SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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FORM 10-K

MAY 06 2010

(Mark One)

☒ ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2009

Washington, DC
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☐ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 1-32955

HOUSTON AMERICAN ENERGY CORP.
(Exact name of registrant specified in its charter)

Delaware	76-0675953
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

801 Travis Street, Suite 1425, Houston, Texas 77002
(Address of principal executive offices)(Zip code)

Issuer's telephone number, including area code: (713) 222-6966

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

Title of each class	Name of each exchange on which each is registered
Common Stock, $0.001 par value	Nasdaq Global Market

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

None
(Title of Class)

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

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

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

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ 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 voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2009, based on the closing sales price of the registrant's common stock on that date, was approximately $27,345,000. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 5% or more of the outstanding common stock have been excluded from this computation in that such persons may be deemed to be affiliates.

The number of shares of the registrant's common stock, $0.001 par value, outstanding as of March 24, 2010 was 31,080,772.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2010 Annual Meeting are incorporated by reference into Part III of this Report.

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FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. These forwarding-looking statements include without limitation statements regarding our expectations and beliefs about the market and industry, our goals, plans, and expectations regarding our properties and drilling activities and results, our intentions and strategies regarding future acquisitions and sales of properties, our intentions and strategies regarding the formation of strategic relationships, our beliefs regarding the future success of our properties, our expectations and beliefs regarding competition, competitors, the basis of competition and our ability to compete, our beliefs and expectations regarding our ability to hire and retain personnel, our beliefs regarding period to period results of operations, our expectations regarding revenues, our expectations regarding future growth and financial performance, our beliefs and expectations regarding the adequacy of our facilities, and our beliefs and expectations regarding our financial position, ability to finance operations and growth and the amount of financing necessary to support operations. These statements are subject to risks and uncertainties that could cause actual results and events to differ materially. We undertake no obligation to update forward-looking statements to reflect events or circumstances occurring after the date of this annual report on Form 10-K.

As used in this annual report on Form 10-K, unless the context otherwise requires, the terms "we," "us," "the Company," and "Houston American" refer to Houston American Energy Corp., a Delaware corporation.

PART I

Item 1. Business

General

Houston American Energy Corp. is an oil and gas exploration and production company. Our oil and gas exploration and production activities are focused on development of concessions in the South American country of Colombia and development of properties in the U.S. onshore Gulf Coast Region, principally Texas and Louisiana. We seek to utilize the contacts and experience of our executive officers, particularly John F. Terwilliger and James Jacobs, to identify favorable drilling opportunities, to use advanced seismic techniques to define prospects and to form partnerships and joint ventures to spread the cost and risks to us of drilling.

Exploration Projects

Our exploration projects are focused on existing property interests, and future acquisition of additional property interests, in South America, particularly Colombia, and in the onshore Texas Gulf Coast region and Louisiana.

Each of our exploration projects differs in scope and character and consists of one or more types of assets, such as 3-D seismic data, leasehold positions, lease options, working interests in leases, partnership or limited liability company interests or other mineral rights. Our percentage interest in each exploration project ("Project Interest") represents the portion of the interest in the exploration project we share with other project partners. Because each exploration project consists of a bundle of assets that may or may not include a working interest in the project, our Project Interest simply represents our proportional ownership in the bundle of assets that constitute the exploration project. Therefore, our Project Interest in an exploration project should not be confused with the working interest that we will own when a given well is drilled. Each exploration project represents a negotiated transaction between the project partners. Our working interest may be higher or lower than our Project Interest.

The following table sets forth information relating to our principal exploration projects as of December 31, 2009:

	Net acreage	Average working interest %	Net producing wells	Net proved reserves (boe)	2009 Net Production	
					Oil (bbls)	Natural Gas (mcf)
Oklahoma	3.78	2.36	.0236	1,339	4	886
Louisiana	711.85	21.21	.1738	9,542	636	11,180
Texas	214.28	3.08	.0788	3,716	941	3,695
Total U.S.	929.91	16.95	.2762	14,597	1,581	15,761
Colombia	154,910.25	19.24	2.0320	1,202,227	129,782	—
Total	155,840.16	19.23	2.3082	1,216,824	131,363	15,761

- *United States Properties:*

In the United States, our properties and operations are principally located in the on-shore Gulf Coast region of Louisiana and Texas.

Louisiana Properties

Our principal producing and exploration properties in Louisiana consist of the following:

- **Vermilion Parish**—We hold a 22.5% working interest in the North Jade and West Jade prospects, covering 1,423 acres in Vermilion Parish Louisiana, and plan to drill an 18,500 foot test of the Camerina and Miogyp formations during 2010.
- **East Baton Rouge Parish**—We hold a 2.8125% back-in after payout in the Profit Island and North Profit Island prospects, covering 3,045 gross acres in East Baton Rouge Parish, Louisiana. In addition, we hold a 7.29% royalty interest in 2,485 royalty acres, as well as a 5.675% royalty interest in the Crown Paper #01 well.
- **Webster Parish**—We hold a 7.5% working interest and an 8.3% net revenue interest carried to point of sale for the first well in the 640 acre South Sibley Prospect in Webster Parish, Louisiana. At December 31, 2009, the South Sibley Prospect produced from a single 10,600 foot well. We have no present plans to drill additional wells on the South Sibley Prospect.

In addition to the foregoing, we hold interests in the following properties in Louisiana: the 620-acre Crowley Prospect in Acadia Parish, in which we hold a 0.15% overriding royalty interest and the 640-acre Caddo Lake Prospect in Caddo Parish, in which we hold a 33.5% working interest. We have no present plans to conduct drilling on any of these prospects.

Texas Properties

Our principal exploration properties in Texas consist of the following:

- **Karnes County**—We hold a 2.5% working interest in 6,520 acres located in Karnes County, Texas out of a 50,000 acre area of mutual interest in which we hold a 1.25% overriding royalty interest and are carried to the completion point of the first well. The operator of the Karnes County prospect has not yet indicated if or when drilling would commence on the prospect.
- **Jim Hogg County**—We hold a 4.375% working interest in the 340 acre Hog Heaven Prospect in Jim Hogg County, Texas. At December 31, 2009, the Hog Heaven Prospect produced from a single 6,200-foot well. We have no present plans to drill additional wells on the Hog Heaven Prospect.

In addition to the foregoing, we hold interests in the following non-producing property in Texas: the 91.375-acre West Turkey Prospect in Hardeman Count, Texas, in which we hold a 10.0% working interest with a 7.5% net revenue interest. We have no present plans to conduct drilling on this prospect.

- *Colombian Properties:*

We hold interests in multiple prospects in Colombia covering approximately 970,186 gross acres. Substantially all of our holdings in Colombia are located within the 125,000 square mile Llanos Basin, one of the most active drilling regions in Colombia. We identify our Colombian prospects by the prospect operator and concessions operated.

The following table sets forth information relating to our interests in prospects in Colombia at December 31, 2009:

Property	Operator	Ownership Interest	Total Gross Acres	Total Gross Developed Acres	Gross Productive Wells
Dorotea Contract	Hupecol	12.50%	51,321	800	5
Cabiona Contract	Hupecol	12.50%	86,066	640	4
Surimena Concession	Hupecol	6.25%	69,000	0	0
Las Garzas Concession	Hupecol	12.50%	103,000	320	2
Leona Concession	Hupecol	12.50%	70,343	800	5
La Cuerva Contract	Hupecol	1.60%	48,000	320	2
Los Picachos TEA	Hupecol	12.50%	86,235	0	0
CPO 4 Block	SK Energy	25.00%	345,452	0	0
Serrania Block	Shona Energy	12.50%	110,769	0	0
Total			970,186	2,880	18

Hupecol Prospects

At December 31, 2009 we held interests in six concessions and one Technical Evaluation Area ("TEA") operated by Hupecol. The six concessions are located in the Llanos Basin of Colombia and the TEA is located in the Caguan Putumayo Basin of Colombia. The six concessions and TEA cover an aggregate area of approximately 513,965 acres. Subsequent to December 31, 2009, we acquired an additional TEA (the "Macaya TEA") in the Caguan Putumayo Basin which is also operated by Hupecol. The Macaya TEA covers an area of 195,171 acres.

At December 31, 2009, five of the Hupecol concessions had production, we had interests in 18 gross wells (2.032 net wells) operated by Hupecol and our net daily production from interests operated by Hupecol was approximately 652 barrels of oil (no natural gas). Well depths range from 3,500 feet to 5,800 feet.

Our interest in each of the described concessions in Colombia is held through an interest in Hupecol, LLC and affiliated entities. We hold a 12.5% working interest in each of the prospects of Hupecol other than the Surimena concession and the La Cuerva Contract. We hold a 6.25% working interest in the Surimena concession and a 1.594674% working interest in the La Cuerva Contract.

Our working interest in each of the concessions is subject to an escalating royalty ranging from 8% to 20% depending upon production volumes and pricing and an additional 6% to 10% per concession when 5,000,000 barrels of oil have been produced on that concession.

For 2010, Hupecol has advised us that they plan to drill 12 additional wells on 6 concessions. See "Potential Sale of Certain Hupecol Holdings" below.

SK Energy Prospect

Pursuant to a Farmout Agreement and Joint Operating Agreement, we hold an interest in the 345,452 acre CPO 4 Block located in the Western Llanos Basin and operated by SK Energy Co. LTD. Under the Joint Operating Agreement, effective retroactive to May 31, 2009, SK will act as operator of the CPO 4 Block and we will pay 25.0% of all past and future cost related to the CPO 4 block, as well as an additional 12.5% of the Seismic Acquisition Costs incurred during the Phase 1 Work Program, for which we will receive a 25.0% interest in the CPO 4 Block. Our share of the past costs incurred was $194,584.

The Phase 1 Work Program consists of reprocessing approximately 400 kilometers of existing 2-D seismic data, the acquisition, processing and interpretation of a 2-D seismic program containing approximately 620 kilometers of data and the drilling of two exploration wells. The Phase 1 Work Program is estimated to be completed by June 1, 2011 and our costs for the entire Phase 1 Work Program are estimated to total approximately $15,000,000, with $10.2 million of that amount budgeted for 2010.

For 2010, SK Energy has advised us that they plan to focus on completion of seismic work on the CPO 4 Block and preparation for drilling of the initial exploration wells on the block.

Shona Energy Prospect

Pursuant to a Farmout Agreement with Shona Energy Limited we hold an interest in the 110,769 acre Serrania Block located in the Caguan Putumayo Basin. Under the Farmout Agreement we will pay 25% of designated Phase 1 geological and seismic costs in return for a 12.5% interest in the Contract for Exploration and Production covering the Block. The net costs incurred by Houston American Energy during 2009 for the Phase 1 geological and seismic costs were approximately $390 thousand.

For 2010, Shona Energy has advised us that they plan to complete seismic work on the Serrania Block and to drill two initial wells on the block. Houston American Energy's estimated net cost to complete this work is approximately $2.0 million.

Potential Sale of Certain Hupecol Holdings

In September 2009, we were advised that Hupecol had retained Scotia Waterous for purposes of evaluating a possible transaction (a "Transaction") involving the monetization of five exploration and production contracts covering approximately 413,000 acres comprising the Leona Block, La Cuerva Block, Dorotea Block, Las Garzas Block and Cabiona Block in Colombia. The Transaction may involve the sale of some or all of the assets and operations of the subject properties, an exchange or trade of assets, or other similar transaction and may be effected in a single transaction or a series of transactions. Scotia Waterous established a process whereby interested parties may evaluate a potential Transaction and has established a due date for proposals of April 6, 2010.

We are an investor in Hupecol and our interest in the assets and operations of Hupecol that would be included in any Transaction represent a substantial portion of our assets and operations in Colombia and are our principal revenue producing assets and operations. We intend to closely monitor the nature and progress of the Transaction in order to protect the interests of our company and our shareholders. However, we have no effective ability to alter or prevent a Transaction and are unable to predict whether or not a Transaction will in fact occur or the nature or timing of any such Transaction.

Further, we are unable to estimate the actual value that we might derive from any such Transaction and whether any such Transaction will ultimately be beneficial to our company and our shareholders.

Drilling Activity

During 2009, we participated in the drilling of a total of 15 gross wells, of which ten were classified as exploratory and five were classified as development. Our 2009 drilling program achieved a 60.0% success rate. The following table summarizes the number of wells drilled during 2009, 2008, and 2007, excluding any wells drilled under farmout agreements, royalty interest ownership, or any other wells in which we do not have a working interest.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	4	0.5000	6	0.7500	14	0.4339
Non-productive	1	0.1250	1	0.1250	4	0.1585
Total development wells	5	0.6250	7	0.8750	18	0.5924
Exploratory wells, completed as:						
Productive	5	0.4070	5	0.6250	4	0.5337
Non-productive	5	0.4856	4	0.4750	7	0.5661
Total exploratory wells	10	0.8926	9	1.1000	11	1.0998

Productive wells are wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

As of December 31, 2009, we had no wells in progress or awaiting completion in the United States and 1 gross (0.125 net) well in progress or awaiting completion in Colombia.

