UNITED STATES
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, 2013** 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 (public float) on June 30, 2013 was $74 million based on the closing price reported that date by the NASDAQ of $8.05 per share.

As of March 6, 2014 we had 28.7 million shares outstanding.

Portions of our information statement to be filed with the SEC in connection with our annual stockholders' meeting to be held on Thursday, April 24, 2014 are incorporated by reference into Part III of this Form 10-K.

ITEM 1. BUSINESS.

See Item 7- MDA for a discussion of our business.

Regulatory Matters

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.

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. In addition, the industry is affected by significant legislation mandating certain benefits for current and retired coal miners. Numerous federal, state and local governmental permits and approvals are required for mining operations. We believe that we have obtained all permits currently required to conduct our present mining operations.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry. None of our violations to date or the monetary penalties assessed have been material.

Mine Safety and Health

We are subject to health and safety standards both at the federal and state level. The regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters.
Mine Safety and Health Administration (MSHA) is the entity responsible for monitoring compliance with the federal mine health and safety standards. MSHA has various enforcement tools that it can use, including the issuance of monetary penalties and orders of withdrawal from a mine or part of a mine. Some, but not all, of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to customers.

MSHA has taken a number of actions to identify mines with safety issues, and has engaged in a number of targeted enforcement, awareness, outreach and rulemaking activities to reduce the number of mining fatalities, accidents and illnesses. There has also been an industry-wide increase in the monetary penalties assessed for citations of a similar nature.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

Environmental Laws and Regulations

We are subject to various federal, state and local environmental laws and regulations. These laws and regulations place substantial requirements on our coal mining operations, and require regular inspection and monitoring of our mines and other facilities to ensure compliance. We are also affected by various other federal, state and local environmental laws and regulations that our customers are subject to.

Surface Mining Control and Reclamation Act. In the U.S., the Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement (OSM), established mining, environmental protection and reclamation standards for all aspects of U.S. surface mining and many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSM. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority.

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. We expect the final phase to be completed by the end of 2015.

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.

After a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Public notice of the proposed permit is given for a comment period before a permit can be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has the right to comment on and otherwise engage in the permitting process, including public hearings and through intervention in the courts. Before a SMCRA permit is issued, a mine operator must submit a bond or other form of financial security to guarantee the performance of reclamation obligations.

The SMCRA Abandoned Mine Land Fund requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund created by the Coal Industry Retiree Health Benefit Act of 1992. The fee amount can change periodically. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 to September 30, 2012, the fee was $0.315 and $0.135 per ton of surface-mined and underground-mined coal, respectively. From October 1, 2012 through September 30, 2021, the fee is $0.28 and $0.12 per ton of surface-mined and underground-mined coal, respectively. We also pay $0.03 per ton to the Indiana Department of Reclamation.

The OSM has been in the process of developing a "stream protection rule," which could result in changes to mining operations under the SMCRA program. The OSM has projected that it will issue a proposed stream protection rule in 2014. Other rulemaking proceedings have been proposed or are being considered by the OSM. Notably, the Proposed Rule for Cost Recovery for Permit Processing, Administration and Enforcement was published in March 2013. Additionally, the OSM is working on a Coal Combustion Residues rulemaking for minefill operations. The agency has projected it may publish a proposed rule by May 2014. These OSM rulemakings and others could have a direct impact on our operations.

Clean Air Act. The Clean Air Act, enacted in 1970, and comparable state laws that regulate air emissions affect our U.S. coal mining operations both directly and indirectly.

Direct impacts on coal mining and processing operations may occur through the Clean Air Act permitting requirements and/or emission control requirements relating to particulate matter (PM), sulfur dioxide and ozone. It is possible that modifications to the national ambient air quality standards (NAAQS) could directly impact our mining operations in a manner that includes, but is not limited to, requiring changes in vehicle emissions standards or resulting in newly designated non-attainment areas. Furthermore, the U.S. Environmental Protection Agency (EPA) in 2009 adopted revised rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008. Since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions.

The Clean Air Act indirectly, but more significantly, affects the U.S. coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury, PM and other substances emitted by coal-fueled electricity generating plants. The air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the Acid Rain Program, interstate transport rules, New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and New Source Review. In addition, in recent years the U.S. EPA has adopted more stringent NAAQS for PM, nitrogen oxide and sulfur dioxide. The EPA is expected to propose a more stringent ozone standard from the current standard. The Sierra Club and others requested the U.S. District Court for the Northern District of California on January 21, 2014 to order the EPA to propose a new ozone NAAQS by December 1, 2014 and issue a final rule by October 1, 2015. The actual final rule date remains unknown at this time. More stringent standards may trigger additional control technology for mining equipment, or result in additional challenges to permitting and expansion efforts. Many of these air emissions programs and regulations have resulted in litigation which has not been completely resolved.

In December 2009, the EPA published its finding that atmospheric concentrations of greenhouse gases endanger public health and welfare within the meaning of the Clean Air Act, and that emissions of greenhouse gases from new motor vehicles and motor vehicle engines are contributing to air pollution that are endangering public health and welfare within the meaning of the Clean Air Act. In May 2010, the EPA published final greenhouse gas emission standards for new motor vehicles pursuant to the Clean Air Act. Both the endangerment finding and motor vehicle standards have been the subject of litigation. Because the Clean Air Act specifies that the prevention of significant deterioration (PSD) program applies once emissions of regulated pollutants exceed either 100 or 250 tons per year (depending on the type of source), millions of sources previously unregulated under the Clean Air Act could be subject to greenhouse gas reduction measures. The EPA published a rule in June 2010 to limit the number of greenhouse gas sources that would be subject to the PSD program. In the so-called "tailoring rule," the EPA limited the regulation of greenhouse gases from certain stationary sources to those that emit more than 75,000 tons of greenhouse gases per year (for sources that would be subject to PSD permitting regardless of greenhouse gas emissions due to other emissions) or 100,000 tons of greenhouse gases per year (for sources not subject to PSD permitting for any other air emissions), measured by "carbon dioxide equivalent."

In a decision issued on June 26, 2012, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) affirmed the EPA's endangerment finding, its motor vehicle greenhouse gas rule and the tailoring rule. In a decision issued on December 20, 2012, the same court denied petitions to reconsider that decision. Petitions for review to the U.S. Supreme Court (Supreme Court) were filed, and on October 15, 2013, the Supreme Court accepted six petitions for review, but only a single question is being considered: "Whether the EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases." A decision in the case will likely come by June 2014. This review will not affect the D.C. Circuit decision upholding the EPA's 2009 "endangerment finding" with respect to greenhouse gas emissions from new motor vehicles. However, the decision could have a significant impact on EPA rules, proposed rules and rules under development that may affect the demand for coal, including the proposed NSPS for carbon dioxide emissions from new fossil fuel-fired electric utility generating units and the performance standards under development for carbon dioxide emissions from existing power plants.

Proposed NSPS for Fossil Fuel-Fired Electricity Utility Generating Units . On April 13, 2012, the EPA published for comment proposed NSPS for emissions of carbon dioxide from new fossil fuel-fired electric utility generating units. If those standards are adopted as proposed, it is unlikely, with a few possible exceptions, that any new coal-fired electric utility generating units could be constructed in the U.S. as CCS technologies are not yet commercially viable.

In light of over 2 million comments on its April 13, 2012 proposal and ongoing developments in the industry, the EPA subsequently indicated its intention to issue a new proposal. On June 25, 2013, the U.S. President directed the EPA to issue that new proposal by September 30, 2013 and to finalize it in a timely manner. On September 20, 2013, the EPA revoked its April 13, 2012 proposal and issued a new proposed NSPS for emissions of carbon dioxide from new fossil fuel-fired electric utility generating units, using section 111(b) of the Clean Air Act. On January 8, 2014, the re-proposal was published in the Federal Register, with the comment deadline stated as March 10, 2014.

The EPA has not yet proposed rules for modified sources under section 111(b) of the Clean Air Act or existing sources under section 111(d) of the Clean Air Act. However, the U.S. President directed the EPA, in the June 25, 2013 statement referred to above, to issue such standards, regulations or guidelines, as appropriate, addressing carbon pollution from existing, modified and reconstructed power plants. The President also requested that the EPA: (a) issue a proposal addressing such matters by June 1, 2014; (b) finalize it by June 1, 2015; and (c) include, in the guidelines addressing existing power plants, a requirement that states submit to the EPA implementation plans required under Section 111(d) of the Clean Air Act by June 30, 2016. We believe that any final rules issued by the EPA in this area will be challenged.

