in the 32-36% range for 2012.

45% Ownership in Savoy

Savoy operates almost exclusively in Michigan. They have an interest in the Trenton-Black River Play in Southern Michigan. They hold 200,000 gross acres (about 100,000 net) in Hillsdale and Lenawee counties. During 2011 Savoy drilled 17 gross wells in this play of which 8 were dry and 9 were successful. During 2012 Savoy plans on drilling 25 additional wells in the play. Drilling locations in this play are identified based on the evaluation of extensive 3-D seismic shoots. Savoy operates their own wells and their working interest averages between 40 and 50% and their net revenue interest averages between 34 and 42%. Savoy's net daily oil production currently averages about 805 barrels of oil and 340 (Mcf) of gas. Savoy has an interest in about 63 wells (25 net). LOE was about $8 per barrel of oil.

Savoy's proved reserves are stated below and also in Note 5 to the financial statements. The pre-tax (Savoy is a partnership) present value of their future cash flows discounted at 10% (PV10) was about $97 million. Investors should note that the above numbers are to the 100%; our ownership in Savoy is about 45% so our share of the PV10 using SEC prices would be about $44 million.

The 2011 reserve report was prepared by Netherland, Sewell & Associates, Inc. (NSAI). See Note 5 for the qualifications of NSAI. The 2010 reserve report was prepared by Timothy Lovseth, our full-time geologist who has 30 years of experience in the oil and gas industry. Mr. Lovseth has no ownership in Savoy.

The table below illustrates the growth in Savoy over the last two years; such unaudited amounts are to the 100%, in other words not shown proportionate to our 45% interest (financial statement data in thousands):

	2011	2010
Revenue:		
Oil	$ 25,781	$ 11,138
Gas	566	760
NGLs (natural gas liquids)	868	227
Contract drilling	4,336	1,735
Gain on sale of unproved properties		2,225
Other	446	587
Total revenue	31,997	16,672
Costs and expenses:		
LOE (lease operating expenses)	2,257	1,725
Severance tax	2,037	818
Contract drilling costs	2,559	1,445
DD&A (depreciation, depletion & amortization)	4,733	3,147
Geological and geophysical costs	1,973	2,632
Dry hole costs	1,852	808
Impairment of unproved properties	2,963	2,543
Other exploration costs	357	204
G&A (general & administrative)	1,166	1,116
Total expenses	19,897	14,438
Net income	$ 12,100	$ 2,234
The information below is not in thousands:		
Oil production in barrels	283,000	149,000
4th quarter oil production in barrels	76,600	57,000
Gas production in Mcf	134,500	173,000
Average oil prices/barrel	$ 91	$ 75
Average gas prices/Mcf	$ 4.20	$ 4.38
Oil reserves (Bbls)	1,921,000	774,000
Gas reserves (Mcf)	2,491,000	787,000
PV 10 using SEC dictated average oil prices of $93.60 and $74	$97 million	$34 million

Critical Accounting Estimates and Significant Accounting Policies

We believe that the estimates of our coal reserves and our deferred tax assets and liability accounts are our only critical accounting estimates. Since the Carlisle mine has only been in production since February 2007 we do not have a long history to rely on. The reserve estimates are used in the DD&A calculation, in our impairment test and in our internal cash flow projections. If these estimates turn out to be materially under or over-stated; our DD&A expense and impairment test may be affected. Furthermore, if our coal reserves are materially overstated our liquidity and stock price could be adversely affected.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. None of our corporate tax returns have been examined in the last ten years. We were recently advised by the IRS that they will perform an examination of our 2009 and 2010 tax returns; such exam is to commence in mid-March 2012. We were also notified by Indiana tax representatives that they will examine our 2008-2010 tax returns; such exam is to commence this summer. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. Therefore, no reserves for uncertain income tax positions have been recorded.

Our significant accounting policies are set forth in Note 1 to the Financial Statements.

New Accounting Pronouncements

None of the recent FASB pronouncements will have any material effect on us.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Smaller reporting companies are not required to provide supplementary data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Hallador Energy Company
Denver, Colorado

We have audited the accompanying consolidated balance sheet of Hallador Energy Company and Subsidiaries (the "Company") as of December 31, 2010 and 2011, and the related consolidated statements of operations, cash flows, and stockholders' equity for each of the years in the two year period ended December 31, 2011. 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 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 audit 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hallador Energy Company and Subsidiaries, as of December 31, 2010 and 2011, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