Seismic Activity

During 2009, our operators in Colombia acquired approximately 155 square miles of additional seismic and geological data. The additional data relates primarily to the Serrania and La Cuerva concessions where we hold 12.5% and 1.59% working interest, respectively. Our share of the costs of such data acquisition was $438,875.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. As of December 31, 2009, we owned interests in 26 gross wells containing multiple completions. As of December 31, 2009, we had ownership interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	1.000	7.0000
Net	0.018	0.2582
Colombia		
Gross	18.000	—
Net	2.032	—
Total		
Gross	19.000	7.0000
Net	2.050	0.2582

Volume, Prices and Production Costs

The following table sets forth certain information regarding the production volumes, average prices received and average production costs associated with our sales of gas and oil, categorized by geographic area, for each of the three years ended December 31, 2009:

	Year Ended December 31,		
	2007	2008	2009
Net Production:			
Gas (Mcf):			
United States	44,250	24,748	15,761
Colombia	—	—	—
Total	44,250	24,748	15,761
Oil (Bbls):			
United States	2,078	1,510	1,581
Colombia	69,127	122,415	129,782
Total	71,205	123,925	131,363
Average sales price:			
Gas ($ per Mcf)			
United States	6.90	10.22	4.89
Colombia	—	—	—
Total	6.90	10.22	4.89
Oil ($ per Bbl)			
United States	67.52	104.30	59.99
Colombia	65.56	83.42	61.21
Total	65.61	83.67	61.20
Average production costs ($ per BOE):			
United States	13.80	10.40	26.01
Colombia	24.75	27.03	35.95
Total	23.43	26.43	35.33

Natural Gas and Oil Reserves

Reserve Estimates

The following table sets forth, as of December 31, 2009, our net oil and natural gas reserves categorized as proved developed, proved undeveloped and total proved, and categorized by geographic area.

	Reserves		
	Oil (bbls)	**Natural Gas (mcf)**	**Total (1) (boe)**
Reserve category			
Proved Developed			
United States	2,898	70,193	14,597
Colombia	307,993	—	307,993
Total Proved Developed Reserves	310,891	70,193	322,590
Proved Undeveloped			
United States	—	—	—
Colombia	894,234	—	894,234
Total Proved Undeveloped Reserves	894,234	—	894,234
Total Proved Reserves	1,205,125	70,193	1,216,824

(1) Natural gas is converted on the basis of six mcf of gas per one barrel of oil equivalent.

Revisions to SEC Oil and Gas Reserve Reporting Requirements.

Effective December 31, 2008, the SEC effected revisions designed to modernize the oil and gas company reserves reporting requirements. The revisions are effective for annual reports filed on or after December 15, 2009. Among other things, the revised reporting requirements include:

- Commodity Prices—Economic producibility of reserves and discounted cash flows are now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves—Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserves—Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years.
- Reserves Estimation Based on New Technologies—Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserve Personnel and Estimation Process Disclosure—Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process and internal controls used to assure the objectivity of the reserve estimates.
- Disclosure by Geographic Area—Reserves in foreign countries or continents must be presented separately if they represent more than 15% of total proved reserves.

Reserve Estimation Process, Controls and Technologies.

The reserve estimates set forth above were prepared by Lonquist & Co., LLC. Lonquist & Co. also estimated the PV-10 value of our proved reserves, as of December 31, 2009, at $15,820,559. The

PV-10 value is a widely used measure of value of oil and natural gas assets and represents a before-tax present value of estimated future cash flows discounted at 10%. Due to the inherent uncertainties and the limited nature of reservoir data, proved, probable and possible reserves are subject to change as additional information becomes available. The reserves, future cash flows and present value are based on various assumptions, including those prescribed by the Securities and Exchange Commission ("SEC"), and are inherently imprecise. Although we believe the assumptions utilized are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from the amounts reflected above. Also, in computing and reporting PV-10 value, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards. The estimated present value of proved reserves does not include indirect expenses such as general and administrative expenses, debt service and future income tax expense or depletion, depreciation, and amortization.

In accordance with applicable financial accounting and reporting standards of the SEC, our proved reserves and the present value of proved reserves set forth herein were computed using average oil and natural gas sales prices as of the first trading day of each month over the twelve months ended December 31, 2009 which prices are held constant throughout the life of the properties. Quantities of proved reserves and their present value are affected by changes in oil and natural gas prices. The prices utilized for the purpose of determining our proved reserves and the present value of proved reserves as of December 31, 2009 were a WTI Cushing spot price of $61.19 per Bbl and a Henry Hub spot natural gas price of $4.24 per MMBtu, adjusted by property for energy content, quality, transportation fees, and regional price differentials. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 144.2 mboe in our Colombian reserves.

Lonquist & Co. is an independent professional engineering firm specializing in the technical and financial evaluation of oil and gas assets. Lonquist & Co's report was conducted under the direction of Don E. Charbula, P.E., Vice President of Lonquist & Co. Mr. Charbula holds a BS in Petroleum Engineering from The University of Texas at Austin and is a registered professional engineer with more than 29 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management. Lonquist & Co., and its employees, have no interest in our company and were objective in determining our reserves.

The SEC's new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Lonquist used a combination of production performance, offset analogies, seismic data and their interpretation, subsurface geologic data and core data to estimate our reserves.

Proved Undeveloped Reserves.

As of December 31, 2009, our proved undeveloped ("PUD") reserves totaled 894.2 mbls of oil and 0.0 mcf of natural gas, for a total of 894.2 mboe.

PUD Locations.

All of our PUD reserves at December 31, 2009 were associated with our properties operated by Hupecol in Colombia. We had no PUD reserves associated with our U.S. properties.

Changes in PUD Reserves.

Changes in PUD Reserves that occurred during 2009 were due to:

- Positive revisions of 894.2 mboe in PUD reserves due to the on-going drilling program and subsequent changes in subsurface mapping.
- None of the PUD reserves as of December 31, 2008 were converted to Proved Developed Producing Reserves in 2009.

Development Costs.

Estimated future development costs relating to the development of PUDs are projected to be approximately $3.681 million in 2010 and $7.594 million thereafter.

Drilling Plans.

All PUD locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2014. None of our PUD locations have been booked for longer than five years.

Developed and Undeveloped Acreage

The following table sets forth the gross and net developed and undeveloped acreage (including both leases and concessions), categorized by geographical area, which we held as of December 31, 2009:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	5,020	361	10,988	569
Colombia	2,880	325	967,306	154,585
Total	7,900	686	978,294	155,154

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

As is customary in the oil and natural gas industry, we can generally retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which we have an interest are for varying primary terms and, if production under a lease continues from our developed lease acreage beyond the primary term, we are entitled to hold the lease for as long as oil or natural gas is produced.

Many of the leases and concessions comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the acreage has been established prior to such date, in which event the lease or concession will remain in effect until the cessation of production. The following table sets forth, as of December 31, 2009, the expiration periods of the gross and net acres that are subject to leases or concessions summarized in the above table of undeveloped acreage.

	Undeveloped Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2010	—	—
December 31, 2011	1,423	320
December 31, 2012	6,520	163
December 31, 2013	—	—
December 31, 2014 and later	970,351	154,671
Total	978,294	155,154

Title to Properties

Title to properties is subject to royalty, overriding royalty, carried working, net profits, working and other similar interests and contractual arrangements customary in the gas and oil industry, liens for current taxes not yet due and other encumbrances. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than preliminary review of local records).

Investigation, including a title opinion of local counsel, generally is made before commencement of drilling operations.

Marketing

At January 1, 2010, we had no contractual agreements to sell our gas and oil production and all production was sold on spot markets.

Employees

As of March 24, 2010, we had 3 full-time employees and no part time employees. The employees are not covered by a collective bargaining agreement, and we do not anticipate that any of our future employees will be covered by such agreements.

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which we operate also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties, minimum well spacing, plugging and abandonment of wells and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

Environmental Regulation

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to our U.S. operations include, among others, the following United States federal laws and regulations:

- Clean Air Act, and its amendments, which govern air emissions;
- Clean Water Act, which governs discharges into waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as "Superfund");
- Resource Conservation and Recovery Act, which governs the management of solid waste;
- Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;
- Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Colombia has similar laws and regulations designed to protect the environment.

We routinely obtain permits for our facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations.

The ultimate financial impact of these environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on our operations. In addition, any non-compliance with such laws could subject us to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

Although we do not operate the properties in which we hold interests, noncompliance with applicable environmental laws and regulations by the operators of our oil and gas properties could expose us, and our properties, to potential costs and liabilities associated with such environmental laws. While we exercise no oversight with respect to any of our operators, we believe that each of our operators is committed to environmental protection and compliance. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Climate Change Legislation and Greenhouse Gas Regulation

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The emissions will be published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA's finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases would result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

On June 26, 2009, the United States House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACESA. On November 5, 2009 the Senate Committee on Environment and Public Works approved the "Clean Energy Jobs and American Power Act of 2009," authored by John Kerry and Barbara Boxer, that is similar in many ways to ACESA. One of the purposes of these bills is to control and reduce emissions of greenhouse gases in the United States. These bills would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% to 20% (from 2005 levels) by 2020, and by over 80% by 2050. Under these bills, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet the overall emission reduction goals of the bills. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of these bills would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. President Obama has indicated that he is in support of the adoption of legislation such as the two bills discussed above, and the White House is expending significant efforts to push for the legislation.

Two recent court decisions, one before the United States Second Circuit Court of Appeals and one before the United States Fifth Circuit Court of Appeals (The Fifth Circuit) have allowed cases to proceed. In the first case, *Connecticut v. American Electric Power*, the Second Circuit ruled that several states and other plaintiffs could continue a suit to impose GHG reductions on several utility defendants, concluding that a political question and standing objections of the defendants did not prohibit the suit from going forward. The Fifth Circuit, in *Comer v. Murphy Oil*, ruled that plaintiffs could similarly pursue a damage suit and the political question did not prohibit the suit. This case involves claims by plaintiffs who suffered damages from Hurricane Katrina that are seeking to recover damages from certain GHG emitters asserting their emissions contributed to their increased damages. In another case filed in the Texas District Court in Austin on October 6, 2009, a citizens group sued the Texas Commission on Environmental Quality (TCEQ) asserting that the agency was required to regulate carbon dioxide emissions from parties applying for permits under the Texas Clean Air Act. The result of this lawsuit could impose additional regulations on oil and gas operations in Texas, if the Texas courts require the TCEQ to regulate carbon dioxide and perhaps other GHGs such as methane. We may be subject to the EPA GHG monitoring and reporting rule, and potentially new EPA permitting rules if adopted to apply GHG permitting obligations and emissions limitations under the federal Clean Air Act. Even if no federal greenhouse gas regulations are enacted, or if the EPA issues regulations, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Foreign governments, including Colombia, have similarly begun various initiatives with respect to the regulation and reduction of GHGs. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

Web Site Access to Reports

Our Web site address is *www.houstonamericanenergy.com*. We make available, free of charge on or through our Web site, our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission.

Item 1A. Risk Factors

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;

- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices will also negatively impact the value of our proved reserves. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We May Be Affected by General Economic Conditions

The disruption experienced in U.S. and global financial and credit markets, and the accompanying economic contraction, during second half of 2008 and continuing through 2009 has resulted in projected decreases in demand for oil and natural gas, resulting in a sharp drop in energy prices, and has affected the availability and cost of capital. Prolonged negative changes in domestic and global economic conditions or disruptions of either or both of the financial and credit markets may have a material adverse effect on our results of operations, financial condition and liquidity. At this time, it is unclear whether and to what extent the actions taken by the U.S. government and other measures currently being implemented or contemplated, will mitigate the effects of the crisis. With respect to Houston American Energy, while we have no immediate need to access the credit markets in the foreseeable future, the impact of the current crisis on our ability to obtain financing in the future, if needed, and the cost and terms of same, is unclear. From an operating standpoint, the crisis experienced during the 2008-2009 period resulted in a steep decline in the price of oil and natural gas, a marked decline in the value of our reserves, a determination in March 2009 to temporarily shut-in production from our Colombian wells and reduced revenues and profitability. While prices have recovered a portion of their decline and stabilized, continued weakness and uncertainty in U.S. and global markets may result in deterioration in commodity prices and in our financial position.

A substantial percentage of our properties are undeveloped; therefore the risk associated with our success is greater than would be the case if the majority of our properties were categorized as proved developed producing.

Because a substantial percentage of our properties are unproven or proved undeveloped, we will require significant additional capital to prove and develop such properties before they may become productive. At December 31, 2009, approximately 73.5% of our proved reserves were undeveloped. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. Even if we are successful in our development efforts, it could take several years for a significant portion of our undeveloped properties to be converted to positive cash flow.