Cross State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA finalized the CSAPR, which requires 28 states from Texas eastward (not including the New England states or Delaware) to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Under the CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions was to commence in 2012 with further reductions effective in 2014. In October 2011, the EPA proposed amendments to the CSAPR to increase emission budgets in ten states, including Texas, and ease limits on market-based compliance options. While the CSAPR had an initial compliance deadline of January 1, 2012, the rule was challenged and on December 30, 2011, the D.C. Circuit stayed the rule and advised that the EPA is expected to continue administering the Clean Air Interstate Rule (CAIR) until the pending challenges are resolved. The court vacated the CSAPR on August 21, 2012, in a 2 to 1 decision, concluding that the rule was beyond the EPA's statutory authority. On October 5, 2012, the EPA petitioned for en banc review of that decision by the entire D.C. Circuit, which denied the EPA's petition on January 24, 2013. On March 29, 2013, the Solicitor General's Office, on behalf of the EPA, and, separately, certain non-governmental organizations, filed petitions for writs of certiorari with the Supreme Court seeking Supreme Court review of the D.C. Circuit's decision. The Supreme Court granted these petitions on June 24, 2013, held oral arguments on December 10, 2013 and will likely issue a decision by June 2014.

Mercury and Air Toxic Standards (MATS). On December 16, 2011, the EPA issued MATS, which imposes MACT emission limits on hazardous air emissions from new and existing coal-fueled electric generating plants. The rule also revised NSPS for nitrogen oxides, sulfur dioxides and particulate matter for new and modified coal-fueled electricity generating plants. The MACT rule provides three years for compliance and a possible fourth year as a state permitting agency may deem necessary. On March 28, 2013, the EPA issued reconsidered MACT standards for new plants that are less stringent in some aspects than the standards issued in December 2011. On June 24, 2013, certain environmental organizations and industry groups filed an appeal of these regulations in the D.C. Circuit, and oral arguments were held on December 10, 2013. The rule could result in the retirement of certain older coal plants.

Clean Water Act. The Clean Water Act of 1972 directly impacts U.S. coal mining operations by requiring effluent limitations and treatment standards for wastewater discharge from mines through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting and performance standards are requirements of NPDES permits that govern the discharge of water from mine-related point sources into receiving waters.

The U.S. Army Corps of Engineers (Corps) regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the Clean Water Act requires mining companies to obtain Corps permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

States are empowered to develop and apply “in stream” water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. “In stream” standards vary from state to state. Additionally, through the Clean Water Act section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with their water quality standards and other applicable requirements in deciding whether or not to certify the activity.

In September 2013, a draft rule identifying waters protected by the Clean Water Act was sent to the Office of Management and Budget. This draft rule may be formally proposed by the EPA in early 2014, but we believe the final rule will not likely be issued until 2015. Litigation is likely from various stakeholders. If CWA authority is eventually expanded, it may impact our operations in some areas by way of additional requirements.

National Environmental Policy Act (NEPA). NEPA, signed into law in 1970, requires federal agencies to review the environmental impacts of their decisions and issue either an environmental assessment or an environmental impact statement. We must provide information to agencies when we propose actions that will be under the authority of the federal government. The NEPA process involves public participation and can involve lengthy timeframes.

Resource Conservation and Recovery Act (RCRA). RCRA, which was enacted in 1976, affects U.S. coal mining operations by establishing "cradle to grave" requirements for the treatment, storage and disposal of hazardous wastes. Typically, the only hazardous wastes generated at a mine site are those from products used in vehicles and for machinery maintenance. Coal mine wastes, such as overburden and coal cleaning wastes, are not considered hazardous wastes under RCRA.

Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. A recent federal district court decision in the District of Columbia requires the EPA to soon submit to the court a proposed deadline for completing the agency's CCR rulemaking process. This EPA initiative is separate from the OSM CCR rulemaking mentioned above.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Although typically not applied to the coal mining sector, CERCLA, which was enacted in 1980, nonetheless may affect U.S. coal mining operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under CERCLA, joint and several liabilities may be imposed on waste generators, site owners or operators and others, regardless of fault.

Toxic Release Inventory . Arising out of the passage of the Emergency Planning and Community Right-to-Know Act in 1986 and the Pollution Prevention Act passed in 1990, the EPA's Toxic Release Inventory program requires companies to report the use, manufacture or processing of listed toxic materials that exceed established thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

Endangered Species Act (ESA). The ESA of 1973 and counterpart state legislation is intended to protect species whose populations allow for categorization as either endangered or threatened. Changes in listings or requirements under these regulations could have a material adverse effect on our our costs or our ability to mine some of our properties in accordance with our current mining plans.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. The storage of explosives is subject to strict federal regulatory requirements. The U.S. Bureau of Alcohol, Tobacco and Firearms (ATF) regulates the use of explosive blasting materials. In addition to ATF regulation, the Department of Homeland Security (DHS) is expected to finalize an ammonium nitrate security program rule in 2014. While such new regulations may result in additional costs related to our surface mining operations, such costs are not expected to have a material adverse effect on our results of operations, financial condition or cash flows.

Global Climate

In the U.S., Congress has considered legislation addressing global climate issues and greenhouse gas emissions, but to date nothing has been enacted. While it is possible that the U.S. will adopt legislation in the future, the timing and specific requirements of any such legislation are uncertain. In the absence of new U.S. federal legislation, the EPA is undertaking steps to regulate greenhouse gas emissions pursuant to the Clean Air Act. In response to the 2007 U.S. Supreme Court ruling in Massachusetts v. EPA, the EPA has commenced several rulemaking projects as described under "Regulatory Matters-U.S. - Clean Air Act."

A number of states in the U.S. have adopted programs to regulate greenhouse gas emissions. For example, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) entered into the Regional Greenhouse Gas Initiative (RGGI) in 2005, which is a mandatory cap-and-trade program to cap regional carbon dioxide emissions from power plants. In 2011, New Jersey announced its withdrawal from RGGI effective January 1, 2012. Six midwestern states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord (MGGRA) to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets. It has been reported that, while the MGGRA has not been formally suspended, the participating states are no longer pursuing it. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces entered into the Western Climate Initiative (WCI) in 2008 to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, in November 2011, the WCI announced that six states had withdrawn from the WCI, leaving California and four Canadian provinces as the remaining members. Of those five jurisdictions, only California and Quebec have adopted greenhouse gas cap-and-trade regulations to date and both programs have begun operating. Many of the states and provinces that left WCI, RGGI and MGGRA, along with many that continue to participate, have joined the new North America 2050 initiative, which seeks to reduce greenhouse gas emissions and create economic opportunities in ways not limited to cap-and-trade programs.

In the U.S., several states have enacted legislation establishing greenhouse gas emissions reduction goals or requirements. In addition, several states have enacted legislation or have in effect regulations requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power or that provide financial incentives to electricity suppliers for using renewable energy sources.

In 2013, the U.S. and a number of international development banks, including the World Bank, the European Investment Bank and the European Bank for Reconstruction and Development, announced that they would no longer provide financing for the development of new coal-fueled power plants or would do so only in narrowly defined circumstances. Other international development banks, such as the Asian Development Bank, have indicated that they will continue to provide such financing.

The Kyoto Protocol, adopted in December 1997 by the signatories to the 1992 United Nations Framework Convention on Climate Change, established a binding set of emission targets for developed nations. The U.S. signed the Kyoto Protocol but it was not ratified by the U.S. Senate. Australia ratified the Kyoto Protocol in December 2007 and became a full member in March 2008. There are continuing discussions to develop a treaty to replace the Kyoto Protocol after its expiration in 2012, including at the Cancun meetings in late 2010, the Durban meeting in late 2011 and the Doha meeting in late 2012. At the Doha meeting, an amendment to the Kyoto Protocol was adopted, which includes new commitments for certain parties in a second commitment period, from 2013 to 2020.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future. The potential financial impact on us of future laws, regulations or other policies will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such laws, regulations or other policies, the time periods over which those laws, regulations or other policies would be phased in, the state of commercial development and deployment of CCS technologies and the alternative markets for coal. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws, regulations or other policies may have on our results of operations, financial condition or cash flows.

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 electricity. The supplier base providing mining materials has been relatively consistent in recent years. Purchases of certain underground mining equipment are concentrated with one principle supplier; however, supplier competition continues to develop.