Ehrhardt Keefe Steiner & Hottman PC

March 2, 2012
Denver, Colorado

Consolidated Balance Sheet
As of December 31,
(in thousands, except per share data)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 37,542	$ 10,277
Certificates of deposit		1,291
Prepaid Federal income taxes		3,853
Accounts receivable	6,689	5,450
Coal inventory	1,863	2,100
Parts and supply inventory	2,202	2,411
Other	580	850
Total current assets	48,876	26,232
Coal properties, at cost:		
Land, buildings and equipment	137,707	114,476
Mine development	66,614	59,351
	204,321	173,827
Less - accumulated DD&A	(42,493)	(28,435)
	161,828	145,392
Investment in Savoy	12,133	7,717
Investment in Sunrise Energy	3,297	2,375
Other assets (Note 8)	6,294	4,948
	$ 232,428	$ 186,664
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt	$ 17,500	10,000
Accounts payable and accrued liabilities	10,411	8,809
Income taxes	5,125	
Other	60	692
Total current liabilities	33,096	19,501
Long-term liabilities:		
Bank debt, net of current portion		17,500
Deferred income taxes	31,100	17,435
Asset retirement obligations	2,276	1,150
Other	4,963	4,345
Total long-term liabilities	38,339	40,430
Total liabilities	71,435	59,931
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.10 par value, 10,000 shares authorized; none issued		
Common stock, $.01 par value, 100,000 shares authorized; 28,309 and 27,924 outstanding, respectively	283	279
Additional paid-in capital	85,984	84,073
Retained earnings	74,685	42,381
Accumulated other comprehensive income	41	
Total stockholders' equity	160,993	126,733
	$ 232,428	$ 186,664

See accompanying notes .

Consolidated Statement of Operations
For the years ended December 31,
(in thousands, except per share data)

	2011	2010
Revenue:		
Coal sales	$ 137,998	$ 129,003
Gain on sale of unproved oil and gas properties	10,653	
Equity income - Savoy	5,476	1,005
Equity income - Sunrise Energy	922	
Other income (loss) (Note 8)	2,305	(772)
	157,354	129,236
Costs and expenses:		
Operating costs and expenses	77,094	72,527
DD&A	14,096	11,818
Coal exploration costs	1,132	780
SG&A	7,004	5,556
Interest	1,288	1,926
	100,614	92,607
Income before income taxes	56,740	36,629
Less income taxes:		
Current	7,266	885
Deferred	13,665	13,369
	20,931	14,254
Net income	$ 35,809	$ 22,375
Net income per share:		
Basic	$ 1.27	$ .81
Diluted	$ 1.25	$ .78
Weighted average shares outstanding:		
Basic	28,135	27,790
Diluted	28,694	28,571

See accompanying notes.

Consolidated Statement of Cash Flows

For the years ended December 31,
(in thousands)

	2011	2010
Operating activities:		
Net income	$ 35,809	$ 22,375
Gain on sale	(10,653)	
Deferred income taxes	13,665	13,369
Equity income – Savoy and Sunrise Energy	(6,398)	(1,005)
Cash distributions from Savoy	1,060	
DD&A	14,096	11,818
Change in fair value of interest rate swaps	(632)	(712)
Stock-based compensation	2,331	2,194
Other	576	
Taxes paid on vesting of RSUs	(1,661)	(746)
Change in current assets and liabilities:		
Accounts receivable	221	(163)
Coal inventory	236	66
Income tax accounts	8,978	(2,807)
Accounts payable and accrued liabilities	1,751	1,415
Other	1,341	(259)
Cash provided by operating activities	60,720	45,545
Investing activities:		
Proceeds from sale of unproved oil and gas properties	13,195	
Capital expenditures for coal properties	(32,995)	(34,714)
Capital expenditures for unproved oil and gas properties	(1,710)	(915)
Investment in Sunrise Energy		(2,375)
Investment in Savoy		(453)
Change in CDs	1,291	2,167
Marketable securities	(2,257)	
Other	1,284	(752)
Cash used in investing activities	(21,192)	(37,042)
Financing activities:		
Payments of bank debt	(10,000)	(10,000)
Dividends	(3,505)	(2,937)
Stock option buy-out		(679)
Tax benefit from stock-based compensation	1,242	327
Other		(163)
Cash used in financing activities	(12,263)	(13,452)
Increase (decrease) in cash and cash equivalents	27,265	(4,949)
Cash and cash equivalents, beginning of year	10,277	15,226
Cash and cash equivalents, end of year	$ 37,542	$ 10,277
Cash paid for interest	$ 1,508	$ 2,255
Cash paid for income taxes	$ 100	$ 4,400
Changes in accounts payable for coal properties	$ (358)	$ (2,088)

See accompanying notes.