While our current business plan is to fund the development costs with funds on hand, including funds received from our 2009 offering of common stock, and cash flow from our other producing properties, if such funds are not sufficient, we may be forced to seek alternative sources for cash, through the issuance of additional equity or debt securities, borrowings or other means.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "Reserve estimates depend on many assumptions that may turn out to be inaccurate" (below) for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties, potentially negatively impacting the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have and may be required to further write down the carrying value of our oil and natural gas properties. A write-down could constitute a non-cash charge to earnings. It is likely the cumulative effect of a write-down could also negatively impact the trading price of our securities.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves reported.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activities, prevailing oil and natural gas prices and other factors, many of which are beyond our control. During the years ended December 31, 2008 and 2009, revisions to prior estimates resulted in significant negative revisions to our proved reserves in 2008 and positive revisions in 2009. Negative revisions during fiscal year 2008 amounted to 86.2% of prior year-end proved gas reserves and 83.4% of prior year-end proved oil reserves. Positive revisions during fiscal year 2009 amounted to 46.8% of prior year-end gas reserves and 8.2% of prior year-end proved oil reserves.

You should not assume that the present value of future net revenues from our proved reserves, as reported from time to time, is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on costs on the date of the estimate and average prices over the preceding twelve months. Actual future prices and costs may differ materially from those used in the present value estimate. If future prices decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our securities.

We are dependent upon third party operators of our oil and gas properties.

Under the terms of the Operating Agreements related to our oil and gas properties, third parties act as the operator of our oil and gas wells and control the drilling and operating activities to be conducted on our properties. Therefore, we have limited control over certain decisions related to activities on our properties, which could affect our results of operations. Decisions over which we have limited control include:

- the timing and amount of capital expenditures;
- the timing of initiating the drilling and recompleting of wells;
- the extent of operating costs; and
- the level of ongoing production.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are properties on which we have identified what we believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. This risk may be enhanced in our situation, due to the fact that a significant percentage of our reserves are currently proved undeveloped. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as the industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The Obama Administration has proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency ("EPA") officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Also, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas that we produce.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations in Colombia are subject to risks relating to political and economic instability.

We currently have interests in multiple oil and gas concessions in Colombia and anticipate that operations in Colombia will constitute a substantial element of our strategy going forward. The political climate in Colombia is unstable and could be subject to radical change over a very short period of time. In the event of a significant negative change in the political or economic climate in Colombia, we may be forced to abandon or suspend our operations in Colombia.

A 40-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups—both funded by the drug trade—continues in Colombia. Insurgents continue to attack civilians and violent guerilla activity continues in many parts of the country. While our operators take measures to protect our assets, operations and personnel from guerilla activity, continuing attempts to reduce or prevent guerilla activity may not be successful and guerilla activity may disrupt our operations in the future. There can also be no assurance that we can maintain the safety of our operations and personnel in Colombia or that this violence will not affect our operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to us.

Additionally, Colombia is among several nations whose eligibility to receive foreign aid from the United States is dependent on its progress in stemming the production and transit of illegal drugs, which is subject to an annual review by the President of the United States. Although Colombia is currently eligible for such aid, Colombia may not remain eligible in the future. A finding by the President that Colombia has failed demonstrably to meet its obligations under international counternarcotics agreements may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;
- the Export-Import Bank of the United States and the Overseas Private Investment Corporation would not approve financing for new projects in Colombia;
- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes; and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with ANH and Ecopetrol and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets. Accordingly, the imposition of the foregoing economic and trade sanctions on Colombia would likely result in a substantial loss and a decrease in the price of our common stock. The United States may impose sanctions on Colombia in the future, and we cannot predict the effect in Colombia that these sanctions might cause.

Our operations in Colombia are controlled by operators which may carry out transactions affecting our Colombian assets and operations without our consent.

Our operations in Colombia are subject to a substantial degree of control by the operators of the properties in which we hold interests in Colombia. We are an investor in Hupecol and our interest in the assets and operations of Hupecol represent a substantial portion of our assets and operations in Colombia and are our principal assets and operations. During 2008, Hupecol sold its interest in the Caracara Association Contract, the largest single prospect in terms of reserves and revenues in which we then held an interest. Also, during 2008, Hupecol acquired an interest in the La Cuerva Contract. In early March 2009, Hupecol determined to temporarily shut-in production from our Colombian properties and, in the fourth quarter of 2009, Hupecol commenced efforts to sell certain concessions in Colombia. It is possible that Hupecol will carry out similar sales or acquisitions of prospects or make similar decisions in the future. Our management intends to closely monitor the nature and progress of future transactions by Hupecol in order to protect our interests. However, we have no effective ability to alter or prevent a transaction and are unable to predict whether or not any such transactions will in fact occur or the nature or timing of any such transaction.

In addition to Hupecol's control of decisions regarding properties operated by Hupecol in Colombia, as minority owners, we are subject to substantial control of other properties in Colombia in which we hold interests that are operated by SK Energy and Shona Energy. Our Colombian assets consist exclusively of minority, non-operator project interests in certain Colombian assets owned and operated by Hupecol, LLC, a 25% non-operated working interest in certain Colombian assets owned and operated by SK Energy Co. LTD and a 12.5% non-operated working interest in certain Colombian assets owned and operated by Shona Energy Ltd. Our passive investments in such Colombian assets constitute our principal assets, and as a result, our financial results are directly affected by the independent strategies and decisions of Hupecol, SK Energy and Shona Energy.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to retain John F. Terwilliger, our principal executive officer, and James Jacobs, our chief financial officer, and to attract other experienced management and non-management employees, including engineers, geoscientists and other technical and professional staff. We will depend, to a large extent, on the efforts, technical expertise and continued employment of such personnel and members of our management team. If members of our management team should resign or we are unable to attract the necessary personnel, our business operations could be adversely affected.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations. As the price of oil and natural gas increases, the demand for production equipment and personnel will likely also increase, potentially resulting, at least in the near-term, in shortages of equipment and personnel. In addition, larger producers may be more likely to secure access to such equipment by virtue of offering drilling companies more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, not only would this potentially delay our ability to convert our reserves into cash flow, but could also significantly increase the cost of producing those reserves, thereby negatively impacting anticipated net income.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business.

We may operate in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil or natural gas have several adverse affects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

We may need additional financing to support operations and future capital commitments.

While we presently believe that our operating cash flows and funds on hand, including funds provided by our 2009 common stock offering, will support our ongoing operations and anticipated future capital requirements, a number of factors could result in our needing additional financing, including reductions in oil and natural gas prices, declines in production, unexpected developments in operations that could decrease our revenues, increase our costs or require additional capital contributions and commitments to new acquisition or drilling programs. In particular, given our recent commitments to participate in additional properties operated by Hupecol and our agreements to participate in the development of additional prospects in Colombia operated by Shona Energy and SK Energy, we may be subject to substantially greater calls for commitments to provide capital to support development of our additional interests. We have no commitments to provide any additional financing, if needed, and may be limited in our ability to obtain the capital necessary to support operations, complete development, exploitation and exploration programs or carry out new acquisition or drilling programs. We have not thoroughly investigated whether this capital would be available, who would provide it, and on what terms. If we are unable, on acceptable terms, to raise the required capital, our business may be seriously harmed or even terminated.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

The price of our common stock may fluctuate significantly, and this may make it difficult for you to resell common stock when you want or at prices you find attractive.

The price of our common stock constantly changes. We expect that the market price of our common stock will continue to fluctuate.

Our stock price may fluctuate as a result of a variety of factors, many of which are beyond our control. These factors include:

- quarterly variations in our operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance;

- announcements by us, our partners or our competitors of leasing and drilling activities;
- the operating and securities price performance of other companies that investors believe are comparable to us;
- future sales of our equity or equity-related securities;
- changes in general conditions in our industry and in the economy, the financial markets and the domestic or international political situation;
- fluctuations in oil and gas prices;
- departures of key personnel; and
- regulatory considerations.

In addition, in recent years, the stock market in general has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons often unrelated to their operating performance. These broad market fluctuations may adversely affect our stock price, regardless of our operating results.

The sale of a substantial number of shares of our common stock may affect our stock price.

Future sales of substantial amounts of our common stock or equity-related securities in the public market or privately, or the perception that such sales could occur, could adversely affect prevailing trading prices of our common stock and could impair our ability to raise capital through future offerings of equity or equity-related securities. No prediction can be made as to the effect, if any, that future sales of shares of common stock or the availability of shares of common stock for future sale will have on the trading price of our common stock.

Our charter and bylaws, as well as provisions of Delaware law, could make it difficult for a third party to acquire our company and also could limit the price that investors are willing to pay in the future for shares of our common stock.

Delaware corporate law and our charter and bylaws contain provisions that could delay, deter or prevent a change in control of our company or our management. These provisions could also discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions without the concurrence of our management or board of directors. These provisions:

- authorize our board of directors to issue "blank check" preferred stock, which is preferred stock that can be created and issued by our board of directors, without stockholder approval, with rights senior to those of our common stock;
- provide for a staggered board of directors and three-year terms for directors, so that no more than one-third of our directors could be replaced at any annual meeting;
- provide that directors may be removed only for cause; and
- establish advance notice requirements for submitting nominations for election to the board of directors and for proposing matters that can be acted upon by stockholders at a meeting.

We are also subject to anti-takeover provisions under Delaware law, which could also delay or prevent a change of control. Taken together, these provisions of our charter, bylaws, and Delaware law may discourage transactions that otherwise could provide for the payment of a premium over prevailing market prices of our common stock and also could limit the price that investors are willing to pay in the future for shares of our common stock.

Our management owns a significant amount of our common stock, giving them influence or control in corporate transactions and other matters, and their interests could differ from those of other shareholders.

At March 24, 2010, our directors and executive officers owned approximately 42% of our outstanding common stock. As a result, our current directors and executive officers are in a position to significantly influence or control the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of incorporation or bylaws, and the approval of mergers and other significant corporate transactions. Such level of control of the company may delay or prevent a change of control on terms favorable to the other shareholders and may adversely affect the voting and other rights of other shareholders.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We currently lease approximately 4,739 square feet of office space in Houston, Texas as our executive offices. Management anticipates that our space will be sufficient for the foreseeable future. The average monthly rental under the lease, which expires on May 31, 2012, is $6,682.

A description of our interests in oil and gas properties is included in "Item 1. Business."

Item 3. Legal Proceedings

We may from time to time be a party to lawsuits incidental to our business. As of March 24, 2010, we were not aware of any current, pending, or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

Item 4. (Removed and Reserved)

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock is listed on the Nasdaq Global Market ("Nasdaq") under the symbol "HUSA." The following table sets forth the range of high and low closing sale prices of our common stock, and cash dividends declared, for each quarter during the past two fiscal years.

		High	Low	Dividend
Calendar Year 2009	Fourth Quarter	$ 6.16	$3.38	$0.005
	Third Quarter	3.70	1.72	0.005
	Second Quarter	2.18	1.64	0.005
	First Quarter	4.38	1.77	0.02
Calendar Year 2008	Fourth Quarter	$ 6.01	$2.05	$ 0.02
	Third Quarter	11.23	5.25	0.02
	Second Quarter	11.22	4.02	0.00
	First Quarter	4.27	2.76	0.00

At March 16, 2010, the closing price of the common stock on Nasdaq was $14.90.

Holders

As of March 24, 2010, there were approximately 924 shareholders of record of our common stock.

Dividends

The payment of future cash dividends will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and any other factors considered relevant by the Board of Directors.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2009 with respect to the shares of our common stock that may be issued under our existing equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders (1)	1,538,998	$5.81	1,161,002
Equity compensation plans not approved by security holders	—	—	—
Total	1,538,998	$5.81	1,161,002

(1) Consists of 500,000 shares reserved for issuance under the Houston American Energy Corp. 2005 Stock Option Plan and 2,200,000 shares reserved for issuance under the Houston American Energy 2008 Equity Incentive Plan.

Item 6. Selected Financial Data

Not applicable

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

Houston American Energy was incorporated in April 2001 for the purposes of seeking oil and gas exploration and development prospects. Since inception, we have sought out prospects utilizing the expertise and business contacts of John F. Terwilliger, our founder and principal executive officer. Through the third quarter of 2002, the acquisition targets were in the Gulf Coast region of Texas and Louisiana, where Mr. Terwilliger has been involved in oil and gas exploration for over 30 years. Since the fourth quarter of 2002, we have expanded our focus to include oil and gas exploration in Colombia more fully described below. Domestically and internationally, the strategy is to be a non-operating partner with exploration and production companies that have much larger resources and operations.

Overview of Operations

Our operations are exclusively devoted to natural gas and oil exploration and production.

Our focus, to date and for the foreseeable future, is the identification of oil and gas drilling prospects and participation in the drilling and production of prospects. We typically identify prospects and assemble various drilling partners to participate in, and fund, drilling activities. We may retain an interest in a prospect for our services in identifying and assembling prospects without any contribution on our part to drilling and completion costs or we may contribute to drilling and completion costs based on our proportionate interest in a prospect.

We derive our revenues from our interests in oil and gas production sold from prospects in which we own an interest, whether through royalty interests, working interest or other arrangements. Our revenues vary directly based on a combination of production volumes from wells in which we own an interest, market prices of oil and natural gas sold and our percentage interest in each prospect.