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). 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

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 (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB) and the Western Bituminous region (WB). CAPP includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. NAPP includes Maryland, Ohio, Pennsylvania and northern West Virginia. The ILB includes Illinois, Indiana and western Kentucky. The PRB is located in northeastern Wyoming and southeastern Montana. The WB 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. 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.

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. Peabody Energy Corporation (NYSE:BTU) and Alliance (NASDAQ:ARLP) are the two largest operators in the ILB producing slightly less than half the ILB's coal production.

There are some that believe natural gas (natgas) 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, natgas would gain another advantage over coal since electricity from coal produces more carbon. The potential exists for natgas producers and utilities to develop a new relationship that has not been possible historically.

Employees

Our coal operations currently employ about 370 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. All of our mines are non-union. Other than the 370 Sunrise Coal employees in Indiana, our Chairman, CFO, controller, land person and two part time administrative staff work in the Denver office.

Other

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

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.

See Item 7 MDA for a discussion of our mines.

Coal Reserve Estimates

“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.

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 five years experience estimating coal reserves.

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.

For the exploration process core samples are bagged and boxed and delivered to an independent lab for analysis. For the production process samples are taken just before the coal is placed in the rail car by the customer and delivered to an independent lab for analysis.

Prior to acquiring coal leases, we have our title abstractors or contract title abstractors conduct a preliminary title search on the property. This information provides a strong indication of the coal owner, with whom we will enter into a lease. The next step is to execute a lease with the owner, giving us control of the property. Prior to mining the coal, we verify the lessor is the coal owner with a title opinion. Prior to purchasing coal properties we follow a similar process.

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. 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, known as the “main fans”, at the base of the slope for mine ventilation. Two additional air shafts (8' and 10.5’ diameter), known as the “north fans”, 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 ste el arch construction. A 16’ hoist is about 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. Two additional 8’ diameter airshafts, the “north portal fans”, were completed in 2013 at the North Portal facility to more effectively ventilate the north units, and facilitate more efficient use of the main set and north set of air shafts to units elsewhere in the mine. All underground mining equipment is powered with electricity and underground compliant diesel.

4. The new slurry impoundment construction has been completed in 2013 as planned. The impoundment is currently being utilized as fine refuse disposal, with a final estimated storage capacity of 36 million clean tons.

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.

The Ace-in-the-Hole mine is a multi-seam open pit strip mine. The majority of the seams are sold raw, but some of the seams will be washed prior to sales depending on quality. To convert the tons sold raw the in-place tonnage is taken times a pit recovery of 94% based on seam thickness. To convert the tons sold washed the in-place tonnage is taken times a pit recovery based on seam thickness then reduced by the projected plant recovery of 72%.

Mine and Wash Plant Recovery

	Mine recovery	Wash plant recovery
Carlisle	53%	69-72%
Bulldog	45%	77%
Russellville	54%	77%

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.

Stock Price Information

Our common stock is traded on the NASDAQ Capital Market under the symbol HNRG. 64% of our stock is held by our officers, directors and their affiliates. The following table sets forth the high and low closing sales price for the periods indicated:

	High	Low
2014		
January 1 through March 5, 2014	$8.29	$7.63
2013		
Fourth quarter	8.55	6.58
Third quarter	8.41	6.82
Second quarter	8.37	6.46
First quarter	8.35	6.90
2012		
Fourth quarter	10.11	8.03
Third quarter	8.51	7.25
Second quarter	9.01	6.56
First quarter	10.83	8.70

Regular and Special Cash Dividends

On April 5, 2013 our Board of Directors approved the adoption of a regular quarterly dividend policy. During 2013 we paid three regular quarterly dividends of $.04 each on May 15, August 15 and November 15.

During 2012 we paid three special dividends; April for $.14 per share, August for $.50 and December for $.16 for a total of $.80 per share.

At March 5, 2014, we had 236 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 1,800 street name holders.

Equity Compensation Plan Information

Restricted Stock Units

At December 31, 2013 we had 164,000 Restricted Stock Units (RSUs) outstanding and 840,000 available for future issuance. The outstanding RSUs have a value of $9 million based on our current stock price of $8.21. On February 1, 2014 we granted 920,000 RSUs to key employees of which 720,000 vest equally over four years and 200,000 vest equally over two years; our stock price on grant date was $7.66 per share. In April 2012, we granted 143,000 RSUs with cliff vesting over three years; our stock closed at $9 on grant date. We expect 310,000 RSUs to vest/lapse during 2014 under our current vesting schedule.

During 2013 and 2012, there were 315,500 and 297,500 RSUs that vested, respectively. On the vesting dates the shares had a value of $2.3 million for 2013 and $2.4 million for 2012. Under our RSU Plan participants are allowed to relinquish shares to pay for their required minimum statutory income taxes.

Stock-based compensation expense for 2013 was $2.2 million and for 2012 was $2.7 million. For 2014, based on existing RSUs outstanding, stock-based compensation expense will be $2.7 million.

On February 1, 2014, our Board of Directors authorized to increase the available shares for issuance under the 2008 Restricted Stock Unit Plan by 1,500,000 shares to be used for future compensation. The total number of RSUs authorized under the plan since inception is 3,850,000.

Stock Options

On October 31, 2012 we paid our CEO $1.5 million in exchange for him relinquishing his 200,000 stock options with a $2.30 strike price. The stock was selling for $9.50 on the transaction date. We no longer have any stock options outstanding.

Stock Bonus Plan

Our stock bonus plan was authorized in late 2009 with 250,000 shares. Currently, we have about 86,000 shares left in such plan.

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 OPERATIONS.

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

Overview

The largest portion of our business is devoted to 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 exploration company with operations in Michigan and a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana. We account for our investments in Savoy and Sunrise Energy using the equity method.

Our largest contributor to revenue and earnings is the Carlisle underground coal mine located in western Indiana, about 30 miles south of Terre Haute. Over 81% of our coal sales are to customers with large scrubbed coal-fired power plants in the state of Indiana. Our mines and coal reserves are strategically located in close proximity to our primary customers, which reduces transportation costs and thus provides us with a competitive advantage with respect to those customers; our closest customer's plant is 13 miles away and the farthest Indiana customer is 100 miles away. We have access to our primary customers directly through either the CSX Corporation (NYSE: CSX) or through the Indiana Rail Road, majority owned by the CSX. During 2013 about 12% of our sales were to customers in Central Florida almost 1,000 miles away.

We see an increasing demand for coal produced in the Illinois Basin (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 Powder River Basin (PRB) and lower cost structure than Central Appalachia (CAAP) 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 CAAP cost structure that is leading to increased switching from CAAP coal to ILB coal. Some fuel switching will also occur from PRB to ILB in newly scrubbed utilities located near ILB coal supply.

Our customers have made or announced plans to make significant investments in pollution control equipment at their plants. Due to these large investments none of these plants are scheduled for retirement; thus we expect to be supplying these plants for many years. It is not economical for the smaller, older, less efficient power plants to install scrubbers and other pollution control devices; accordingly, those type plants most likely will be retired in the coming years.

Our Coal Contracts

We have close relationships with our 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 2013 and 2012 we sold 400,600 tons and 185,000 tons, respectively to an Orlando utility through an arrangement we have with an affiliate of JP Morgan. We believe these Florida sales are an indication of the trend of ILB coal replacing CAAP coal that has traditionally supplied the southeast markets. During 2013 we sold about one million tons each to two customers, about 500,000 tons to the third customer and about 400,000 tons to the fourth customer.

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

Year	Contracted Tons	Average Price/Ton
2014	3,504,000*	$42.72
2015	1,650,000	41.99
2016	689,000	40.93 **
Total	5,843,000	

*Includes about 150,000 tons from our new Ace-in-the-Hole surface mine.

**During 2013, to accommodate one of our major customers, we entered into three separate agreements that allowed them to defer 338,000 tons originally to be delivered in 2013 to sometime in 2016. Under the agreements they agreed to pay us an average of $5.36/ton over the life of the deferral periods and we recognize the revenue accordingly as required by US GAAP. Therefore, we recognized $251,000 in the fourth quarter of 2013 and will recognize $781,000 during each of the years 2014 and 2015; otherwise our average price/ton in 2016 would be $43.57.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. 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.

Current Projects

All of our underground coal reserves are high sulfur (4.5 - 6#) with a BTU content in the 11,500 range. As discussed below, the Ace surface mine is low sulfur (1.5#) with a BTU content of 11,400. We have no met coal reserves, only steam (thermal) coal reserves. We do not use outside contractors. Below is a discussion of our current projects preceded by a table of our coal reserves.