Consolidated Statement of Stockholders' Equity
(in thousands)

	Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	AOCI*	Total
Balance January 1, 2010	27,782	$ 277	$ 85,245	$ 23,105		$ 108,627
Stock issued to board member for director services	9	1	99			100
Stock-based compensation			2,194			2,194
Stock issued on vesting of RSUs	133	1				1
Taxes paid on vesting of RSUs			(746)			(746)
Tax benefit from stock-based compensation			327			327
Stock option buy out for cash			(679)			(679)
Reduction in deferred tax asset resulting from Sunrise acquisition			(2,367)			(2,367)
Cash distributions to former noncontrolling interests for personal income taxes				(162)		(162)
Dividends				(2,937)		(2,937)
Net income				22,375		22,375
Balance December 31, 2010	27,924	$ 279	$ 84,073	$ 42,381		$ 126,733
Stock issued to board member for director services	11		100			100
Stock-based compensation			2,231			2,231
Exercise of employee stock options for shares	181	1	(1)			
Taxes paid for shares issued to employees	(41)		(469)			(469)
Stock issued on vesting of RSUs	345	3				3
Taxes paid on vesting of RSUs	(111)		(1,192)			(1,192)
Tax benefit from stock-based compensation			1,242			1,242
Increase in value of marketable securities available for sale, net of taxes					$ 41	41
Dividends				(3,505)		(3,505)
Net income				35,809		35,809
Balance December 31, 2011	28,309	$ 283	$ 85,984	$ 74,685	$ 41	$ 160,993

See accompanying notes.

Net income	$35,809
OCI	41
Comprehensive income	$35,850

*Accumulated Other Comprehensive Income

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

The consolidated financial statements include the accounts of Hallador Energy Company (the "Company") and its wholly-owned subsidiary Sunrise Coal, LLC (Sunrise). All significant intercompany accounts and transactions have been eliminated. We are engaged in the production of steam coal from an underground mine located in western Indiana. We own a 45% equity interest in Savoy Energy L.P., a private oil and gas company which has operations in Michigan and a 50% interest in Sunrise Energy LLC, a private entity engaged in natural gas operations in the same vicinity as our coal mine. We purchased our interest in Sunrise Energy in December 2010.

Reclassification

To maintain consistency and comparability, certain amounts in the 2010 financial statements have been reclassified to conform to current year presentation.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs and overhead.

Advance Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced.

Coal Properties

Coal properties are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Expenditures that extend the useful lives or increase the productivity of the assets are capitalized. The cost of maintenance and repairs that do not extend the useful lives or increase the productivity of the assets are expensed as incurred. Other than land and underground mining equipment, coal properties are depreciated using the units-of-production method over the estimated recoverable reserves. Surface and underground mining equipment is depreciated using estimated useful lives ranging from five to twenty years.

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed for recoverability. If this review indicates that the carrying value of the asset will not be recoverable through estimated undiscounted future net cash flows related to the asset over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its estimated fair value.

Mine Development

Costs of developing new coal mines, including asset retirement obligation assets, or significantly expanding the capacity of existing mines, are capitalized and amortized using the units-of-production method over estimated recoverable (proved and probable) reserves.

Asset Retirement Obligations (ARO) - Reclamation

At the time they are incurred, legal obligations associated with the retirement of long-lived assets are reflected at their estimated fair value, with a corresponding charge to mine development. Obligations are typically incurred when we commence development of underground mines, and include reclamation of support facilities, refuse areas and slurry ponds.

Obligations are reflected at the present value of their future cash flows. We reflect accretion of the obligations for the period from the date they are incurred through the date they are extinguished. The asset retirement obligation assets are amortized using the units-of-production method over estimated recoverable (proved and probable) reserves. We are using a 6% discount rate.

Federal and state laws require that mines be reclaimed to their previous condition in accordance with specific standards and approved reclamation plans, as outlined in mining permits. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, and reclamation of refuse areas and slurry ponds.

We assess our ARO at least annually and reflect revisions for permit changes, changes in our estimated reclamation costs and changes in the estimated timing of such costs.

The table below (in thousands) reflects the changes to our ARO:

	2011	2010
Balance beginning of year	$ 1,150	$ 922
Accretion	76	66
Change in cost estimate		
Additions	1,050	162
Balance end of year	$ 2,276	$ 1,150

Statement of Cash Flows

Cash equivalents include investments with maturities when purchased of three months or less.

Income Taxes

Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on pretax financial income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting and principally relate to differences in the tax basis of assets and liabilities and their reported amounts, using enacted tax rates in effect for the year in which differences are expected to reverse.

Earnings per Share

Basic earnings per share are computed on the basis of the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share is computed on the basis of the weighted average number of shares of common stock plus the effect of dilutive potential common shares outstanding during the period using the treasury stock method. Dilutive potential common shares include outstanding stock options and restricted stock units.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires us 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 revenue and expenses during the reporting period. Actual amounts could differ from those estimates. The most significant estimates included in the preparation of the financial statements are related to deferred income tax assets and liabilities and coal reserves.

Revenue Recognition

We recognize revenue from coal sales at the time risk of loss passes to the customer at contracted amounts and amounts are deemed collectible.