Our well operating expenses vary depending upon the nature of our interest in each prospect. We may bear no interest or a proportionate interest in the costs of drilling, completing and operating prospects on which we own an interest. Other than well drilling, completion and operating expenses, our principal operating expenses relate to our efforts to identify and secure prospects, comply with our various reporting obligations as a publicly held company and general overhead expenses.

Recent Developments

Production Levels, Commodity Prices and Revenues

Our production levels and revenues during 2009, as compared to 2008, were affected by the sale of our Caracara prospect in 2008 and the sharp decline in oil and natural gas prices that began during the second half of 2008 and continued through the third quarter of 2009. As a result of depressed commodity prices, our operator in Colombia temporarily shut-in production from a majority of our Colombian properties and we had no sales in Colombia from February 13, 2009 through April 5, 2009.

During 2008, the Caracara prospect accounted for approximately 29,954 barrels of oil (net to the Company) produced, or 24% of our oil production, and $3,005,140 of revenues.

Drilling Activity

During 2009, we drilled 14 international wells in Colombia, as follows:

- 11 wells were drilled on concessions in which we hold a 12.5% working interest, of which 7 were in production at December 31, 2009, and 4 were dry holes.
- One well was drilled on a concession in which we hold a 6.25% working interest and was a dry hole.
- 2 wells were drilled on a concession in which we hold a 1.6% working interest and were in production at December 31, 2009

During 2009, we drilled one domestic well, the Wilberts & Sons #1 (Home Run Prospect) which was a dry hole and re-completed one domestic well, the Allar # 1 which was placed into production on May 27, 2009.

At December 31, 2009, drilling operations were ongoing in Colombia on one well.

Domestic Leasehold Activity

During 2009, we acquired interests in four additional prospects in Louisiana, the N. Jade and W. Jade prospects, acquired for $67,480, and the Profit Island and North Profit Island prospects, acquired for $350,644. Subsequent to purchasing our interest in the Profit and North Profit Island prospects, on July 16, 2009 we received $353,896 from the sale of part of our interest in the Profit Island prospect. We still retain an interest in both of the prospects.

During 2009, we acquired (1) a 2.5% working interest in over 6,520 acres under lease within a 50,000 acre area of mutual interest (AMI) in Karnes County, Texas, for a purchase price of $75,000, and (2) a 1.25% Overriding Royalty in the same leases and all acreage within the AMI, for a purchase price of $100,000. Per the contract, we will be carried to the completion point on the first well.

Colombian Farm-Outs and Participations.

In June 2009, we entered into a farmout agreement with Shona Energy Limited pursuant to which we will pay 25% of designated Phase 1 geological and seismic costs relating to the Serrania Contract for Exploration and Production relating to the approximately 110,769 acre Serrania Block in Colombia and for which we will receive a 12.5% interest in the Serrania Contract.

In September 2009, we elected to participate for our percentage interest (12.5%) in the Los Picachos Technical Evaluation Agreement (the "Los Picachos TEA"). The Los Picachos TEA was entered into in August 2009 by and between the Colombian National Hydrocarbons Agency (the "ANH") and Hupecol Operating Co. LLC and encompasses an 86,235 acre region located to the west and northwest of the Serrania block, which is located in the municipalities of Uribe and La Macarena in the Department of Meta in the Republic of Colombia. As a result of the election to participate, we agreed to pay our proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the Los Picachos TEA.

On October 16, 2009, we announced the approval by the ANH of a Farmout Agreement and Joint Operating Agreement with SK Energy Co. LTD., a Korean multinational conglomerate ("SK Energy"), relating to the CPO 4 Contract for Exploration and Production (the "CPO 4 Contract") covering the 345,452 net acre CPO 4 Block located in the Western Llanos Basin in the Republic of Colombia.

Under the Joint Operating Agreement, effective retroactive to May 31, 2009, SK Energy will act as operator of the CPO 4 Block and we agreed to pay 25.0% of all past and future cost related to the CPO

4 block as well as an additional 12.5% of the Seismic Acquisition Costs incurred during the Phase 1 Work Program, for which we will receive a 25.0% interest in the CPO 4 Block. Our share of the past costs was $194,584.

The Phase 1 Work Program consists of reprocessing approximately 400 kilometers of existing 2-D seismic data, the acquisition, processing and interpretation of a 2-D seismic program containing approximately 620 kilometers of data and the drilling of two exploration wells. The Phase 1 Work Program is estimated to be completed by June 1, 2011. Our share of the costs for the entire Phase 1 Work Program are estimated to total approximately $15,000,000.

Subsequent to year-end, in February 2010, we elected to participate for our percentage interest (12.5%) in the Macaya Technical Evaluation Agreement (the "Macaya TEA"). The Macaya TEA was entered into in February 2010 by and between the ANH and Hupecol and encompasses a 195,171 acre region located to the southeast of the Serrania block. As a result of the election to participate, we agreed to pay our proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the Macaya TEA.

Acquisition Activity

In light of our debt-free capital structure, solid cash position and low overhead and in response to conditions in the oil and gas market, in particular the non-economical cost and capital structures of many operators and financiers following the sharp decline in commodity prices during the second half of 2008 continuing into early 2009, during the first half of 2009, we began actively seeking opportunistic oil and gas acquisitions.

Pursuant to those efforts, on February 4, 2009, we entered into a letter agreement (the "Letter Agreement") with Yazoo Pipeline Co., L.P. ("Yazoo"), Sterling Exploration & Production Co., L.L.C. ("Sterling"), and Matagorda Operating Company (together with Yazoo and Sterling, the "Debtors"), pursuant to which we agreed to provide debtor-in-possession financing ("DIP Financing") to the Debtors subject to approval of the Letter Agreement by the U.S. Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). On February 4, 2009, the Bankruptcy Court entered an order approving the DIP Financing on the terms set out in the Letter Agreement.

Under the terms of the Letter Agreement, we agreed to advance to the Debtors up to $300,000, with all advances bearing interest at 10% per annum and being repayable in full ninety (90) days from approval of the DIP Financing by the Bankruptcy Court, or the earlier consummation of a sale of the principal assets of the Debtors to our company. Under the Letter Agreement, we and the Debtors agreed to commence negotiations and due diligence with respect to the potential acquisition by our company of the principal assets of the Debtors based on certain financial terms described in the Letter Agreement. Advances were made under the Letter Agreement in the total amount of $115,724.

Pursuant to our rights under the Letter Agreement, after conducting due diligence with respect to the Debtors, we determined to terminate negotiations with the Debtors with respect to the potential acquisition of the assets of the Debtors. On April 10, 2009, the Debtors repaid the DIP Financing in full in the amount of $117,897, including principal and interest, and at December 31, 2009 no amounts were owed to us relative to the DIP Financing.

We intend to continue to seek out and evaluate opportunities to acquire existing oil and gas assets and operations where we determine attractive returns on invested capital can be realized in current market conditions and superior returns can be derived from a recovery in primary prices. There is no assurance, however, that we will be successful in our efforts to identify and acquire oil and gas assets or operations or that any acquisitions that may be consummated will provide the returns expected by management.

Possible Hupecol Transaction

In September 2009, we were advised that Hupecol LLC had retained Scotia Waterous for purposes of evaluating a possible transaction (a "Transaction") involving the monetization of five exploration and production contracts covering approximately 413,000 acres comprising the Leona Block, La Cuerva Block, Dorotea Block, Las Garzas Block and Cabiona Block in Colombia. The Transaction may involve the sale of some or all of the assets and operations of the subject properties, an exchange or trade of assets, or other similar transaction and may be effected in a single transaction or a series of transactions. Scotia Waterous has established a process whereby interested parties may evaluate a potential Transaction and has established a due date for proposals of April 6, 2010.

We are an investor in Hupecol and our interest in the assets and operations of Hupecol that would be included in any Transaction represent a substantial portion of our assets and operations in Colombia and are our principal revenue producing assets and operations. We intend to closely monitor the nature and progress of the Transaction in order to protect the interests of our company and our shareholders. However, we have no effective ability to alter or prevent a Transaction and are unable to predict whether or not a Transaction will in fact occur or the nature or timing of any such Transaction. Further, we are unable to estimate the actual value that we might derive from any such Transaction and whether any such Transaction will ultimately be beneficial to our company and our shareholders.

Seismic Activity

During 2009, our operators in Colombia acquired approximately 155 square miles of additional seismic and geological data. The additional data relates primarily to the Serrania and La Cuerva concessions where we hold 12.5% and 1.60% working interest, respectively. Our share of the costs of such data acquisition was $438,875.

Compensation Expense—Stock Options

During 2009, we granted 120,000 stock options to our Chief Financial Officer and 26,665 stock options to our non-employee directors. Our total non-cash compensation expense for 2009 was $1,080,128.

Sale of Common Stock

In December 2009, we sold 2,890,000 shares of common stock in a registered direct offering to select institutional investors at $4.68 per share pursuant to which we received net proceeds of approximately $12.8 million. We intend to use the net proceeds of the offering for general working capital purposes, including funding our share of costs of development of properties in which we hold interests in Colombia and in the U.S.

Dividends

During 2009, we declared and paid cash dividends to our shareholders of $0.035 per share, or an aggregate of $980,057.

Critical Accounting Policies

The following describes the critical accounting policies used in reporting our financial condition and results of operations. In some cases, accounting standards allow more than one alternative accounting method for reporting. Such is the case with accounting for oil and gas activities described below. In those cases, our reported results of operations would be different should we employ an alternative accounting method.

Full Cost Method of Accounting for Oil and Gas Activities. We follow the full cost method of accounting for oil and gas property acquisition, exploration and development activities. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisition, geological and geophysical work, delay rentals, costs of drilling, completing and equipping successful and unsuccessful oil and gas wells and related internal costs that can be directly identified with acquisition, exploration and development activities, but does not include any cost related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized unless significant amounts of oil and gas reserves are involved. No corporate overhead has been capitalized as of December 31, 2009. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves are amortized on a units-of-production method over the estimated productive life of the reserves. Unevaluated oil and gas properties are excluded from this calculation. The capitalized oil and gas property costs, less accumulated amortization, are limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) and a discount factor of 10%; (b) the cost of unproved and unevaluated properties excluded from the costs being amortized; (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (d) related income tax effects. Excess costs are charged to proved properties impairment expense.

Unevaluated Oil and Gas Properties. Unevaluated oil and gas properties consist principally of our cost of acquiring and evaluating undeveloped leases, net of an allowance for impairment and transfers to depletable oil and gas properties. When leases are developed, expire or are abandoned, the related costs are transferred from unevaluated oil and gas properties to depletable oil and gas properties. Additionally, we review the carrying costs of unevaluated oil and gas properties for the purpose of determining probable future lease expirations and abandonments, and prospective discounted future economic benefit attributable to the leases. Unevaluated oil and gas properties not subject to amortization include the following at December 31, 2008 and 2009:

	At December 31, 2008	At December 31, 2009
Acquisition costs	$ 221,253	$3,411,655
Evaluation costs	1,815,122	2,140,296
Retention costs	28,191	47,294
Total	$2,064,566	$5,599,245

The carrying value of unevaluated oil and gas prospects include $88,681 and $2,993,732 expended for properties in South America at December 31, 2008 and December 31, 2009, respectively. We are maintaining our interest in these properties and development has or is anticipated to commence within the next twelve months.

Stock-Based Compensation. We account for stock-based compensation in accordance with the provisions of FASB ASC Topic 718. We use the Black-Scholes option-pricing model, which requires the input of highly subjective assumptions. These assumptions include estimating the volatility of our common stock price over the vesting term, dividend yield, an appropriate risk-free interest rate and the number of options that will ultimately not complete their vesting requirements ("forfeitures"). Changes in the subjective assumptions can materially affect the estimated fair value of stock-based compensation and consequently, the related amount recognized on the Statements of Operations.

Results of Operations

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Oil and Gas Revenues. Total oil and gas revenues decreased 23.6%, to $8,116,275 in 2009 from $10,622,050 in 2008.

The decrease in oil and gas revenue was due to: (1) a decline in oil and gas prices received during 2009 (approximately $84,000 based on lower average gas prices realized during 2009 and approximately $2.8 million based on lower average oil prices), (2) the cessation of production and sales from the majority of our Colombian properties for 52 days in early 2009, and (3) the sale of our Caracara interest in June 2008.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2009 and 2008:

	2009	2008
Gross producing wells	26	16
Net producing wells	2.31	1.47
Net oil production (Bbls)	131,363	123,925
Net gas production (Mcf)	15,761	24,748
Oil—Average sales price per barrel	$ 61.20	$ 83.67
Gas—Average sales price per mcf	$ 4.89	$ 10.22

Production volumes were less then what they otherwise would have been in 2009 due to the sale of our Caracara interest during 2008 (accounting for 29,954 barrels of production and $3,005,140 of revenues during 2008) and the cessation of production and sales from the majority of our Colombian properties for 52 days in early 2009 as a result of unfavorable commodity prices, partially offset by increased production in fields in which we hold higher working interests (12.5% vs. 1.6% in Caracara). Giving pro forma effect to exclude sales revenues from the Caracara interest, which was sold in June 2008, oil and gas revenues for 2008 would have been $7,616,910.