Reserve Table - Controlled Tons (in millions):

	Annual Capacity	Year-End Reserves 2013 Proven	2013 Probable	2013 Total	2012 Proven	2012 Probable	2012 Total
Carlisle (assigned)	3.4	33.5	8.6	42.1	34.2	9.3	43.5
Ace-in-the-Hole (assigned)	0.5	3.1		3.1	3.1		3.1
Bulldog (unassigned)		19.6	16.2	35.8	19.5	16.1	35.6
War Eagle (unassigned)		27.7	15.4	43.1	15.5	13.9	29.4
Total	3.9	83.9	40.2	124.1	72.3	39.3	111.6
Assigned				45.2			46.6
Unassigned				78.9			65.0
				124.1			111.6

Active Reserve (assigned) - Carlisle Mine (underground)

Our coal reserves at December 31, 2013 assigned to the Carlisle Mine were 42.1 million tons compared to beginning of year reserves of 43.5 million tons. Primarily through the execution of new leases, our reserve additions of 2.5 million tons replaced 80% of our 2013 production of 3.1 million tons. We reduced our reserves by 810,000 tons due to revised mining plans. The mine is located near the town of Carlisle, Indiana in Sullivan County and 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 and is the most economically significant coal in Indiana. The Indiana V seam has been extensively mined by underground and surface methods in the general area. The coal thickness in the project area is 4' to 7'.

The mine has several advantages as listed below:

- SO_2 - Historically, Carlisle has guaranteed a 6# SO_2 product; however, with the addition of the Ace-in-the-Hole Mine we can blend lower sulfur coal with Carlisle coal and guarantee a mid-sulfur product which should command a higher price and increase our customer base. Few mines in the ILB have the ability to offer their customers various ranges of SO_2. Carlisle has supplied coal to 11 different power plants.
- Chlorine - Our reserves have lower chlorine (<0.10%) than average ILB reserves of 0.22%. Much of the ILB's new production is located in Illinois and possesses chlorine content in excess of .30%. The relatively low chlorine content of our reserves is attractive to buyers given their desire to limit the corrosive effects of chlorine in their power plants.
- Transportation **-** Carlisle 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 more customers. Long term, the CSX anticipates our coal being shipped to southeast markets via their railroad. We sell our coal FOB the mine and substantially all of our coal is transported by rail. However, on occasion we have shipped to three power plants via truck.

New Mine (assigned) - Ace-in-the-Hole Mine (Ace) (surface)

In November 2012 we purchased for $6 million permitted fee coal reserves, coal leases and surface properties near Clay City, Indiana in Clay County. The Ace mine is 42 road miles northeast of the Carlisle Mine. We control 3.1 million tons of proven coal reserves of which we own 1.2 million tons in fee. We mine two primary seams of low sulfur coal which make up 2.9 million of the 3.1 million tons controlled. Both of the primary seams are low sulfur (2# SO_2). Mine development began in late December 2012 and we began shipping coal in late August 2013. We truck low sulfur coal from Ace to Carlisle to blend with Carlisle's high sulfur coal. Many utilities in the southeastern U.S. have scrubbers with lower sulfur limits (4# SO_2) which cannot accept the higher sulfur contents of the ILB (6# SO_2). Blending Carlisle coal to a lower sulfur specification enables us to market Carlisle coal to more customers. We currently have a contract at Carlisle which requires us to blend coal from Ace to meet sulfur specifications. We also expect to ship low sulfur coal from Ace direct to unscrubbed customers that require low sulfur (2# SO_2). We expect the maximum capacity of Ace to be 500,000 tons annually. Ace currently has 30% of its capacity contracted for 2014. We have invested $22 million in minerals, land, equipment and development as of December 31, 2013.

During the last half of 2013 we sold 10,000 high sulfur and 26,000 low sulfur tons from Ace. Ace transitioned to the production stage in October.

New Reserve (unassigned) - Bulldog Mine (underground)

We have leased roughly 19,300 acres in Vermillion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 35.8 million tons of coal reserves. A considerable amount of our leased acres has yet to receive any exploratory drilling, thus we anticipate our controlled reserves to grow as we continue drilling in 2014. The permitting process was started in the summer of 2011, and we filed the formal
permit with the state of Illinois and the appropriate Federal regulators during June 2012. We currently expect to receive an approved mining permit in the fourth quarter of 2014.

Full-scale mine development will not commence until we have a sales commitment. We estimate the costs to develop this mine to be $150 million at full capacity of three million tons annually.

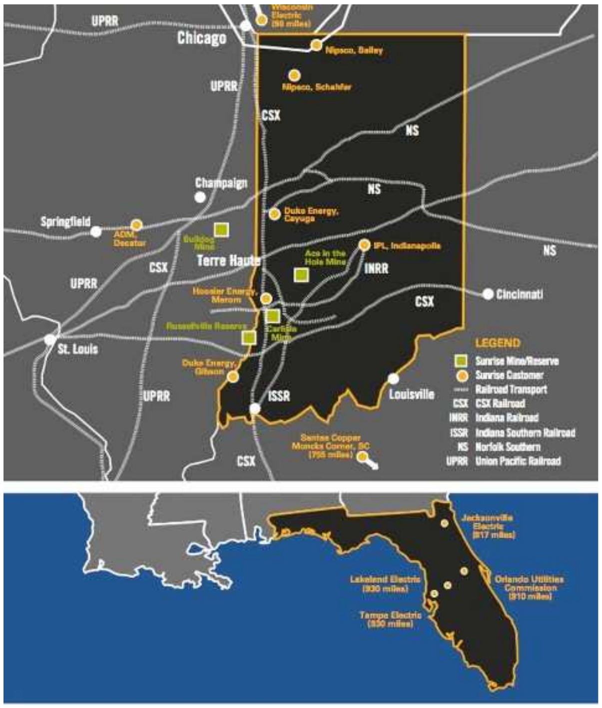
New Reserve (unassigned) – War Eagle Mine (underground)

We have leased roughly 11,000 acres in Lawrence County, Illinois near the village of Russellville. Based on our reserve estimates we currently control 43.1 million tons of coal reserves. This reserve is located about 20 miles southwest of the Carlisle Mine. Our initial testing indicates that this reserve's minability and coal quality is very similar to the Carlisle reserve.

We anticipate filing for a mining permit in late 2014. Full-scale mine development will not commence until we have a sales commitment. We estimate the costs to develop this mine to be $150 million at full capacity of 3.3 million tons annually.

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.

Below is a map that shows our mines, reserves and customer (past and present) locations.



On May 31, 2013 we purchased for $2.8 million a multi-commodity truck/barge terminal. Over 17 acres of secured area is available. The terminal is at mile point 743.8 on the Indiana bank of the Ohio River near the William Natcher Bridge between Rockport and Grandview, Indiana. Currently the dock will handle third party commodities. In the long term, we plan to ship coal through the dock. The terminal is in close proximity to the NS railroad, the CSX railroad and American Electric Power's Rockport generating power plant. We do not expect revenue from this asset until 2015. G&A expenses for this property were about $500,000 during 2013.

Liquidity and Capital Resources

Our capex budget for 2014 is about $15 million. At Carlisle we expect to spend $12 million for maintenance capex and $2.5 million for expansion capex. At Ace we estimate maintenance capex to be about $500,000. Cash from operations should fund these expenditures. In addition we have about $110 million available under our bank line.

We have no material off-balance sheet arrangements.