Long-term Contracts

We evaluate each of our contracts to determine whether they meet the definition of a derivative and they do not. As of December 31, 2011, we are committed to supply to three customers about 7 million tons of coal during the next three years. These contracts represent about 15% of our recoverable reserves for the Carlisle mine. During 2011 and 2010, three of our customers accounted for 90% or more of our sales: for 2011 one customer accounted for 43%, the second for 29%, and the third for 17%; for 2010 one customer accounted for 45%, the second for 36%, and the third for 17%. We are paid every two to four weeks and do not expect any credit losses.

Stock-based Compensation

Stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as expense over the applicable vesting period of the stock award (generally three to four years) using the straight-line method.

New Accounting Pronouncements

None of the recent FASB pronouncements will have any material effect on us.

Subsequent Events

We have evaluated all subsequent events through the date the financial statements were issued. No material recognized or non-recognizable subsequent events were identified.

(2) Income Taxes (in thousands)

Our income tax is different than the expected amount computed using the applicable federal and state statutory income tax rates. The reasons for and effects of such differences for the years ended December 31 are below:

	2011	2010
Expected amount	$ 19,859	$ 12,820
State income taxes, net of federal benefit	2,950	1,808
Other	(1,878)	(374)
	$ 20,931	$ 14,254

The deferred tax assets and liabilities resulting from temporary differences between book and tax basis are comprised of the following at December 31:

	2011	2010
Long-term deferred tax assets:		
AMT credit carryforwards	$ 1,137	$ 1,162
Stock-based compensation	596	113
Investment in Savoy	960	1,575
Oil and gas properties	1,540	873
Net long-term deferred tax assets	4,233	3,723
Long-term deferred tax liabilities:		
Coal properties	(35,333)	(21,158)
Net deferred tax liability	$ 31,100	$ 17,435

For financial accounting purposes the 2009 Sunrise Coal buyout was treated as an equity transaction among members of a controlled group. For income tax purposes we were able to increase our tax basis in the coal properties and will receive future tax deductions; accordingly, a deferred tax asset of $13 million was recognized with the credit recorded directly to additional paid-in capital. Upon further analysis, in preparing the 2010 tax provision we determined that the tax basis of the incremental assets acquired was less than that originally calculated. As such, in 2010, we reduced our deferred tax assets by $2.37 million with an offset to additional paid-in capital.

We have AMT credit carryforwards of about $1 million.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. None of our corporate tax returns have been examined in the last ten years. We were recently advised by the IRS that they will perform an examination of our 2009 and 2010 tax returns; such exam is to commence in mid-March 2012. We were also notified by Indiana tax representatives that they will examine our 2008-2010 tax returns; such exam is to commence this summer. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. Therefore, no reserves for uncertain income tax positions have been recorded.

(3) Stock Compensation Plans

Restricted Stock Units

At December 31, 2011 we had 636,000 Restricted Stock Units (RSUs) outstanding and about 922,000 available for future issuance. The outstanding RSUs have a value of about $6.4 million based on our current stock price of about $10. During April 2010 we issued 126,500 RSUs with cliff vesting over three years. On the date of issuance of the RSUs our stock was selling for $8.40. During 2011, 30,000 RSUs were granted with cliff vesting over three years; our stock closed at about $11 on grant date. We expect 268,000 RSUs to vest during 2012 under our current vesting schedule. Every two years we consider granting RSUs to our mine managers; we expect to issue grants in 2012 but have yet to decide the amount.

During December 2011 and 2010, 195,000 RSUs vested each year. On vesting date the shares had a value of about $2 million for 2011 and about $2.3 million for 2010. Under our RSU plan participants are allowed to relinquish shares to pay for their required minimum statutory income taxes.

Stock based compensation expense for 2011 and 2010 was about $2.2 million for each year. For 2012 based on existing RSUs outstanding, stock based compensation expense will be about $2.1 million.

Stock Options

On January 7, 2010 we allowed four Denver employees (non officers) a one-time opportunity to relinquish 1/3 of their vested options (115,833) for cash of $679,000; the intrinsic value on such date. This transaction was treated as a charge to equity. On January 7, 2011 we allowed the same four Denver employees (non officers) the opportunity to exchange their remaining vested options (234,167) for 181,261 shares of our common stock. The exchange ratio was based on the intrinsic value of their options. These shares were issued under our Stock Bonus Plan. Under such plan our employees are allowed to relinquish shares to pay for their required minimum statutory income taxes.

Currently we have 200,000 outstanding stock options to our CEO with an exercise price of $2.30. The options are fully vested and expire in April 2015.

Stock Bonus Plan

Our stock bonus plan was authorized by our BODs in late 2009 with 250,000 shares. As mentioned above under Stock Options, during January 2011, about 140,000 shares were issued. Currently, we have about 86,000 shares left in such plan.