The decline in average sales prices realized reflects the sharp worldwide economic decline, and accompanying decline in commodity prices, during the second half of 2008 continuing through 2009.

Oil and gas sales revenues for 2009 and 2008, by region, were as follows:

	Colombia	U.S.	Total
2009			
Oil sales	$ 7,944,353	$ 94,839	$ 8,039,192
Gas sales	$ —	$ 77,083	$ 77,083
2008			
Oil sales	$10,211,579	$157,492	$10,369,071
Gas sales	$ —	$252,979	$ 252,979

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, increased 41% to $4,746,295 in 2009 from $3,366,740 in 2008.

The increase in lease operating expenses as a percentage of revenues, from 32% of revenues in 2008 to 58% of revenues in 2009, was primarily attributable to the temporary cessation of production from a majority of our Colombian properties during the 2009 period as discussed above, the steep decline in oil and gas prices and an increase in our average working interest following the Caracara sale, as well as increased cost in Colombia relating to personnel expenses, facilities and equipment expenses, catering expenses, road maintenance, as well environmental services expenses.

Following is a summary comparison of lease operating expenses for the periods.

	Colombia	U.S.	Total
2009	$4,665,578	$ 80,717	$4,746,295
2008	$3,232,213	$134,527	$3,366,740

Hupecol, our operator in Colombia, has implemented cost cutting measures in order to improve field economics from our Colombian operations. We have also seen declines in drilling and operating costs in the Llanos Basin which, together, are expected to result in improved margins during 2010 and beyond.

Joint Venture Expenses. Joint venture expenses totaled $172,890 in 2009 compared to $183,510 in 2008. The joint venture expenses represent our allocable share of the indirect field operating and region administrative expenses billed by the operator of the Colombian concessions. The decrease in joint venture expenses was attributable to the decrease in the number of producing wells during 2009.

Depreciation and Depletion Expense. Depreciation and depletion expense decreased by 67% to $1,900,631 in 2009 from $5,816,691 in 2008. The decrease in depreciation and depletion was due to an increase in reserves due to exploration and development. This resulting increase in our reserves from exploration and development activities lowered our depreciation rate per barrel.

Impairment Expense. During 2008, we recorded a provision for impairment of oil and gas properties of $5,621,106, most of which was attributable to our South American properties. Impairments related to reduced commodity prices at year end and lower reserve estimates for our Colombian wells, reduced reserve estimates for our U.S. properties as a result of lower commodity prices and lower then expected production volumes, as well as the lack of commercial production on our Caddo Lake prospect.

Gain on sale of oil & gas properties. The sale of our Caracara assets resulted in a gain of $7,615,236 during 2008.

General and Administrative Expenses. General and administrative expense decreased by 12% to $2,768,195 in 2009 from $3,152,930 in 2008. The decrease in general and administrative expense was primarily attributable to decreases in employee compensation and professional fees, including a decrease of $750,000 related to cash bonuses paid in 2008 not repeated in 2009 and $400,320 related to restricted stocks grants in 2008.

Other Income. Other income consists of interest earned on cash balances and marketable securities. Other income totaled $64,882 in 2009 as compared to $295,375 in 2008. The decrease in other income resulted from the sale of the balance of our marketable securities during early 2008 and a reduction in interest rates on short-term cash investments, partially offset by interest earned on DIP Financing provided to the Creditors under the Letter Agreement.

Income Tax Expense/Benefit. We reported an income tax benefit of $737,406 in 2009 as compared to an income tax benefit of $73,261 in 2008.

The income tax benefit during 2009 was primarily attributable to net operating losses generated in Colombia and the United States and the refund during 2009 of approximately $548,000 of Colombian taxes. The income tax benefit during 2009 was attributable $402,663 to the U.S. and $334,743 to Colombia.

The income tax benefit during 2008 was primarily attributable to a decrease in valuation allowance and the availability of U.S. foreign tax credits that more than offset taxes attributable to operating income in Colombia. A deferred income tax benefit in the amount of $5,273,567 was attributable to the U.S. and income tax expense in the amount of $5,200,306 was attributable to Colombia during 2008. Income tax expense during 2008 was entirely attributable to operations in Colombia.

At December 31, 2009, we had foreign tax credit carryovers of $1,684,745. Currently, we expect to be able to utilize the incremental foreign tax credit carry forward and net operating loss generated during 2009 and, therefore, no additional valuation allowance has been recorded to date.

Financial Condition

Liquidity and Capital Resources. At December 31, 2009, we had a cash balance of $14,010,637 and working capital of $16,365,490 compared to a cash balance of $9,910,694 and working capital of $10,536,834 at December 31, 2008. The increase in working capital during the period was primarily attributable to the receipt of $12,763,550 (net proceeds) from the sale of common stock in December 2009, partially offset by payment of drilling costs, acquisition costs, operating costs in Colombia and dividends.

Cash Flows. Operating activities used cash during 2009 totaling $484,677 as compared to $1,452,054 of cash provided by operations during 2008. The decrease in cash flows from operations was primarily a result of a decrease in revenue due to lower commodity prices and the shut-in of Colombian production for part of the year.

Investing activities used $7,201,763 during 2009 compared to $8,787,853 provided during 2008. The funds used by investing activities during 2009 reflect investments in oil and gas properties and assets of $8,273,545 partially offset by the receipt of $799,680 from the escrow account related to the sale of the Caracara assets and $397,102 from the sale of selected domestic prospects, including Profit Island and North Profit Island. The funds provided by investing activities during 2008 reflect the receipt of proceeds from the sale of the Caracara assets totaling $9,878,797 and the Home Run and North Henry Bayou prospects totaling $273,696, as well as the net sale of marketable securities of $9,650,000, partially offset by investments in oil and gas properties and assets of $10,841,353.

Financing activities provided $11,786,383 during 2009 compared to $747,031 used during 2008. Funds provided by financing activities during 2009 consisted of proceeds from the December 2009 common stock placement of $13,525,200, partially offset by cash dividends paid of $980,057 and cost associated with our registered direct offering of $758,760. Funds used by financing activities during 2008 consisted of cash dividends paid in the amount of $1,122,031, partially offset by the receipt of $375,000 from the exercise of outstanding warrants.

Long-Term Liabilities. At December 31, 2009, we had long-term liabilities of $332,912 as compared to $205,524 at December 31, 2008. Long-term liabilities at December 31, 2009 and December 31, 2008 consisted of a reserve for plugging costs and deferred rent liability. The increase in 2009 of long-term liabilities was a result of increased plugging cost from drilling in Colombia.

Capital and Exploration Expenditures and Commitments. Our principal capital and exploration expenditures relate to our ongoing efforts to acquire, drill and complete prospects. We expect that future capital and exploration expenditures will be funded principally through funds generated from operations and funds on hand, including funds generated from our 2009 sale of common stock.

During 2009, we invested approximately $8,273,545 for the acquisition and development of oil and gas properties, which included expenses related to (1) drilling of 14 wells in Colombia ($3,731,322),

(2) seismic and geological costs in Colombia ($528,529), (3) delay rentals on U.S. properties ($19,112), (4) leasehold costs on U.S. properties ($1,098,704), (5) capital expenditures on U.S. wells ($335,070) and (6) acquisition and evaluation costs in Colombia ($2,560,808).

At December 31, 2009, our only material contractual obligation requiring determinable future payments on our part was our lease relating to our executive offices.

The following table details our contractual obligations as of December 31, 2009:

	Payments due by period				
	Total	**< 1 year**	**1-3 years**	**3-5 years**	**> 5 years**
Operating leases	$207,529	$84,315	$123,214	$0	$0
Total	$207,529	$84,315	$123,214	$0	$0

In addition to the contractual obligations requiring that we make fixed payments, in conjunction with our efforts to secure oil and gas prospects, financing and services, we have, from time to time, granted overriding royalty interests (ORRI) in various properties, and may grant ORRIs in the future, pursuant to which we will be obligated to pay a portion of our interest in revenues from various prospects to third parties.

Planned Drilling, Leasehold and Other Activities. As of December 31, 2009, our acquisition and drilling budget for 2010 totaled approximately $16.15 million and related principally to (1) drilling eight wells in Colombia on existing Hupecol prospects; (2) seismic work and drilling two wells on the Serrania Block operated by Shona Energy; (3) seismic work and preparation for drilling two wells on the CPO 4 Block operated by SK Energy; and (4) drilling one well on domestic prospects. Additional wells may be drilled at locations to be determined based on the results of the planned drilling projects. Our acquisition and drilling budget has historically been subject to substantial fluctuation over the course of a year based upon successes and failures in drilling and completion of prospects and the identification of additional prospects during the course of a year. In particular, we note that, in light of the sharp decline in commodity prices during the second half of 2008 and early 2009, we expanded our efforts to seek out favorable asset acquisition opportunities. Should we pursue any such opportunities, our acquisition and drilling budget could be materially altered.

Management presently anticipates that our total expenditures relating to exploration and development of the CPO 4 Bloc will be approximately $15.0 million running through 2011 and including $10.2 million budgeted during 2010. Management anticipates that our current financial resources combined with expected operating cash flows, will meet our anticipated objectives and business operations, including investments in the CPO 4 Block and other planned property acquisitions and drilling activities, for at least the next 12 months, without the need for additional capital. Management anticipates that available capital resources will be supplemented by the expected proceeds from the potential sale of a portion of the Hupecol properties, although there is no assurance as to whether such a sale will in fact take place or, if such a sale does occur, the timing of such a sale or the proceeds that may be realized from such a sale. Because the timing and actual costs and results associated with development of the Serrania Block and CPO 4 Block cannot be predicted with certainty and because we continually seek opportunities to acquire and develop reserves, it is possible that we may require and seek additional financing to support development of existing prospects or additional prospects that may be acquired in the future. We have no commitments to provide any additional financing should we require and seek such financing and there is no guarantee that we will be able to secure additional financing on acceptable terms, or at all, to support future acquisitions and development activities.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2009.

Inflation

We believe that inflation has not had a significant impact on our operations since inception.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for production depends on numerous factors beyond our control.

We have not historically entered into any hedges or other derivative commodity instruments or transactions designed to manage, or limit exposure to oil and gas price volatility.

Item 8. Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See "Index to Financial Statements" on page 43 of this report.

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

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation as of December 31, 2009 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2009.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as that term is defined in Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with generally accepted accounting principles ("GAAP"). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk. In addition, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

In order to evaluate the effectiveness of our internal control over financial reporting as of December 31, 2009, as required by Section 404 of the Sarbanes-Oxley Act of 2002, our management conducted an assessment, including testing, based on the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). A material weakness is a control deficiency, or a combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements will not be prevented or detected. Based on our assessment, management has concluded that our internal control over financial reporting at December 31, 2009 was effective.

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

Changes in Internal Control over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) occurred during the fourth quarter of fiscal 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Executive Officers

Our executive officers as of December 31, 2009, and their ages and positions as of that date, are as follows:

Name	Age	Position
John F. Terwilliger	62	President, Chief Executive Officer and Chairman
James J. Jacobs	32	Chief Financial Officer

John F. Terwilliger has served as our President, CEO and Chairman since our inception in April 2001.

James J. Jacobs has served as our Chief Financial Officer since July 2006. From April 2003 until joining the Company, Mr. Jacobs served as an Associate and as Vice President—Energy Investment Banking at Sanders Morris Harris, Inc., an investment banking firm, where he specialized in energy sector financing and transactions. Previously, Mr. Jacobs was an Energy Finance Analyst at Duke Capital Partners, LLC from June 2001 to April 2003 and a Tax Consultant at Deloitte & Touché, LLP. Mr. Jacobs holds a Masters of Professional Accounting from the University of Texas and is a Certified Public Accountant.

There are no family relationships among the executive officers and directors. Except as otherwise provided in employment agreements, each of the executive officers serves at the discretion of the Board.