Capital Expenditures (capex)

For 2013 our capex was about $31.4 million allocated as follows (in 000's):

Carlisle - maintenance capex	$	14,602
Carlisle - expansion/improvements		2,973
Carlisle - land and minerals		346
Ace - mine development		4,013
Ace - surface equipment		5,858
Other projects		3,685
Items accrued for but not paid		(85)
Capex per the Cash Flow Statement	$	31,392

Results of Operations

Quarterly coal sales and cost data (in 000's):

2013	1 st	2 nd	3 rd	4 th	Full Year
Tons sold	840	774	817	757	3,188
Coal sales	$ 33,995	$ 34,149	$ 34,985	$ 34,307	$ 137,436
Average price/ton	40.47	44.12	42.82	45.32	43.11
Wash plant recovery	74.0%	70.9%	68.0%	63.2%	69.0%
Operating costs	$ 23,290	$ 22,262	$ 23,407	$ 23,934	$ 92,893
Average cost/ton	27.73	28.76	28.65	31.62	29.14
Margin	10,705	11,887	11,578	10,373	44,543
Margin/ton	12.74	15.36	14.17	13.70	13.97
Capex	8,604	6,174	8,780	7,834	31,392

2012	1 st	2 nd	3 rd	4 th	Full Year
Tons sold	701	743	810	752	3,006
Coal sales	$ 29,620	$ 32,487	$ 36,152	$ 33,111	$ 131,370
Average price/ton	42.25	43.72	44.63	44.03	43.70
Wash plant recovery	73.1%	71.2%	71.1%	71.7%	71.8%
Operating costs	$ 18,433	$ 18,816	$ 20,745	$ 21,745	$ 79,739
Average cost/ton	26.29	25.32	25.61	28.91	26.53
Margin	11,187	13,671	15,407	11,366	51,631
Margin/ton	15.96	18.40	19.02	15.12	17.17
Capex	2,372	1,857	4,993	16,987	26,209

Year	Tons	Average Sales Price/ton	Average Cost/ton	Margin/ ton	Margin (in millions)
2012	3,006,000	$ 43.70	$ 26.53	$ 17.17	$ 51.6
2013	3,188,000	43.11	29.14	13.97	44.5
2014*	3,504,000	42.72	28.50	14.22	49.8

* Sales are contracted for 2014. Average cost per ton is an estimate.

During much of 2013 we experienced difficult mining conditions and lower recoveries at Carlisle. In the fourth quarter of 2013 we experienced our highest cost of production ever due to extremely low recovery. Additionally, several production days were lost due to weather and operational issues at Carlisle. We estimate 2014 costs will be lower than 2013 due to improving recovery. We are making significant investments to our wash plant in an effort to improve recovery. The wash plant recovery for January 2014 was 68.6%. We are focused on reducing our costs to the projected $28.50/ton set forth in the table above. January 2014 costs per ton were less than the projected $28.50.

Capex in the fourth quarter of 2012 includes $9 million for the purchase of the Ace surface mine and another $4 million for land at Bulldog and Carlisle.

Other Analyses of Results of Operations

Savoy's activity is discussed below.

The increase in equity income from Sunrise Energy was due to higher natgas prices.

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

Quarterly EPS

2013

	1 st	2 nd	3 rd	4 th
Basic	$.19	$.29	$.17	$.16
Diluted	.19	.28	.17	.16

2012

	1 st	2 nd	3 rd	4 th
Basic	$.22	$.23	$.22	$.18
Diluted	.21	.23	.22	.17

MSHA Reimbursements

Some of our coal 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. We do not recognize any revenue until customers have notified us that they accept the charges.

We submitted our incurred costs for 2010 in September 2011 for $4.2 million. One of the customers agreed with our analysis and paid $2.3 million in February 2012 and the other agreed with our analysis in May 2012. Accordingly, $2.3 million was recorded in the first quarter and the other $1.9 million was recorded in the second quarter of 2012.

We submitted our incurred costs for 2011 in October 2012 for $3.7 million. $2.1 million in reimbursements were recorded in the first quarter 2013 and $1.6 million were recorded in the fourth quarter. Based on past experience we expect to collect the 2012 costs in 2014 and the 2013 costs in 2015.

Income Taxes

During 2013 our effective tax rate was 25%. For 2014, we are projecting an effective tax rate of 25% or slightly less. Based on our projections, we are forecasting a total federal and state tax obligation in excess of existing prepayments of $4.6 million, resulting in additional outlays of cash for income taxes. In addition, we expect the tax consequences between income tax and financial reporting purposes to result in a reduction to the deferred tax liability with a corresponding deferred tax benefit.

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 144,000 gross acres (about 72,000 net) in this area. During 2013 Savoy drilled 30 gross wells in this play of which 10 were dry, 17 were successful, and three are still being evaluated. During 2014 Savoy plans on drilling 20 or more 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 30 and 60% and their net revenue interest averages between 25 and 48%. Savoy's net daily oil production currently averages about 1,100 barrels. Savoy has an interest in about 96 gross wells (37 net).

Late last year Savoy engaged Energy Spectrum Advisors Inc. (ESA) to market its Trenton-Black River (TBR) operated oil properties located in southeast Michigan. ESA has offices in Dallas and Houston. More information will be posted to the ESA website in early March 2014.

The reserve quantity and value information set forth in the tables below, do not agree to the Brock Engineering Report (see Note 6 to the financial statements) as such report only includes the TBR properties. The other properties are not significant, but have been included in the tables below. The TBR properties comprise about 95% of the PV10 amounts.

We are looking forward to the opportunity to potentially effect a monetization of our Savoy investment.
The table below provides detail for Savoy's operations for 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):

	2013	2012
Revenue:		
Oil	$ 32,057	$ 25,830
NGLs (natural gas liquids)	900	926
Natgas	709	368
Contract drilling	5,409	4,555
Other	3,173	373
Total revenue	42,248	32,052
Costs and expenses:		
LOE (lease operating expenses)	3,262	2,659
Severance tax	2,476	2,015
Contract drilling costs	3,520	3,161
DD&A (depreciation, depletion & amortization)	5,802	6,387
G&G (geological and geophysical costs)	5,084	3,208
Dry hole costs	3,066	3,244
Impairment of unproved properties	3,999	3,778
Other exploration costs	451	340
G&A (general & administrative)	1,662	1,287
Stock option expense		1,448
Total expenses	29,322	27,527
Net income	$ 12,926	$ 4,525

The information below is not in thousands:

	2013	2012
Oil production – barrels	337,950	295,000
Average oil prices/barrel	$ 95.00	$ 88.00
Oil reserves in barrels	3,246,000	1,545,000
NGL reserves in barrels	218,000	64,000
Natgas reserves in Mcf	2,875,000	2,448,000
Oil prices/barrel used for PV 10	$ 94.66	$ 91.00
PV 10: proved reserves	$ 200,707,000	$ 78,000,000
PV 10: proved developed reserves	$ 105,922,000	$ 48,000,000

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

	2013	2012
PV 10: proved reserves	$ 90,820,000	$ 35,303,000
PV 10: proved developed reserves	$ 47,930,000	$ 21,725,000

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. 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. During 2012 the IRS completed an examination of our 2009 and 2010 federal tax returns and there were no significant adjustments. During 2012 the State of Indiana completed their examination of our 2008-2010 returns and no adjustments were proposed. 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.

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

Yorktown Distributions

As previously disclosed, Yorktown Energy Partners and its affiliated partnerships (Yorktown) have made eight distributions to their numerous partners totaling 6 million (750,000 per distribution) shares since May 2011. In the past these distributions were made soon after we filed our Form 10-Qs and Form 10-Ks. Currently they own 9.7 million shares of our stock representing about 34% of total shares outstanding.

We have been informed by Yorktown that they have not made any determination as to the disposition of their remaining Hallador stock. 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 such distributions will improve our liquidity and float.

If and when we are advised of another Yorktown distribution, we will timely report such on a Form 8-K.

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, 2012 and 2013, and the related consolidated statements of comprehensive income, cash flows, and stockholders' equity for each of the years in the two year period ended December 31, 2013. 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, 2012 and 2013, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ EKS&H LLLP

February 28, 2014
Denver, Colorado

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

ASSETS	2013	2012
Current assets:		
Cash and cash equivalents	$ 16,228	$ 21,888
Accounts receivable	10,577	8,127
Prepaid income taxes	4,661	
Coal inventory	4,778	2,342
Parts and supply inventory	2,826	2,264
Other	291	242
Total current assets	39,361	34,863
Coal properties, at cost:		
Land and mineral rights	26,476	22,705
Buildings and equipment	148,077	131,566
Mine development	85,333	71,046
	259,886	225,317
Less - accumulated DD&A	(77,545)	(58,479)
	182,341	166,838
Investment in Savoy	16,733	12,230
Investment in Sunrise Energy	4,573	3,969
Other assets (Note 9)	17,405	11,307
	$ 260,413	$ 229,207
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 10,357	$ 9,386
Income taxes		1,660
Total current liabilities	10,357	11,046
Long-term liabilities:		
Bank debt	16,000	11,400
Deferred income taxes	43,304	35,863
Asset retirement obligations	5,290	2,573
Other	2,128	6,316
Total long-term liabilities	66,722	56,152
Total liabilities	77,079	67,198
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; 28,751 and 28,529 outstanding, respectively	287	285
Additional paid-in capital	87,872	86,576
Retained earnings	94,796	75,118
Accumulated other comprehensive income	379	30
Total stockholders' equity	183,334	162,009
	$ 260,413	$ 229,207

See accompanying notes.