(4) Notes Payable

In December 2008, we entered into a new loan agreement with a bank consortium that provides for a $40 million term loan and a $30 million revolving credit facility. At December 31, 2011, we owed $17.5 million on the term loan and nil on the revolver. The debt matures in December of 2012. We pay a .5% commitment fee on the unused revolver. Substantially all of Sunrise's assets are pledged under this loan agreement and we are the guarantor. The loan agreement requires customary covenants, required financial ratios and restrictions on distributions. Closing costs on this loan agreement were about $1.2 million and are being amortized using the effective interest method over its term which ends near the end of 2012. The current interest rate is LIBOR-one month (0.25%) plus 2.50% or 2.75%.

Considering our two interest rate swap agreements, commitment fees and amortization of the closing costs, our effective interest rates for 2011 and 2010 were about 6.6% each year. One of the swaps expired in December 2011 and the other will expire in July 2012. Assuming interest rates remain stable, we expect our interest rate, not including fees and the amortization of the closing costs, to be about 3% for the last half of 2012. The recorded value of our bank debt approximates fair value as it bears interest at a floating rate.

We expect to negotiate a new loan agreement with our banks sometime before the end of the year.

(5) Equity Investment in Savoy

We own a 45% interest in Savoy Energy L.P., a private company engaged in the oil and gas business primarily in the State of Michigan. Savoy uses the successful efforts method of accounting. We account for our interest in Savoy using the equity method of accounting.

Below (in thousands) to the 100% is a condensed balance sheet at December 31, for both years and a condensed statement of operations for both years.

Condensed Balance Sheet

	2011	2010
Current assets	$ 16,200	$ 9,103
Oil and gas PP&E, net	17,973	15,978
Other	2,152	2,048
	$ 36,325	$ 27,129
Total liabilities	$ 9,469	$ 10,004
Partners' capital	26,856	17,125
	$ 36,325	$ 27,129

Condensed Statement of Operations

	2011	2010
Revenue	$ 31,997	$ 14,447
Gain on sale of unproved properties		2,225
Expenses	(19,897)	(14,438)
Net income	$ 12,100	$ 2,234

Unaudited Oil and Gas Reserve Quantity and Value Information (in thousands)

The data below is shown proportionate to our approximate 45% ownership in Savoy.

Costs incurred are as follows:

	2011
Unproved property acquisition	$ 1,202
Development	1,024
Exploration	3,990
Total	$ 6,216

	Oil (Bbls)	NGLs (Bbls)	Natural Gas (Mcf)
January 1, 2011	350	6	356
Extensions and discoveries	509	21	689
Production	(128)	(6)	(61)
Revisions to previous estimates	138	22	143
December 31, 2011	869	43	1,127
Proved developed reserves	361	22	438
Proved undeveloped reserves	508	21	689

	Proved Developed	PUDs	Total Proved
Future cash flows:			
Oil	$ 33,760	$ 47,619	$ 81,379
NGLs	1,452	1,435	2,887
Gas	2,170	3,199	5,369
Total cash flows	37,382	52,253	89,635
Future production costs	(10,866)	(12,122)	(22,988)
Future development costs	(385)	(5,196)	(5,581)
Future income tax (none since Savoy is a pass-through entity for income tax purposes)	0	0	0
Future net cash flows	26,131	34,935	61,066
10% annual discount for estimated timing of cash flows	(6,106)	(10,870)	(16,976)
Standardized measure of discounted future net cash flows	$ 20,025	$ 24,065	$ 44,090

Beginning of year	$	15,496
Sale of oil and gas produced, net of production costs		(10,374)
Net changes in prices and production costs		4,806
Extension, discoveries and improved recoveries		24,066
Revisions of previous quantity estimates		8,547
Accretion of discount		1,549
End of year	$	44,090

Average wellhead prices		
Oil (per Bbl)	$	93.60
NGLs (per Bbl)	$	66.95
Gas (per Mcf)	$	4.76

The 2011 reserve estimates shown above have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein is Mr. G. Lance Binder. Mr. Binder has been practicing consulting petroleum engineering at NSAI since 1983. Mr. Binder is a Licensed Professional Engineer in the State of Texas (No. 61794) and has over 33 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science Degree in Chemical Engineering. He meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

(6) Equity Investment in Sunrise Energy

In late December 2010 we invested $2.4 million for a 50% interest in Sunrise Energy, LLC which then purchased existing gas reserves and gathering equipment from an unrelated third party with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for coal-bed methane gas reserves on or near our underground coal reserves. Development is pending an increase in nat-gas prices. The primary reason we consummated this purchase was to protect our coal reserves from unwanted fracking by unrelated parties. They use the successful efforts method of accounting. We account for our interest using the equity method of accounting. Operations for 2010 were not material.

Below (in thousands) to the 100% is a condensed balance sheet at December 31, 2011 and a condensed statement of operations for the year then ended. Sunrise Energy's proved oil and gas reserves are not material.