Item 11. Executive Compensation

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Equity compensation plan information is set forth in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See "Index to Financial Statements" on page 43 of this report.
2. Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date	Number	Filed Herewith
3.1	Certificate of Incorporation of Houston American Energy Corp. filed April 2, 2001	SB-2	8/3/01	3.1	
3.2	Amended and Restated Bylaws of Houston American Energy Corp. adopted November 26, 2007	8-K	11/29/07	3.1	
3.3	Certificate of Amendment to the Certificate of Incorporation of Houston American Energy Corp. filed September 25, 2001	SB-2	10/01/01	3.4	
4.1	Text of Common Stock Certificate of Houston American Energy Corp.	SB-2	8/3/01	4.1	
10.1	Form of Registration Rights Agreement, dated May 4, 2005	8-K	5/10/05	4.3	
10.2	Houston American Energy Corp. 2005 Stock Option Plan*	8-K	8/16/05	10.1	
10.3	Form of Director Stock Option Agreement*	8-K	8/16/05	10.2	
10.4	Form of Placement Agent Warrant, dated April 28, 2006	8-K	4/28/06	4.1	
10.5	Form of Registration Rights Agreement, dated April 28, 2006	8-K	4/28/06	4.2	
10.6	Houston American Energy Corp. 2008 Equity Incentive Plan*	Sch 14A	4/28/08	Ex A	
10.7	Form of Restricted Stock Agreement with John Terwilliger and James J. Jacobs*	Sch 14A	4/28/08	Ex B	
10.8	Letter Agreement, dated February 3, 2009, between Houston American Energy Corp., Yazoo Pipeline Co., L.P., Sterling Exploration & Production Co., L.L.C., and Matagorda Operating Company.	8-K	2/05/09	10.1	
10.9	Form of Subscription Agreement, dated November 2009 relating to the sale of shares of common stock	8-K	12/03/09	10.1	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	3/26/04	14.1	
23.1	Consent of GBH CPAs, PC				X
23.2	Consent of Lonquist & Co., LLC				X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date	Number	Filed Herewith
31.1	Section 302 Certification of CEO				X
31.2	Section 302 Certification of CFO				X
32.1	Section 906 Certification of CEO				X
32.2	Section 906 Certification of CFO				X
99.1	Code of Business Ethics	8-K	7/7/06	99.1	
99.2	Report of Lonquist & Co., LLC				X

* Compensatory plan or arrangement.

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.

HOUSTON AMERICAN ENERGY CORP.

Dated: March 25, 2010

By: /s/ JOHN F. TERWILLIGER
John F. Terwilliger
President

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.

Signature	Title	Date
/s/ JOHN F. TERWILLIGER **John F. Terwilliger**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer)	March 25, 2010
/s/ O. LEE TAWES, III **O. Lee Tawes, III**	Director	March 25, 2010
/s/ EDWIN BROUN III **Edwin Broun III**	Director	March 25, 2010
/s/ STEPHEN HARTZELL **Stephen Hartzell**	Director	March 25, 2010
/s/ JOHN P. BOYLAN **John P. Boylan**	Director	March 25, 2010
/s/ JAMES J. JACOBS **James J. Jacobs**	Chief Financial Officer (Principal Accounting and Financial Officer)	March 25, 2010

HOUSTON AMERICAN ENERGY CORP.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Houston American Energy Corp.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Houston American Energy Corp. (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years ended December 31, 2009 and 2008. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes 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 Houston American Energy Corp. as of December 31, 2009 and 2008, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ GBH CPAs, PC
GBH CPAs, PC
www.gbhcpas.com
Houston, Texas

March 25, 2010

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash	$ 14,010,637	$ 9,910,694
Accounts receivable—Oil and gas sales	1,831,674	315,631
Escrow receivable	873,871	1,673,551
Note receivable	125,000	—
Prepaid expenses and other current assets	8,913	20,240
TOTAL CURRENT ASSETS	16,850,095	11,920,116
PROPERTY, PLANT AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	22,009,344	17,550,268
Costs not being amortized	5,599,245	2,064,566
Office equipment	11,878	11,878
Total	27,620,467	19,626,712
Accumulated depletion, depreciation, amortization, and impairment	(16,264,212)	(14,363,581)
PROPERTY, PLANT AND EQUIPMENT, NET	11,356,255	5,263,131
Deferred Tax Asset	5,680,026	5,277,354
Other Assets	176,453	176,453
TOTAL ASSETS	$ 34,062,829	$ 22,367,054
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 469,528	$ 1,363,827
Accrued expenses	14,949	9,264
Foreign income taxes payable	128	10,191
TOTAL CURRENT LIABILITIES	484,605	1,383,282
LONG-TERM LIABILITIES		
Reserve for plugging and abandonment costs	316,260	185,910
Deferred rent obligation	16,652	19,614
TOTAL LONG-TERM LIABILITIES	332,912	205,524
SHAREHOLDERS' EQUITY		
Preferred stock, par value $.001, 10,000,000 authorized, 0 shares outstanding	—	—
Common stock, par value $.001; 100,000,000 shares authorized, 30,890,772 and 28,000,772 shares outstanding	30,891	28,001
Additional paid-in capital	35,495,395	22,631,773
Accumulated deficit	(2,280,974)	(1,611,526)
TOTAL SHAREHOLDERS' EQUITY	33,245,312	21,048,248
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 34,062,829	$ 22,637,054

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

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

	2009	2008
Oil and gas revenue	$ 8,116,275	$10,622,050
EXPENSES OF OPERATIONS		
Lease operating expense and severance tax	4,746,295	3,366,740
Joint venture expense	172,890	183,510
Depreciation, depletion and amortization	1,900,631	5,816,691
Impairment of oil and gas properties	—	5,621,106
Gain on sale of oil and gas properties	—	(7,615,236)
General and administrative expense	2,768,195	3,152,930
Total expenses	9,588,011	10,525,741
Income (Loss) from operations	(1,471,736)	96,309
OTHER INCOME		
Interest income	64,882	295,375
Total other income	64,882	295,375
Net Income (loss) before taxes	(1,406,854)	391,684
Income tax benefit	(737,406)	(73,261)
Net income (loss)	$ (669,448)	$ 464,945
Basic net income (loss) per share	$ (0.02)	$ 0.02
Diluted net income (loss) per share	$ (0.02)	$ 0.02
Basic weighted average shares	28,214,553	27,992,808
Diluted weighted average shares	28,214,553	28,038,847

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

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
For the Years Ended December 31, 2009 and 2008

	Common Stock			Treasury Stock		Accumulated Equity	
	Shares	Amount	Paid-in Capital	Shares	Amount	(Deficit)	Total
Balance at December 31, 2007	27,920,172	$27,920	$22,377,832	(100,000)	$(85,834)	$(2,076,471)	$20,243,447
Retired treasury stock	(100,000)	(100)	(85,734)	100,000	85,834	—	—
Stock issued for -							
Employees	55,600	56	400,264	—	—	—	400,320
Warrant Exercise	125,000	125	374,875	—	—	—	375,000
Options issued to director	—	—	15,113	—	—	—	15,113
Options issued to employee	—	—	671,454	—	—	—	671,454
Dividends paid	—	—	(1,122,031)	—	—	—	(1,122,031)
Net Income	—	—	—	—	—	464,945	464,945
Balance at December 31, 2008	28,000,772	28,001	22,631,773	—	—	(1,611,526)	21,048,248
Stock issued for -							
Cash, net of offering costs of $758,760	2,890,000	2,890	12,763,550	—	—	—	12,766,440
Options issued to director	—	—	38,174	—	—	—	38,174
Options issued to employee	—	—	1,041,955	—	—	—	1,041,955
Dividends paid	—	—	(980,057)	—	—	—	(980,057)
Net loss	—	—	—	—	—	(669,448)	(669,448)
Balance at December 31, 2009	30,890,772	$30,891	$35,495,395	—	$ —	$(2,280,974)	$33,245,312

The accompanying notes are an integral part of these financial statements

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

	2009	2008
CASH FLOW FROM OPERATING ACTIVITIES		
Net income (loss)	$ (669,448)	$ 464,945
Adjustments to reconcile net income (loss) to net cash provided by operations		
Depreciation and depletion	1,900,631	5,816,691
Stock based compensation	1,080,129	1,086,887
Impairment of oil and gas properties	—	5,621,106
Deferred tax asset	(402,672)	(5,277,354)
Accretion of asset retirement obligation	13,038	17,501
Amortization of deferred rent	(2,962)	(592)
Gain on sale of oil and gas properties	—	(7,615,236)
Decrease (increase) in accounts receivable	(1,516,043)	278,716
Decrease (increase) in prepaid expense	11,327	12,191
(Decrease) increase in accounts payable and accrued liability	(898,677)	1,047,199
Net cash provided by (used in) operations	(484,677)	1,452,054
CASH FLOW FROM INVESTING ACTIVITIES		
Purchases of marketable securities	—	(3,000,000)
Sales of marketable securities	—	12,650,000
Issuance of note receivable	(125,000)	—
Acquisition of oil and gas properties and assets	(8,273,545)	(10,841,353)
Proceeds from sale of Colombian properties, net of expenses	—	9,878,797
Proceeds from sale of USA properties, net of expenses	397,102	273,696
Decrease (increase) in escrow receivable	799,680	(173,287)
Net cash provided by (used in) investing activities	(7,201,763)	8,787,853
CASH FLOW FROM FINANCING ACTIVITIES		
Sale of common stock	13,525,200	—
Common stock offering costs	(758,760)	
Exercise of warrants	—	375,000
Dividends paid	(980,057)	(1,122,031)
Net cash provided by (used in) financing activities	11,786,383	(747,031)
INCREASE IN CASH	4,099,943	9,492,876
Cash, beginning of year	9,910,694	417,818
Cash, end of year	$14,010,637	$ 9,910,694
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid	$ —	$ —
Taxes paid	$ 224,261	$ 5,200,306
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES		
Asset retirement obligation	$ 117,312	$ 99,981
Retired treasury stock	—	85,834
Cash proceeds from sale of oil and gas properties escrowed	—	1,673,551

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

NOTE 1—NATURE OF COMPANY AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Houston American Energy Corp. (a Delaware Corporation) ("the Company" or "HUSA") was incorporated on April 2, 2001. The Company is engaged, as a non-operating joint owner, in the exploration, development, and production of natural gas, crude oil, and condensate from properties located principally in the Gulf Coast area of the United States and international locations with proven production, which to date has focused on Colombia, South America.

Consolidation

The accompanying consolidated financial statements include all accounts of HUSA and its subsidiaries (HAEC Louisiana E&P, Inc. and HAEC Caddo Lake E&P, Inc.). All significant inter-company balances and transactions have been eliminated in consolidation.

General Principles and Use of Estimates

The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including those related to such potential matters as litigation, environmental liabilities, income taxes, determination of proved reserves of oil and gas and asset retirement obligations. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Reclassification

Certain amounts for prior periods have been reclassified to conform to the current presentation.

Oil and Gas Revenues

The Company recognizes sales revenues, net of royalties and net profits interests, based on the amount of gas, oil and condensate sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when production has been delivered to a pipeline. The Company follows the sales method to account for natural gas imbalances. Sales may result in more or less than the Company's share of pro-rata production from certain wells. When natural gas sales volumes exceed the Company's entitled share and the accumulated overproduced balance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company will record a liability. Historically, sales volumes have not materially differed from the Company's entitled share of natural gas production and the Company did not have a material imbalance position in terms of volumes or values at December 31, 2009 or 2008.

Oil and Gas Properties

The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. Capitalized costs include lease acquisition, geological and geophysical work, delay rentals, costs of drilling, completing and equipping the wells and any internal costs that are directly related to acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Proceeds from the sale or other disposition of oil and gas properties are generally treated as a reduction in the capitalized costs of oil and gas properties, unless the impact of such a reduction would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The Company categorizes its full costs pools as costs subject to amortization and costs not being amortized. The sum of net capitalized costs subject to amortization, including estimated future development and abandonment costs, are amortized using the unit-of-production method. Depletion and amortization for oil and gas properties was $1,900,631 and $5,816,691 at December 31, 2009 and 2008, respectively and accumulated amortization, depreciation and impairment was $16,264,212 and $14,363,581 at December 31, 2009 and 2008, respectively.

Costs Excluded

Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties. The Company excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the costs subject to amortization.

Ceiling Test

Under the full cost method of accounting, a ceiling test is performed each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X. The ceiling test determines a limit, on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment (*"DD&A"*) and the related deferred income taxes, may not exceed the estimated future net cash flows from proved oil and gas reserves, calculated for 2009 using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) with consideration of price change only to the extent provided by contractual arrangement, discounted at 10%, net of related tax effects. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A.

Unevaluated oil and gas properties not subject to amortization at December 31, 2009 included the following:

	North America	South America	Total
Leasehold acquisition costs	$ 814,766	$2,596,889	$3,411,655
Geological, geophysical, screening and evaluation costs	1,702,533	437,763	2,140,296
Leasehold retention costs	47,294	—	47,294
Total	$2,564,593	$2,993,732	$5,599,245

Unevaluated oil and gas properties not subject to amortization at December 31, 2008 included the following:

	North America	South America	Total
Leasehold acquisition costs	$ 221,253	$ —	$ 221,253
Geological, geophysical, screening and evaluation costs	1,379,692	435,431	1,815,123
Leasehold retention costs	28,191	—	28,191
Total	$1,629,136	$435,431	$2,064,567

Furniture and Equipment

Office equipment is stated at original cost and is depreciated on the straight-line basis over the useful life of the assets, which ranges from three to five years.

Depreciation expense for office equipment was $0 and $0 at December 31, 2009 and 2008, respectively, and office equipment was fully depreciated at December 31, 2009.