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

	2013	2012
Revenue:		
Coal sales	$ 137,436	$ 131,370
Equity income – Savoy	5,827	2,039
Equity income - Sunrise Energy	629	167
Liability extinguishment (Note 12)	4,300	
Gain on sale of land		2,748
Other income (Note 9)	5,678	4,999
	153,870	141,323
Costs and expenses:		
Operating costs and expenses	92,893	79,739
DD&A	18,585	16,028
Coal exploration costs	2,360	2,453
SG&A	7,669	7,532
Interest	1,547	1,096
	123,054	106,848
Income before income taxes	30,816	34,475
Less income taxes:		
Current	221	5,905
Deferred	7,441	4,763
	7,662	10,668
Net income*	$ 23,154	$ 23,807
Net income per share:		
Basic	$ .81	$ .84
Diluted	$ .80	$ .83
Weighted average shares outstanding:		
Basic	28,595	28,331
Diluted	28,906	28,843

*There is no material difference between net income and comprehensive income.

See accompanying notes.

Consolidated Statement of Cash Flows
For the years ended December 31,
(in thousands)

	2013	2012
Operating activities:		
Net income	$ 23,154	$ 23,807
Gain on sale		(2,748)
Liability extinguishment	(4,300)	
Deferred income taxes	7,441	4,763
Equity income – Savoy and Sunrise Energy	(6,456)	(2,206)
Cash distributions from Savoy and Sunrise Energy	1,325	1,943
DD&A	18,585	16,028
Stock-based compensation	2,155	2,655
Taxes paid on vesting of RSUs	(780)	(739)
Change in current assets and liabilities:		
Accounts receivable	(2,394)	(1,058)
Coal inventory	(2,436)	(479)
Income taxes	(6,327)	(3,465)
Accounts payable and accrued liabilities	1,130	1,060
Other	(3,916)	(2,519)
Cash provided by operating activities	27,181	37,042
Investing activities:		
Proceeds from sale of properties		7,630
Capital expenditures for coal properties	(31,392)	(26,209)
Ohio River terminal	(2,836)	
Investment in Sunrise Energy		(506)
Marketable securities		(1,221)
Other	263	(48)
Cash used in investing activities	(33,965)	(20,354)
Financing activities:		
Payments of bank debt		(7,500)
Bank borrowings	4,600	1,400
Deferred financing costs		(1,544)
Dividends	(3,476)	(23,374)
Stock option buy-out		(1,461)
Other		137
Cash provided by (used in) financing activities	1,124	(32,342)
Decrease in cash and cash equivalents	(5,660)	(15,654)
Cash and cash equivalents, beginning of year	21,888	37,542
Cash and cash equivalents, end of year	$ 16,228	$ 21,888
Cash paid for interest	$ 1,028	$ 622
Cash paid for income taxes	6,045	9,250
Increase in ARO	2,535	159

See accompanying notes.

Consolidated Statement of Stockholders' Equity
(in thousands)

	Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance January 1, 2012	28,309	$ 283	$ 85,984	$ 74,685	$ 41	$ 160,993
Stock-based compensation	20		2,655			2,655
Stock issued on vesting of RSUs	290	2				2
Taxes paid on vesting of RSUs	(90)		(739)			(739)
Stock option buy-out for cash			(1,461)			(1,461)
Dividends				(23,374)		(23,374)
Net income				23,807		23,807
Other			137		(11)	126
Balance December 31, 2012	28,529	285	86,576	75,118	30	162,009
Stock-based compensation	13		2,155			2,155
Stock issued on vesting of RSUs	316	2				2
Taxes paid on vesting of RSUs	(107)		(780)			(780)
Dividends				(3,476)		(3,476)
Net income				23,154		23,154
Other			(79)		349	270
Balance December 31, 2013	28,751	$ 287	$ 87,872	$ 94,796	$ 379	$ 183,334

See accompanying notes.

(1) Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

The consolidated financial statements include the accounts of Hallador Energy 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 mines 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 primarily in natgas operations in the same vicinity as the Carlisle mine.

Reclassification

To maintain consistency and comparability, certain amounts in the 2012 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 and surface 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 5.5% discount rate.

Federal and state laws require that mines be reclaimed 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:

	2013	2012
Balance beginning of year	$ 2,573	$ 2,276
Accretion	182	138
Additions – primarily Ace for 2013	2,535	159
Balance end of year	$ 5,290	$ 2,573

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 are 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 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, 2013, we are committed to supply to our customers 5.8 million tons of coal during the next three years. During 2013 four of our customers accounted for 94% of our coal sales: one for 39%, the second for 29%, the third for 14% and the fourth for 12%. During 2012 three of our customers accounted for 93% of our coal sales: one for 46%, the second for 31%, and the third for 16%.

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) Bill and Hold

Early in 2012 two of our customers advised us that their coal stockpiles were increasing and asked us to consider storing their coal on our property. In April 2012 we entered into a storage agreement with one customer to store 250,000 tons for a minimum of one year and up to a maximum of two years. In June 2012 we entered into a similar storage agreement with the second customer. During the 2013 second quarter we increased the storage agreement by 50,000 tons for one of the customers. We continue to sell the coal as contracted to these customers. The risks and rewards of ownership pass from us to them as coal is placed into segregated storage. We are paid a nominal storage fee in addition to our contracted price at the time the coal is placed in storage. During the first half of 2013, 145,000 tons were placed in storage for the first customer and nil for the second customer. We have recognized $7.3 million in revenue from these “bill and hold” arrangements for 2013. No tons were placed in storage during the last half of 2013. As of December 31, 2013, we have in storage 300,000 tons for the first customer and 250,000 tons for the second. There were no changes in payment terms with our customers and, as of December 31, 2013, all receivables outstanding from these two customers had been collected.

(3) 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:

	2013	2012
Expected amount	$ 10,784	$ 12,064
State income taxes, net of federal benefit	1,540	1,723
Percentage depletion	(4,373)	(1,816)
Other	(289)	(1,303)
	$ 7,662	$ 10,668

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

	2013	2012
Long-term deferred tax assets:		
Stock-based compensation	$ 372	$ 582
Investment in Savoy	1,885	1,582
Oil and gas properties	913	1,778
Net long-term deferred tax assets	3,170	3,942
Long-term deferred tax liabilities:		
Coal properties	(46,474)	(39,805)
Net deferred tax liability	$ 43,304	$ 35,863

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. During 2012 the IRS completed an examination of our 2009 and 2010 federal tax returns and there were no significant adjustments. During 2012 the State of Indiana completed their examination of our 2008-2010 returns and no adjustments were proposed. 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.

(4) Stock Compensation Plans

Restricted Stock Units

At December 31, 2013 we had 164,000 Restricted Stock Units (RSUs) outstanding and 840,000 available for future issuance. The outstanding RSUs have a value of $9 million based on our current stock price of $8.21. On February 1, 2014 we granted 920,000 RSUs to key employees of which 720,000 vest equally over four years and 200,000 over two years. Our stock price on grant date was $7.66. In April 2012, we granted 143,000 RSUs with cliff vesting over three years; our stock closed at $9 on grant date. We expect 310,000 RSUs to vest/lapse during 2014 under our current vesting schedule.

During 2013 and 2012, there were 315,500 and 297,500 RSUs that vested, respectively. On the vesting dates the shares had a value of $2.3 million for 2013 and $2.4 million for 2012. Under our RSU plan participants are allowed to relinquish shares to pay for their required minimum statutory income taxes.

Stock-based compensation expense for 2013 was $2.2 million and for 2012 was $2.7 million. For 2014, based on existing RSUs outstanding, stock-based compensation expense will be $2.7 million.

Stock Options

On October 31, 2012 we paid our CEO $1.5 million in exchange for him relinquishing his 200,000 stock options with a $2.30 strike price. The stock was selling for $9.50 on the transaction date. We no longer have any stock options outstanding.

Stock Bonus Plan

Our stock bonus plan was authorized in late 2009 with 250,000 shares. Currently, we have about 86,000 shares left in such plan.

(5) Bank Debt

During October 2012, Sunrise Coal, our wholly-owned subsidiary, entered into a new credit agreement (the "Credit Agreement") with PNC Bank, as administrative agent, and the lenders named therein. The Credit Agreement replaced the previous credit agreement we had with PNC. Closing costs on this new facility were about $1.5 million which were deferred and are being amortized over five years. Outstanding debt at December 31, 2013 was $16 million.