Condensed Balance Sheet

		2011
Current assets	$	1,916
Oil and gas properties, net		6,236
	$	8,152
Total liabilities	$	1,558
Members' capital		6,594
	$	8,152

Condensed Statement of Operations

		2011
Revenue	$	3,951
Expenses		(2,107)
Net income	$	1,844

(7) Employee Benefits

We have no defined benefit pension plans or any post-retirement benefit plans. We offer our employees a 401(k) Plan, where we match 100% of the first 4% that an employee contributes, a bonus plan based on meeting certain production levels and a discretionary Deferred Bonus Plan for certain key employees. We also offer health benefits to all employees and their families. Our 2011 costs for the 401(k) matching were about $458,000 and our costs for health benefits were about $3.1 million. Our 2010 costs for the 401(k) matching were about $320,000 and our costs for health benefits were about $2.1 million. The 2011 amortized costs for the Deferred Bonus Plan were about $254,000 and the 2010 amortized costs were about $180,000. The costs for the production bonus plan were $910,000 in 2011 and $328,000 in 2010.

Our mine employees are also covered by workers' compensation and such costs for 2011 and 2010 were about $1.3 million and $1.5 million, respectively. Workers' compensation is a no-fault system by which individuals who sustain work related injuries or occupational diseases are compensated. Benefits and coverage are mandated by each state which include disability ratings, medical claims, rehabilitation services, and death and survivor benefits. Our operations are protected from these perils through insurance policies. Our maximum annual exposure is limited to $1 million per employee with a $4 million aggregate deductible. Based on discussions and representations from our insurance carrier we believe that our reserve for our workers' compensation benefits are adequate. We have a safety conscious work force and our worker's compensation injuries have been minimal. Our mine has been in operation for about five years.

(8) Other Long-term Assets and Other Income (loss)

	2011	2010
Long-term assets:		
Oil and gas properties	$ 336	$ 1,744
Advance coal royalties	3,205	1,863
Deferred financing costs, net	295	616
Marketable equity securities available for sale (restricted)*	2,326	
Miscellaneous	132	725
	$ 6,294	$ 4,948

*Held by Sunrise Indemnity, Inc., our wholly-owned captive insurance company.

	2011	2010
Other income (loss):		
MSHA reimbursements**	$ 1,900	
Exploration and dry hole costs	(677)	$ (1,302)
Oil and gas sales, net of expenses	231	172
Miscellaneous	851	358
	$ 2,305	$ (772)

**See "MSHA Reimbursements" in our MD&A section for a discussion of the $1.9 million.

(9) Self Insurance

In late August 2010 we decided to drop the property insurance on our underground mining equipment. We feel comfortable with this decision as such equipment is allocated among four mining units spread out over eight miles. The historical cost of such equipment is about $93 million.

(10) Gain on Sale

See “North Dakota Lease Play” in our MD&A section for a discussion of the $10.7 million gain on sale.

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

Not applicable **.**

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls

We maintain a system of disclosure controls and procedures that are designed for the purposes of ensuring that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our CEO and CFO as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our CEO and CFO of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective for the purposes discussed above.

Internal Control Over Financial Reporting (ICFR)

We are responsible for establishing and maintaining adequate ICFR. We assessed the effectiveness of our ICFR based on criteria for effective ICFR described in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment, we concluded that we maintained effective ICFR as of December 31, 2011.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include an attestation report from Ehrhardt Keefe Steiner & Hottman PC (EKSH), our auditors, regarding ICFR. Our report was not subject to attestation by EKSH pursuant to existing rules of the SEC that permits us to provide only our report in this annual report.

ITEM 9B. OTHER INFORMATION

None.

PART III

The information required for Items 10-14 are hereby incorporated by reference to that certain information in our Information Statement to be filed with the SEC during March 2012.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES .

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

See Item 8 for an index of our financial statements.

Because we are a smaller reporting company we are not required to provide financial statement schedules.

Our exhibit index is as follows:

3.1	Second Restated Articles of Incorporation of Hallador Energy Company effective December 24, 2009. (1)
3.2	By-laws of Hallador Energy Company, effective December 24, 2009 (1)
10.1	Purchase and Sale Agreement dated December 31, 2005 between Hallador Petroleum Company, as Purchaser and Yorktown Energy Partners II, L.P., as Seller relating to the purchase and sale of limited partnership interests in Savoy Energy Limited Partnership (2)
10.2	Letter of Intent dated January 5, 2006 between Hallador Petroleum Company and Sunrise Coal, LLC (3)
10.3	Subscription Agreement - by and between Hallador Petroleum Company and Yorktown Energy Partners VI, L.P., et al dated February 22, 2006. (2)
10.4	Subscription Agreements - by and between Hallador Petroleum Company and Hallador Alternative Assets Fund LLC, et al dated February 14, 2006. (3)
10.5	Continuing Guaranty, dated April 19, 2006, by Hallador Petroleum Company in favor of Old National Bank (6)
10.6	Collateral Assignment of Hallador Master Purchase/Sale Agreement, dated April 19, 2006, among Hallador Petroleum Company, Hallador Petroleum, LLLP, and Hallador Production Company and Old National Bank (6)
10.7	Reimbursement Agreement, dated April 19, 2006, between Hallador Petroleum Company and Sunrise Coal, LLC (6)
10.8	Membership Interest Purchase Agreement dated July 31, 2006 by and between Hallador Petroleum Company and Sunrise Coal, LLC. (7)
10.9	Subscription Agreements - by and between Hallador Petroleum Company and Yorktown Energy Partners VII, L.P., et al dated October 5, 2007 (7)
10.10	Purchase and Sale Agreement dated effective as of October 5, 2007 between Hallador Petroleum Company, as Purchaser and Savoy Energy Limited Partnership, as Seller (11)

10.11	First Amendment to Credit Agreement, Waiver and Ratification of Loan Documents dated June 28, 2007 by and between Sunrise Coal, LLC, Hallador Petroleum Company and Old National Bank (9)
10.12	Amended and Restated Continuing Guaranty, dated as of June 28, 2007, between Hallador Petroleum Company, Sunrise Coal, LLC, and Old National Bank. (10)
10.13	Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated as of June 28, 2007, between Hallador Petroleum Company and Victor P. Stabio (10)*
10.14	Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated as of July 19, 2007, between Hallador Petroleum Company and Brent Bilsland (11)*
10.15	Hallador Petroleum Company 2008 Restricted Stock Unit Plan. (12)*
10.16	Form of Amended and Restated Purchase and Sale Agreement dated July 24, 2008 to purchase additional minority interest from Sunrise Coal, LLC's minority members (13)
10.17	Form of Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated July 24, 2008 (13)*
10.18	Credit Agreement dated December 12, 2008, by and among Sunrise Coal, LLC, Hallador Petroleum Company as a Guarantor, PNC Bank, National Association as administrative agent for the lenders, and the other lenders party thereto. (14)
10.19	Continuing Agreement of Guaranty and Suretyship dated December 12, 2008, by Hallador Petroleum Company in favor of PNC Bank, National Association (14)
10.20	Amended and Restated Promissory Note dated December 12, 2008, in the principal amount of $13,000,000, issued by Sunrise Coal, LLC in favor of Hallador Petroleum Company (14)
10.21	Form of Purchase and Sale Agreement dated September 16, 2009 (15)
10.22	Form of Subscription Agreement dated September 15, 2009 (15)
10.23	Form of Hallador Petroleum Company Restricted Stock Unit Issuance Agreement. (15)*
10.24	2009 Stock Bonus Plan (16)*
14	Code Of Ethics For Senior Financial Officers. (5)
21.1	List of Subsidiaries (17)
23.1	Consent of EKSH, our auditors (17)
23.2	Consent of Netherland, Sewell & Associates, Inc. (17)
31	SOX 302 Certifications (17)
32	SOX 906 Certification (17)
95	Mine Safety Disclosure (17)
99	Report of Netherland, Sewell & Associates, Inc. (17)

----

(1) IBR to Form 8-K dated December 31, 2009.
(2) IBR to Form 8-K dated January 3, 2006.
(3) IBR to Form 8-K dated January 6, 2006.
(4) IBR to Form 8-K dated February 27, 2006.
(5) IBR to the 2005 Form 10-KSB.
(6) IBR to Form 8-K dated April 25, 2006.
(7) IBR to Form 8-K dated August 1, 2006.
(8) IBR to Form 10-QSB dated September 30, 2007.
(9) IBR to Form 10-QSB dated June 30, 2007.
(10) IBR to Form 8-K dated July 2, 2007.
(11) IBR to Form 10-KSB dated December 31, 2007.
(12) IBR to March 31, 2007 Form 10-Q.
(13) IBR to Form 8-K dated July 24, 2008.
(14) IBR to Form 8-K dated December 12, 2008.
(15) IBR to Form 8-K dated September 18, 2009.
(16) IBR to Form S-8 dated December 1, 2009.
(17) Filed herewith.

* Management contracts or compensatory plans.

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.

HALLADOR ENERGY COMPANY

Date: March 2, 2012

/s/W. ANDERSON BISHOP
W. Anderson Bishop, CFO and CAO

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

/s/DAVID HARDIE David Hardie	Chairman	March 2, 2012
/s/VICTOR P. STABIO Victor P. Stabio	CEO and Director	March 2, 2012
/s/BRYAN LAWRENCE Bryan Lawrence	Director	March 2, 2012
/s/BRENT BILSLAND Brent Bilsland	President and Director	March 2, 2012
/s/JOHN VAN HEUVELEN John Van Heuvelen	Director	March 2, 2012

Exhibit 21.1

List of Subsidiaries

Sunrise Coal LLC

Sunrise Energy, LLC

Sunrise Indemnity, Inc.