Asset Retirement Obligations

The Company has adopted Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 410, *Asset Retirement and Environmental Obligations* ("ASC 410"), which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For the Company, asset retirement obligations ("ARO") represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. Although the Company's domestic policy with respect to ARO is to assign depleted wells to a salvager for the assumption of abandonment obligations before the wells have reached their economic limits, as required under ASC 410, the Company has estimated its future ARO obligation with respect to its domestic operations. With the adoption of ASC 410, the ARO assets, which are carried on the balance sheet as part of the full cost pool, have been included in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability have been included in the computation of the discounted present value of estimated future net revenues.

The following table describes changes in our asset retirement liability during each of the years ended December 31, 2009 and 2008. The ARO liability in the table below includes amounts classified as both current and long-term at December 31, 2009 and 2008.

	North America Years Ended December 31		South America Years Ended December 31	
	2009	2008	2009	2008
ARO liability at January 1	$ 9,479	$ 24,038	$176,431	$ 91,023
Accretion expense	882	1,659	12,156	15,842
Liabilities incurred from drilling	15,241	—	91,727	152,326
Liabilities settled—assets sold	—	—	—	(46,633)
Changes in estimates	(1,096)	(16,218)	11,440	(36,127)
ARO liability at December 31,	$24,506	$ 9,479	$291,754	$176,431

Joint Venture Expense

Joint venture expense reflects the indirect field operating and regional administrative expenses billed by the operator of the Colombian concessions.

Income Taxes

Deferred income taxes are provided on a liability method whereby deferred tax assets and liabilities are established for the difference between the financial reporting and income tax basis of assets and liabilities as well as operating loss and tax credit carry forwards. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. At December 31, 2009, the Company recognized a deferred tax asset of $5,680,026.

Preferred Stock

The Company has authorized 10,000,000 shares of preferred stock with a par value of $.001. The Board of Directors shall determine the designations, rights, preferences, privileges and voting rights of the preferred stock as well as any restrictions and qualifications thereon. No shares of preferred stock have been issued.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and cash investments with initial maturity dates of less than three months.

Net Income (Loss) Per Share

Pursuant to FASB ASC Topic 260, *Earnings Per Share*, basic net income (loss) per share is computed by dividing the net income (loss) attributable to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted net income (loss) per share is computed by dividing the net income (loss) attributable to common shareholders by the weighted-average number of common and common equivalent shares outstanding during the period. Common share equivalents included in the diluted computation represent shares issuable upon assumed exercise of stock options and warrants using the treasury stock and "if converted" method. For periods in which net losses are incurred, weighted average shares outstanding is the same for basic and diluted loss per share calculations, as the inclusion of common share equivalents would have an anti-dilutive effect.

For the year ended December 31, 2009, 1,538,998 options and 190,000 warrants to purchase common stock were excluded from the calculation of diluted net loss per share because they were anti-dilutive. For the year ended December 31, 2008, 1,392,333 options and 190,000 warrants to purchase common stock resulted in weighted average diluted shares outstanding of 28,038,847 based upon the treasury method, which resulted in $0.02 diluted earnings per share.

Concentration of Risk

The Company is dependent upon the industry skills and contacts of John F. Terwilliger and James J. Jacobs, the chief executive officer and chief financial officer, respectively, to identify potential acquisition targets in the onshore coastal Gulf of Mexico region of Texas and Louisiana and in the South American country of Colombia. Further, as a non-operator oil and gas exploration and production company, and through its interest in a limited liability company ("Hupecol") and concessions operated by Hupecol, Shona Energy and by SK Energy in the South American country of Colombia, the Company is dependent on the personnel, management and resources of Hupecol, Shona Energy and SK Energy to operate efficiently and effectively.

As a non-operating joint interest owner, the Company has a right of investment refusal on specific projects and the right to examine and contest its division of costs and revenues determined by the operator.

The Company currently has interests in concessions in Colombia and expects to be active in Colombia for the foreseeable future. The political climate in Colombia is unstable and could be subject to radical change over a very short period of time. In the event of a significant negative change in political and economic stability in the vicinity of the Company's Colombian operations, the Company may be forced to abandon or suspend their efforts. Either of such events could be harmful to the Company's expected business prospects.

At December 31, 2009, 77.8% of the Company's net oil and gas property investment and 97.8% of its revenue was with or derived from Hupecol.

99.1% of the oil production for 2009 from the Company's mineral interests was sold to an international integrated oil company. The gas production is sold to U.S. natural gas marketing companies based on the highest bid. There were no other product sales of more than 10% to a single buyer.

The Company reviews accounts receivable balances when circumstances indicate a balance may not be collectible. Historically, the Company has not experienced any uncollectible accounts receivable. Based upon the Company's review, no allowance for uncollectible accounts was deemed necessary at December 31, 2009 and 2008, respectively.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash and cash equivalents. The Company had cash deposits of approximately $13,673,326 in excess of the FDIC's current insured limit of $250,000 at December 31, 2009. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Stock-Based Compensation

The Company measures the cost of employee services received in exchange for stock and stock options based on the grant date fair value of the awards under FASB ASC Topic 718, *Compensation – Stock Compensation* ("ASC 718"). The Company determines the fair value of stock option grants using the Black-Scholes option pricing model. The Company determines the fair value of shares of nonvested stock (also commonly referred to as restricted stock) based on the last quoted price of our stock on the date of the share grant. The fair value determined represents the cost for the award and is recognized over the vesting period during which an employee is required to provide service in exchange for the award. As share-based compensation expense is recognized based on awards ultimately expected to vest, the Company reduces the expense for estimated forfeitures based on historical forfeiture rates. Previously recognized compensation costs may be adjusted to reflect the actual forfeiture rate for the entire award at the end of the vesting period. Excess tax benefits, as defined in ASC 718, if any, are recognized as an addition to paid-in capital.

Recent Accounting Developments

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* ("SFAS 168" or ASC 105-10). SFAS 168 (ASC 105-10) establishes the Codification as the sole source of authoritative accounting principles recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. SFAS 168 (ASC 105-10) was prospectively effective for financial statements issued for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of SFAS 168 (ASC 105-10) on July 1, 2009 did not impact the Company's results of operations or financial condition. The Codification did not change GAAP; however, it did change the way GAAP is organized and presented. As a result, these changes impact how companies reference GAAP in their financial statements and in their significant accounting policies. The Company implemented the Codification in this Report by providing references to the Codification topics alongside references to the corresponding standards.

In June 2008, the FASB issued FSP EITF 03-6-1 (ASC 260-10), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1" or ASC 260-10). FSP EITF 03-6-1 (ASC 260-10) addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in computing earnings per share under the two-class method described in SFAS No. 128 (ASC 260-10), *Earnings Per Share*. FSP EITF 03-6-1(ASC 260-10) is effective for the Company as of January 1, 2009 and in accordance with its requirements it will be applied retrospectively. The adoption of FSP EITF 03-6-1 (ASC 260-10) did not have a material impact on the Company's consolidated financial statements.

On December 31, 2008, the Securities and Exchange Commission ("SEC") published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. In October 2009, the SEC issued Staff Accounting Bulletin No. 113 (SAB No. 113), effective November 4, 2009, revising Staff Accounting Bulletin Series Topic 12 *Oil and Gas Producing Activities* primarily to conform Topic 12 to the aforementioned SEC updates to its oil and gas reporting requirements. Key changes to the SEC's rules and interpretations include a requirement to use 12-month average pricing rather than year-end pricing for estimating proved reserves, the ability to include nontraditional resources in reserves, the ability to use new technology for determining proved reserves, and permitting disclosure (outside of the financial statements) of probable and possible reserves. The full-cost accounting method, which the Company follows, is changed to no longer allow the option of ceiling test impairments being reduced or eliminated by consideration of oil and gas price increases occurring subsequent to the impairment date. The FASB aligned ASC Topic 932, with the aforementioned SEC requirements by issuing ASC Update 2010-03. The new SEC and FASB authoritative guidance became effective for the Company's 2009 Annual Report on Form 10-K and has been prospectively adopted as of December 31, 2009. The new authoritative guidance did not have a material impact on the Company's consolidated financial statements.

NOTE 2—RELATED PARTIES

In conjunction with the Company's efforts to secure oil and gas prospects, financing and services, in lieu of salary or other forms of compensation, during 2005, the Company granted to John F. Terwilliger, Chief Executive Officer, and Orrie L. Tawes, a principal shareholder and Director, overriding royalty interests in select mineral properties of the Company. During 2009 and 2008, Mr. Terwilliger received royalty payments relating to those properties totaling $114,135 and $141,883, respectively, and Mr. Tawes received royalty payments relating to those properties totaling $113,532 and $139,935, respectively.

NOTE 3—INCOME TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the period ending December 31, 2009 and 2008.

	2009	2008
Income (Loss) before income taxes	$(1,406,854)	$ 391,684
Income tax (benefit) computed at statutory rates	$ (478,330)	$ 133,173
Permanent differences, nondeductible expenses	2,789	2,960
Current Colombian tax expense	—	5,200,306
Increase (decrease) in valuation allowance	(220,939)	(284,561)
Return to Accrual Items	—	99,330
Foreign Tax Credit	—	(5,201,387)
State (net of federal benefit)	(40,926)	(23,082)
Tax provision (benefit)	$ (737,406)	$ (73,261)
Total Provision (benefit)		
Current State	$ —	$ 3,787
Deferred Federal	(361,737)	(5,251,772)
Deferred State	(40,926)	(25,582)
Foreign	(334,743)	5,200,306
Total provision (benefit)	$ (737,406)	$ (73,261)

At December 31, 2009 the Company has U.S. Federal tax loss carry forwards of $705,994 which will expire in 2029.The Company has a state net operating loss carry forward of $1,681,178 which will expire in various amounts beginning in 2027. The Company also has $1,684,745 of foreign tax credit carry forwards which will expire in various amounts beginning in 2015.

Management believes it is more likely than not that it will realize the benefit of its net deferred tax assets except for the foreign tax credit carry forward. No valuation allowance is placed on the portion of the foreign tax credit that the tax payer can elect to take as a deduction on future tax returns. A valuation allowance has been established on the remaining foreign tax credit carryover.

The tax effects of the temporary differences between financial statement income and taxable income are recognized as a deferred tax asset and liabilities. Significant components of the deferred tax asset and liability as of December 31, 2009 and 2008 are set out below.

	2009	2008
Non-Current Deferred tax assets:		
Net operating loss carryforwards	$ 240,038	$ —
Foreign tax credit carryforwards	1,684,745	2,019,488
Asset retirement obligation	17,781	13,197
Deferred State Tax	66,507	25,582
Stock Compensation	714,647	347,403
Book in excess of tax depreciation, depletion, and capitalization methods on oil and gas properties	3,579,549	3,715,865
Other	315,067	315,065
Colombia Future Tax Obligations	173,616	173,616
Total Non-Current Deferred tax assets	6,791,949	6,610,216
Non-Current Deferred tax liabilities:		
Total Non-Current tax liabilities	—	—
Valuation Allowance	(1,111,923)	(1,332,862)
Net deferred tax asset	$ 5,680,026	$ 5,277,354

Foreign Income Taxes

The Company owns an interest in various limited liability companies that operate and have activities in Colombia, through various entities controlled by Hupecol. Additionally, the Company owns an interest in properties located in Colombia and operated by SK Energy. Colombia's current tax rate is 33%. Based on information provided by the manager of Hupecol, the Company has determined its share of the Colombia tax liability relating to the entities operated by Hupecol for 2009 will be $234,869. This amount has been accrued during the year and will be funded by withholdings from the 2009 revenue and from revenue received in 2010. The Company has determined that it has no Colombian tax liability relating to the operations of SK Energy during 2009.

NOTE 4—STOCK BASED COMPENSATION

On August 12, 2005, the Company's Board of Directors adopted the Houston American Energy Corp. 2005 Stock Option Plan (the "2005 Plan"). The terms of the 2005 Plan allow for the issuance of up to 500,000 options to purchase 500,000 shares of the Company's common stock.

In 2008, the Company's Board of Directors adopted the Houston American Energy Corp. 2008 Equity Incentive Plan (the "2008 Plan" and, together with the 2005 Plan, the "Plans"). The terms of the 2008 Plan allow for the issuance of up to 2,200,000 shares of the Company's common stock pursuant to the grant of stock options and restricted stock. Persons eligible to participate in the Plans are key employees, consultants and directors of the Company.

During 2008, the Company granted 3,333 options to the members of the Board of Directors, 1,050,000 options and 55,600 shares of restricted stock to employees. Additionally, 200,000 previously granted options were vested at December 31, 2008. During 2009, the Company granted 26,665 options to members of the Board of Directors and 120,000 options to employees.

The options granted to the directors during 2008 vested immediately, had a ten year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions, risk-free interest rate 3.875%, expected life in years 5.0, expected stock volatility 73.81754%, and expected dividend yield of 0.0%. The Company determined the options qualify as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life. Using this model yielded a value of $15,113 which was charged to expense in 2008.