The Credit Agreement provides for a $165 million senior secured revolving credit facility. The facility matures in five years. The facility is collateralized by substantially all of Sunrise's assets and we are the guarantor. We will draw on the facility as needed for development of our new projects in Illinois and Indiana.

All borrowings under the Credit Agreement bear interest, at LIBOR plus 2% if the leverage ratio is less than 1.5X (which it currently is), LIBOR plus 2.5% if the leverage ratio is over 1.5 but less than 2X and at LIBOR plus 3% if the leverage ratio is over 2X. LIBOR was 17 BPS at December 31, 2013. The maximum leverage ratio is 2.75X. The leverage ratio is equal to funded debt/EBITDA. The annual commitment fee is 50 BPS but falls to 37.5 BPS if we borrow more than 33% of the facility. The maximum that we can currently borrow is $126 million due to our current covenants. The Credit Agreement also imposes certain other customary restrictions and covenants as well as certain milestones we must meet in order to draw down the full amount.

(6) Equity Investment in Savoy

We own a 45% interest in Savoy Energy L.P. (Savoy), 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

	2013	2012
Current assets	$ 29,182	$ 16,207
Oil and gas properties, net	25,408	21,065
Other	260	263
	$ 54,850	$ 37,535
Total liabilities	$ 16,447	$ 9,116
Partners' capital	38,403	28,419
	$ 54,850	$ 37,535

Condensed Statement of Operations

	2013	2012
Revenue	$ 42,248	$ 32,052
Expenses	(29,322)	(27,527)
Net income	$ 12,926	$ 4,525

Late last year Savoy engaged Energy Spectrum Advisors Inc. (ESA) to market its Trenton-Black River (TBR) oil properties located in southeast Michigan. ESA has offices in Dallas and Houston. More information will be posted to the ESA website in early March 2014.

The reserve quantity and value information set forth in the tables below, do not agree to the Brock Engineering Report as such report only includes the TBR properties. The other properties are not significant, but have been included in the tables below. The TBR properties comprise about 95% of the PV10 amounts.

We are looking forward to the opportunity to potentially effect a monetization of our Savoy investment.

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:

	2013
Unproved property acquisition	$ 1,287
Development	858
Exploration	7,061
Total	$ 9,206

	Oil (Bbls)	NGLs (Bbls)	Natgas (Mcf)
January 1, 2013	700	29	1,108
Extensions and discoveries	898	58	442
Production	(153)	(11)	(96)
Revisions to previous estimates	24	23	(153)
December 31, 2013	1,469	99	1,301
Proved developed reserves	746	60	450
Proved undeveloped reserves (PUDs)	723	39	851

	Proved Developed	PUDs	Total Proved
Future cash flows:			
Oil	$ 70,582	$ 70,662	$ 141,244
NGLs	2,551	1,669	4,220
Natgas	1,365	976	2,341
Total cash flows	74,498	73,307	147,805
Future production costs	(12,213)	(12,233)	(24,446)
Future development costs		(3,073)	(3,073)
Future income tax (none since Savoy is a pass-through entity for income tax purposes)			
Future net cash flows	62,285	58,001	120,286
10% annual discount for estimated timing of cash flows	(14,355)	(15,111)	(29,466)
Standardized measure of discounted future net cash flows	$ 47,930	$ 42,890	$ 90,820

	2013
Beginning of year	$ 35,300
Sales, net of production costs	(12,640)
Net changes in prices and production costs	1,600
Extensions and discoveries	57,200
Revisions of previous quantity estimates	2,100
Change in production timing and other	3,700
Accretion of discount	3,560
End of year	$ 90,820
Average wellhead prices:	
Oil (per Bbl)	$94.66
NGLs (per Bbl)	42.45
Natgas (per Mcf)	3.04

The 2013 reserve estimates shown above have been independently evaluated by Brock Engineering, LLC, which customarily prepares petroleum property analysis for industry and financial organizations and government agencies. Brock Engineering was founded in 1997 and performs consulting petroleum engineering services. Within Brock Engineering, the technical personnel responsible for preparing the estimates set forth in the Brock Engineering reserves report incorporated herein are Timothy J. Brock and Douglas J. Elenbaas. Mr. Brock has been practicing consulting petroleum engineering at Brock Engineering since 1997. Mr. Brock is a Licensed Professional Engineer in the State of Michigan (No. 39603) and has over 33 years of experience in the estimation and evaluation of reserves. He graduated from Michigan Technological University in 1980 with a Bachelor of Science Degree in Geological 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 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. Mr. Elenbaas has been practicing consulting petroleum engineering at Brock Engineering since 2012. Mr. Elenbaas is a Licensed Professional Engineer in the State of Michigan (No. 32030) and has over 30 years of experience in the estimation and evaluation of reserves. He graduated from the University of Michigan in 1977 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 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.

(7) Investment in Sunrise Energy

We own a 50% interest in Sunrise Energy, LLC which owns gas reserves and gathering equipment 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. They use the successful efforts method of accounting. We account for our interest 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. Sunrise Energy's proved oil and gas reserves are not material.

Condensed Balance Sheet

	2013	2012
Current assets	$ 3,109	$ 1,754
Oil and gas properties, net	6,781	6,934
	$ 9,890	$ 8,688
Total liabilities	$ 756	$ 762
Members' capital	9,134	7,926
	$ 9,890	$ 8,688

Condensed Statement of Operations

	2013	2012
Revenue	$ 3,399	$ 2,450
Expenses	(2,141)	(2,117)
Net income	$ 1,258	$ 333

(8) 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. We have 1,162 participants in our employee health plan. The plan does not cover dental, vision, short-term or long-term disability. These coverages are available on a voluntary basis. We bear some of the risk of our employee health plans. Our health claims are capped at $110,000 per person with a maximum annual exposure of $4 million not including premiums. Our 2013 expense for the 401(k) matching was $700,000 and our expense for health benefits was $4.1 million. Our 2012 expense for the 401(k) matching was $656,000 and our expense for health benefits was $3.65 million. The 2013 expense for the Deferred Bonus Plan was $467,000 and the 2012 expense was $367,000. The expense for the production bonus plan was $582,000 for 2013 and $684,000 for 2012.

Our mine employees are also covered by workers' compensation and such costs for 2013 and 2012 were about $1.3 million and $875,000, 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 includes 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 occurrence 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 is adequate. We have a safety conscious workforce and our worker's compensation injuries have been minimal.

(9) Other Long-term Assets and Other Income

	2013	2012
Long-term assets:		
Advance coal royalties	$ 4,693	$ 3,324
Deferred financing costs, net	1,195	1,494
Marketable equity securities available for sale, at fair value (restricted)*	3,889	3,548
Ohio River Terminal (see Note 11)	2,836	
Miscellaneous	4,792	2,941
	$ 17,405	$ 11,307

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

	2013	2012
Other income:		
MSHA reimbursements**	$ 3,672	$ 4,236
Coal storage fees	1,238	304
Miscellaneous	768	459
	$ 5,678	$ 4,999

**See “MSHA Reimbursements” in the MD&A section for a discussion of these amounts.

(10) Self Insurance

In late August 2010 we decided to terminate the property insurance on our underground mining equipment. Such equipment is allocated among five mining units spread out over 14 miles. The historical cost of such equipment is about $107 million.

(11) Ohio River Terminal

On May 31, 2013 we purchased for $2.8 million a multi-commodity truck/barge terminal. Over 17 acres of secured area is available. The terminal is at mile point 743.8 on the Indiana bank of the Ohio River near the William Natcher Bridge between Rockport and Grandview, Indiana. Currently the dock will handle third party commodities. In the long term, we plan to ship coal through the dock. The terminal is in close proximity to the NS railroad, the CSX railroad and American Electric Power's Rockport generating power plant. We do not expect revenue from this asset until 2015.

(12) Liability Extinguishment

During the 2013 second quarter we concluded that an approximate $4.3 million liability we recorded during 2006 upon the purchase of Sunrise relating to a terminated coal contract was no longer required. The amount had no affect on cash flows.

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, 2013.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2013 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 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 2014.

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.

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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 Halladora 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)*
10.25	$165,000,000 Revolving Credit Facility (17)
14	Code Of Ethics For Senior Financial Officers. (5)*
21.1	List of Subsidiaries (18)
23.1	Consent of EKS&H LLLP (18)
23.2	Consent of Brock Engineering, LLC (18)
31	SOX 302 Certifications (18)
32	SOX 906 Certification (18)
95	Mine Safety Disclosure (18)
99	2013 SEC Reserve Report by Brock Engineering, LLC (18)
101	Interactive data files.