Savoy Energy, L.P.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-163431 and No. 333-171778) of Hallador Energy Company, of our report dated March 2, 2012, on the consolidated financial statements of Hallador Energy Company which appears in this Form 10-K for the year ended December 31, 2011.

/s/Ehrhardt Keefe Steiner & Hottman PC

March 2, 2012
Denver, Colorado

Exhibit 23.2

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

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to (i) the use of the name Netherland, Sewell, & Associates, Inc., the reference to our reserve report dated February 27, 2012 for Savoy Energy, L.P. of which Hallador Energy Company (the “Company”) owns a 45.26% equity interest, and the use of information contained therein in the Company’s 2011 Form 10-K to be filed on or about March 2, 2012, and (ii) inclusion of our summary report dated February 27, 2012, included in such Form 10-K, as Exhibit 99.

We hereby further consent to the incorporation by reference in the two Registration Statements on Form S-8 (file # 333-163431 and # 333-171778) of such information.

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Dallas, Texas
February 29, 2012

Exhibit 31.1
CERTIFICATION
I, Victor P. Stabio, certify that:

1. I have reviewed this annual report on Form 10-K of Hallador Energy Company;

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

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

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

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

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

5. The registrant's other certifying officer 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 function):

   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.

March 2, 2012 /s/VICTOR P. STABIO
Victor P. Stabio, CEO

Exhibit 31.2

CERTIFICATION

I, W. Anderson Bishop, certify that:

1. I have reviewed this annual report on Form 10-K of Hallador Energy Company;

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

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

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

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

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

5. The registrant's other certifying officer 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 function):

   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.

March 2, 2012

/s/W.ANDERSON BISHOP
W. Anderson Bishop, CFO

EXHIBIT 32

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Hallador Energy Company (the "Company"), on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacities and date indicated below, each hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

March 2, 2012

By: /s/VICTOR P. STABIO
Victor P. Stabio, CEO

/s/W.ANDERSON BISHOP
W. Anderson Bishop, CFO

Exhibit 99

February 27, 2012

Mr. W. Anderson Bishop
Hallador Energy Company
660 Lincoln Street, Suite 2700
Denver, Colorado 80264

Dear Mr. Bishop:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the Savoy Energy, L.P. (Savoy) interest in certain oil and gas properties located in Kansas, Michigan, and Oklahoma. We completed our evaluation on or about the date of this letter. It is our understanding that Hallador Energy Company (Hallador) owns a 45.26 percent equity interest in Savoy and that the 45.26 percent share of the reserves included in this report constitutes all of the proved reserves owned by Hallador. 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 conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that per-well overhead expenses are excluded for operated properties and future income taxes are excluded for all properties. Definitions are presented immediately following this letter. This report has been prepared for Hallador'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 Savoy interest in these properties, as of December 31, 2011, to be:

Category	Net Reserves Oil (Barrels)	NGL (Barrels)	Gas (MCF)	Future Net Revenue ($) Total	Present Worth at 10%
Proved Developed Producing	771,693	46,308	839,850	55,457,900	42,410,000
Proved Developed Non-Producing	25,679	1,635	128,493	2,277,800	1,834,700
Proved Undeveloped	1,123,713	47,321	1,522,832	77,188,200	53,171,600
Total Proved	1,921,085	95,264	2,491,175	134,923,900	97,416,300

The oil reserves shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in barrels that are equivalent to 42 United States gallons. Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. 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 Savoy's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Savoy's share of production taxes and 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.

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 2011. For oil and NGL volumes, the average West Texas Intermediate posted price of $92.71 barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.118 per MMBTU is adjusted by lease for energy content, transportation fees, and regional price 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 $93.60 per barrel of oil, $66.95 per barrel of NGL, and $4.762 per MCF of gas.

Operating costs used in this report are based on operating expense records of Savoy. For nonoperated properties, 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. As requested, operating costs for the operating properties include only direct lease- and field-level costs. For all properties, headquarters general and administrative overhead expenses of Savoy are not included. As requested, ad valorem taxes are included with operating costs. Operating costs are held constant throughout the lives of the properties.

Capital costs used in this report were provided by Savoy 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 Savoy's 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 held constant to the date of expenditure. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

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 gas volume and value imbalances resulting from overdelivery or underdelivery to the Savoy 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 Savoy receiving its net revenue interest share of estimated future gross gas 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, 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. 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 Savoy, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. 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/ G. Lance Binder

G. Lance Binder, P.E. 61794
Executive Vice President

Date Signed: February 27, 2012

GLB:VRD

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.
(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
(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.*

(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.