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(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) IBR to Form 8-K dated October 18, 2012
(18) 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 6, 2014	/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	Director	March 6, 2014
/s/VICTOR P. STABIO Victor P. Stabio	Chairman	March 6, 2014
/s/BRYAN LAWRENCE Bryan Lawrence	Director	March 6, 2014
/s/BRENT BILSLAND Brent Bilsland	President, CEO and Director	March 6, 2014
/s/JOHN VAN HEUVELEN John Van Heuvelen	Director	March 6, 2014

Exhibit 21.1

List of Subsidiaries

Sunrise Coal LLC

Sunrise Energy, LLC

Sunrise Indemnity, Inc.

Savoy Energy, L.P.

Summit Terminal, LLC

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 February 28, 2014, on the consolidated financial statements of Hallador Energy Company which appears in this Form 10-K for the year ended December 31, 2013.

/s/ EKS&H LLLP

March 6, 2014
Denver, Colorado

EXHIBIT 23.2

Brock Engineering, LLC

771 N West Silver Lake Rd
Traverse City, MI 49685

Email: brock.engineering@yahoo.com

Phone: (231) 421-3001
Fax: (231) 421-3033

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to (i) the use of the name Brock Engineering, LLC, the reference to our reserve report dated February 12, 2014 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 Form 10-K to be filed on or about March 6, 2014, and (ii) inclusion of our summary report dated February 12, 2014, 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 (No. 333-163431 and No. 333-171778) of such information.

Brock Engineering, LLC

/s/Timothy J Brock

Timothy J Brock, PE
Its President

Traverse City, Michigan
March 6, 2014

Exhibit 31.1

CERTIFICATION

I, Brent K. Bilsland, 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 6, 2014	/s/BRENT K. BILSLAND Brent K. Bilsland, President and 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 6, 2014

/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, 2013, 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 6, 2014

By: / s/BRENT K. BILSLAND
Brent K. Bilsland, President and CEO

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

Exhibit 95 Mine Safety Disclosure

Our principles are safety, honesty, and compliance. We firmly believe that these values compose a dedicated workforce and with that come high production. The core to this is our strong training programs that include accident prevention, workplace inspection and examination, emergency response, and compliance. We work with the Federal and State regulatory agencies to help eliminate safety and health hazards from our workplace and increase safety and compliance awareness throughout the mining industry. Sunrise has not had a fatality since its establishment in 2005.

Sunrise is regulated by the MSHA under the Federal Mine Safety and Health Act of 1977 (“Mine Act”). MSHA inspects our mine on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. We present information below regarding certain violations which MSHA has issued with respect to our mine. While assessing this information please consider that the number and cost of violations will vary depending on the MSHA inspector and can be contested and appealed, and in that process, and are often reduced in severity and amount, and are sometimes dismissed. We are currently contesting four citations with MSHA; some involve the amount of the assessments and some involve the citation itself.

Sunrise has not been issued written notice from MSHA of a pattern of, or the potential to have a pattern of, violations of mandatory health or safety standards that are of such a nature as could significantly and substantially cause and effect health or safety standards under section 104(e) of the Mine Act.

The table that follows outlines citations and orders issued to us by MSHA during 2013. The citations and orders outlined below may differ from MSHA`s data retrieval system due to timing, special assessed citations, and other factors.

Definitions:

Section 104(a) Significant and Substantial Citations “S&S”: An alleged violation of a mining safety or health standard or regulation where there exists a reasonable likelihood that the hazard outlined will result in an injury or illness of a serious nature.

Section 104(b) Orders: Failure to abate a 104(a) citation within the period of time prescribed by MSHA. The result of which is an order of immediate withdraw of non-essential persons from the affected area until MSHA determines the violation has been corrected.

Section 104(d) Citations and Orders: An alleged unwarrantable failure to comply with mandatory health and safety standards.

Section 107(a) Orders: An order of withdraw for situations where MSHA has determined that an imminent danger exists.

Section 110(b)(2) Violations: An alleged flagrant violation issued by MSHA under section 110(b)(2) of the Mine Act.

Pattern or Potential Pattern of Violations: A pattern of violations of mandatory health or safety standards that are of such a nature as could have significantly and substantially contributed to the cause and effect of coal mine health or safety hazards under section 104(e) of the Mine Act or a potential to have such a pattern.

Contest of Citations, Orders, or Proposed Penalties: A contest proceeding may be filed with the Commission by the operator or miners/miners representative to challenge the issuance or penalty of a citation or order issued by MSHA.

Carlisle Mine

	Section 104(a) Citations	Section 104(b) Citations	Section 104(d) Citations/Orders	Section 107(a) Orders	Section 110(b)(2) Violations	Proposed MSHA Assessments (In thousands)
January	2	0	0	0	0	$6.00
February	5	0	0	0	0	$10.40
March	2	0	0	0	0	$3.50
April	0	0	0	0	0	$2.20
May	2	0	0	0	0	$4.50
June	1	0	0	0	0	$3.5
July	3	0	0	0	0	$5.4
August	7	0	0	0	0	$11.5
September	1	0	0	0	0	$1.7
October	0	0	0	0	0	$0.4
November	0	0	0	0	0	$1.5
December	1	0	0	0	0	$2.2
Totals	24	0	0	0	0	$52.8

Ace in the Hole Mine

	Section 104(a) Citations	Section 104(b) Citations	Section 104(d) Citations/Orders	Section 107(a) Orders	Section 110(b)(2) Violations	Proposed MSHA Assessments (In thousands)
January	0	0	0	0	0	$0.00
February	0	0	0	0	0	$0.00
March	0	0	0	0	0	$0.00
April	0	0	0	0	0	$0.00
May	1	0	1	0	0	$2.6
June	0	0	0	0	0	$0.00
July	0	0	0	0	0	$0.00
August	0	0	0	0	0	$0.00
September	0	0	0	0	0	$0.00
October	0	0	0	0	0	$0.00
November	0	0	0	0	0	$0.00
December	0	0	0	0	0	$0.00
Totals	1	0	1	0	0	$2.60

Exhibit 99

Brock Engineering, LLC

771 N West Silver Lake Rd
Traverse City, MI 49685

Email: brock.engineering@yahoo.com

Phone: (231) 421-3001
Fax: (231) 421-3033

February 12, 2014

Mr. W. Anderson Bishop
Hallador Energy Company
1660 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, 2013, to the Savoy Energy, L.P. (Savoy) interest in certain oil and gas properties located in Michigan. 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 in Southern Michigan wells in the Trenton Black-River formation. 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 Hallador interest in the Savoy Trenton Black- River properties, as of December 31, 2013, to be:

Category	OIl (Barrels)	Net Reserves NGL (Barrels)	Gas (MCF)	Future Net Revenue ($) Total	Present Worth at 10% ($)
Proved Developed Producing	629,450	50,910	376,156	52,674,800	40,429,100
Proved Developed Non- Producing	116,180	9,182	73,457	9,610,000	7,501,300
Proved Undeveloped	632,647	39,323	320,530	51,490,300	38,507,900
Total Proved	1,378,277	99,415	770,143	113,775,100	86,438,300

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 monthly prices paid to Savoy in the period January through December 2013. For hydrocarbon liquids, the average prices paid were $94.66 per barrel for Michigan crude and $42.45 per barrel for NGL. For gas volumes, the average price paid was of $3.04 per Mscf. 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 $94.66 per barrel of oil, $42.45 per barrel of NGL, and $3.04 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 over- delivery or under-delivery 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 non-confidential files of Brock Engineering, LLC 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 Brock Engineering, 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. Neither Brock Engineering, LLC nor any of Brock Engineering, LLC's engineers have any ownership interest in the properties evaluated in this report, except as follows: Brock Engineering's principle, Timothy Brock holds a minor overriding royalty interest (less than 1%) in the Palmyra Field wells. Said interest was obtained prior to drilling in this area and by virtue of a third party. We are not employed on a contingent basis.

Sincerely,

Ti mothy J B rock , P E *D ouglas* ***J*** *.* ***E*** *lenbaas , PE*

Timothy J. Brock, PE
Michigan PE # 39603

Douglas J. Elenbaas, PE
Michigan PE # 32030 Brock Engineering, LLC

Date Signed: February 12, 2014

Please be advised that the digital document you are viewing is provided by Brock Engineering as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by Brock Engineering. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

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 esti mates.

(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.