The options granted to employees during 2008 had a ten year life and 150,000 of the options vest ratably over three years and 900,000 of the options vest ratably over six years. The options were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions, risk-free interest rate 3.875%, expected life in years of 6 and 6.75, respectively, expected stock volatility 73.81754%, and expected dividend yield of 0.0%. The Company determined the options qualify as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life. The total value of the options was $5,299,214. The options are being expensed over the vesting period. During 2009 and 2008, $1,007,558 and $586,361, respectively, was amortized to expense as employee compensation for the options granted to employees during 2008.

The options granted to the directors during 2009 vested immediately, had a ten year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions, risk-free interest rate 3.19%, expected life in years 5, expected stock volatility 87.625%, expected future dividend yield of 0.0%. The Company determined the options qualify as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life. Using this model yielded a value of $38,174 which was charged to expense in 2009 for the options granted to directors during 2009.

The options granted to employees during 2009 vest ratably over three years, had a ten year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions, risk-free interest rate 3.19%, expected life in years 6, expected stock volatility 87.625%, and expected future dividend yield of 0.0%. The Company determined the options qualify as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life. The total value of the options was $182,831. The options are being expensed over the vesting period. During 2009, $34,396 was amortized to expense as employee compensation for the options granted to employees during 2009.

Option activity during 2009 and 2008 is as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2007	339,000	$3.12		
Granted	1,053,333	$7.20		
Exercised	—			
Forfeited	—			
Outstanding at December 31, 2008	1,392,333	$6.21		
Granted	146,665	$2.05		
Exercised	—			
Forfeited	—			
Outstanding at December 31, 2009	1,538,998	$5.81	8.06	$1,633,833

During 2009, a total of 200,000 options, with a weighted average grant date fair value of $5.05 per share, vested in accordance with the underlying agreements, and 26,665 options, with a weighted average grant date fair value of $1.43 per share, were granted which vested immediately. Unvested options at December 31, 2009 totaled 970,000, with a weighted average grant date fair value and exercise price of $4.67 and $6.56, respectively, an amortization period of 4.07 years and a weighted average remaining life of 8.55 years.

As of December 31, 2009, total unrecognized stock-based compensation expense related to non-vested stock options was $3,846,769. As of December 31, 2009 there were 1,161,002 shares of common stock available for issuance pursuant to future stock or option grants under the Plans.

During 2008, the Company's shareholders approved and the Company granted 55,600 shares of restricted common stock with immediate vesting to the Company's two principal officers. The Company recognized compensation expense of $400,320 based upon the stock price at the grant date attributable to these grants, which were originally approved, subject to stockholder approval, in 2007 by the Company's Board of Directors and then later approved by the Company's stockholders and issued in June 2008.

The following table reflects share-based compensation recorded by the Company for 2009 and 2008:

	2009	2008
Share-based compensation expense included in general and administrative expense	$1,080,128	$1,086,887
Earnings per share effect of share-based compensation expense	$ (0.04)	$ (0.04)

NOTE 5—COMMON STOCK

2009 Registered Direct Offering

In December 2009, the Company sold to various institutional investors, in a "registered direct" offering, an aggregate of 2,890,000 shares of common stock for net proceeds after offering costs of approximately $12,800,000.

Exercise of Warrants

During 2008, the placement agent of a 2005 private placement exercised 125,000 Placement Agent Warrants, and was issued 125,000 shares for an aggregate consideration of $375,000. At December 31, 2009, the Company had remaining 190,000 warrants outstanding with and exercise price of $3.00 per share and a remaining contractual life of 1.33 years.

At December 31, 2009, based upon the closing price of the Company's common stock, the outstanding warrants had an intrinsic value of $600,400.

Dividends

During 2009 and 2008, we declared and paid cash dividends to our shareholders of $0.035 and $0.04 per share, or an aggregate of $980,057 and $1,122,031, respectively.

NOTE 6—COMMITMENTS AND CONTINGENCIES

Lease Commitment

The Company leases office facilities under an operating lease agreement that expires May 31, 2012. The lease agreement requires future payments as follows:

Year	Amount
2010	$ 84,315
2011	86,684
2012	36,530
Thereafter	—
Total	$207,529

Total rental expense was $99,388 in 2009 and $74,455 in 2008. The Company does not have any capital leases or other operating lease commitments.

Standby Letter of Credit – CPO 4 Block

On November 5, 2009 JP Morgan Chase issued a Letter of Credit to Banco de Bogota S.A. for $2,037,500. Banco de Bogota then in turn issued a stand by letter of credit to the Agency De National Hydrocarbons to guaranty Houston American Energy's compliance and proper execution of the work obligations relating of the phase one (1) work program of the CPO-4 block for Houston American Energy's 25% interest in the Block. Per the Standby Letter of Credit issued between JP Morgan Chase and Banco de Bogota, Houston American Energy is required to keep on deposit with JP Morgan Chase $2,037,500. In addition, Houston American Energy was required by JP Morgan Chase to pay fees associated with the Standby Letter of Credit equal to 1.0% of the amount, or $20,375. The Standby Letter of credit expires on December 24, 2010.

Possible Hupecol Transaction

On September 21, 2009, management of the Company was advised that Hupecol had retained Scotia Waterous for purposes of evaluating a possible transaction (a "Transaction") involving the monetization of five exploration and production contracts covering approximately 413,000 acres comprising the Leona Block, La Cuerva Block, Dorotea Block, Las Garzas Block and Cabiona Block in Colombia. The Transaction may involve the sale of some or all of the assets and operations of the subject properties, an exchange or trade of assets, or other similar transaction and may be effected in a single transaction or a series of transactions.

Scotia Waterous has established a process whereby interested parties may evaluate a potential Transaction with the objective of completing one or more Transactions and has established a due date for proposals of April 6, 2010.

The Company is an investor in Hupecol and the Company's interest in the assets and operations of Hupecol that would be included in any Transaction represent a substantial portion of the Company's assets and operations in Colombia and are the principal revenue producing assets and operations of the Company. The Company's management intends to closely monitor the nature and progress of the Transaction in order to protect the interests of the Company and its shareholders. However, the Company has no effective ability to alter or prevent a Transaction and is unable to predict whether or not a Transaction will in fact occur or the nature or timing of any such Transaction. Further, the Company is unable to estimate the actual value that it might derive from any such Transaction and whether any such Transaction will ultimately be beneficial to the Company and its shareholders.

Legal Contingencies

The Company is subject to legal proceedings, claims and liabilities that arise in the ordinary course of its business. The Company accrues for losses associated with legal claims when such losses are probable and can be reasonably estimated. These accruals are adjusted as further information develops or circumstances change. The Company is currently not a party to any litigation.

Environmental Contingencies

The Company's oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Company to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition as well as the industry in general. Under these environmental laws and regulations, the Company could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether the Company was responsible for the release or if its operations were standard in the industry at the time they were performed. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks

Development Commitments

During the ordinary course of oil and gas prospect development, the Company commits to a proportionate share for the cost of acquiring mineral interest, drilling exploratory or development wells and acquiring seismic and geological information.

Employment Arrangements

The Company has no employment agreements with any of its officers or employees. The Company pays salary, bonuses and other compensation to its officers based on the determination of its compensation committee which periodically utilizes the services of compensation consultants.

For both 2009 and 2008, the compensation committee fixed the salary of the Company's Chief Executive Officer at $315,000. Salary of the Company's Chief Financial Officer was increased from $150,000 annually to $165,000 annually, effective July 1, 2008.

During 2008, the Compensation Committee awarded discretionary one-time cash bonuses to the Company's Chief Executive Officer and Chief Financial Officer, in the amounts of $675,000 and $75,000, respectively.

NOTE 7—NOTES RECEIVABLE

Yazoo DIP Financing

On February 4, 2009, the Company entered into a letter agreement (the "Letter Agreement") with Yazoo Pipeline Co., L.P., Sterling Exploration & Production Co., L.L.C., and Matagorda Operating Company (together, the "Debtors"), pursuant to which the Company agreed to provide debtor-in-possession financing ("DIP Financing") to the Debtors subject to approval of the Letter Agreement by the U.S. Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). On February 4, 2009, the Bankruptcy Court entered an order approving the DIP Financing on the terms set out in the Letter Agreement.

Under the terms of the Letter Agreement, the Company advanced a total of $115,724 to the Debtors. Advances incurred interest at 10% per annum and were to be repaid in full ninety (90) days from approval of the DIP Financing by the Bankruptcy Court, or the earlier consummation of a sale of the principal assets of the Debtors to the Company.

Pursuant to its rights under the Letter Agreement, after conducting due diligence with respect to the Debtors, the Company elected to terminate negotiations with the Debtors with respect to the potential acquisition of the assets of the Debtors. On April 10, 2009, the Debtors repaid the DIP Financing in full in the amount of $117,897, including principal and interest, and at December 31, 2009, no amounts were owed to the Company relative to the DIP Financing.

West Klondike Advances

During 2009, the Company advanced funds towards the West Klondike prospect in Louisiana, but subsequently elected not to proceed with the project. On December 30, 2009, the operator of the West Klondike prospect delivered to the Company a promissory note in the amount of $125,000 representing the obligation of the operator to refund the amount advanced with respect to the prospect. The note has a due date of May 1, 2010 and no stated interest rate. The Company fully expects to realize the amount owed under the note, and has not booked a reserve against its repayment.

NOTE 8—OIL AND GAS ACQUISITIONS

Domestic Leases

During 2009, the Company acquired interests in four prospects in Louisiana, the N. Jade and W. Jade prospects, acquired for $67,480, and the Profit Island and North Profit Island prospects, acquired for $350,644. Subsequent to purchasing its interest in the Profit and North Profit Island prospects, the Company sold down part of its interest in the Profit Island prospect. The Company still retains an interest in both of the prospects.

During 2009, the Company acquired (1) a 2.5% working interest in over 4,500 acres under lease within a 50,000 acre area of mutual interest (AMI) in Karnes County, Texas, for a purchase price of $75,000, and (2) a 1.25% Overriding Royalty in the same leases and all acreage within the AMI, for a purchase price of $100,000. Per the contract, the Company will be carried to the completion point on the first well.

Colombian Leases

Serrania Contract Farmout

During 2009, the Company entered into a farmout agreement with Shona Energy Limited pursuant to which the Company will pay 25.0% of designated Phase 1 geological and seismic costs in return for a 12.5% interest in the Serrania Contract for Exploration and Production covering the approximately 110,769 acre Serrania Block in Colombia.

Los Picachos TEA

During 2009, the Company elected to participate at its percentage interest (12.5%) in the Los Picachos Technical Evaluation Agreement (the "TEA").

The TEA was entered into on August 26, 2009 by and between the Colombian National Hydrocarbons Agency and Hupecol Operating Co. LLC and encompasses an 86,235 acre region located to the west and northwest of the Serrania block, which is located in the municipalities of Uribe and La Macarena in the Department of Meta in the Republic of Colombia.

As a result of the election to participate, the Company agreed to pay its proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the TEA.

CPO 4 Farmout

During 2009, the Company announced the approval by the National Hydrocarbon Agency in Colombia ("ANH") of a Farmout Agreement and Joint Operating Agreement with SK Energy Co. LTD., a Korean multinational conglomerate ("SK"), relating to the CPO 4 Contract for Exploration and Production (the "CPO 4 Contract") covering the 345,452 net acre CPO 4 Block located in the Western Llanos Basin in the Republic of Colombia.

Under the Joint Operating Agreement, effective retroactive to May 31, 2009, SK will act as operator of the CPO 4 Block and the Company will pay 25.0% of all past and future cost related to the CPO 4 block, as well as an additional 12.5% of the Seismic Acquisition Costs incurred during the Phase 1 Work Program, for which the Company will receive a 25.0% interest in the CPO 4 Block. The Company's share of the past costs incurred was $194,584.

The Phase 1 Work Program consists of reprocessing approximately 400 kilometers of existing 2-D seismic data, the acquisition, processing and interpretation of a 2-D seismic program containing approximately 620 kilometers of data and the drilling of two exploration wells. The Phase 1 Work Program is estimated to be completed by June 1, 2011. The Company's costs for the entire Phase 1 Work Program are estimated to total approximately $15,000,000.

NOTE 9—SALE OF OIL AND GAS PROPERTIES

Sale of Caracara Assets

In June 2008, the Company, through Hupecol Caracara LLC as owner/operator under the Caracara Association Contract, sold all of its interest in the Caracara Association Contract and related assets for a total cash consideration of $11,917,418. At December 31, 2007, the estimated proved reserves associated with these assets totaled 787,742 barrels of oil, which represented 60.37% of our estimated proved oil and natural gas reserves. Sales of oil and gas properties under the full cost method of accounting are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and reserves. Since the sale of these oil and gas properties would significantly alter the relationship, we recognized a gain on the sale of $7,615,236 during the year ended December 31, 2008, computed as follows:

Proceeds from the sale	$11,917,418
Add: Transfer of asset retirement and other obligations	46,633
Less: Transaction costs	(370,908)
Carrying value of oil and gas properties	(3,977,907)
Carrying value of other assets	—
Net gain on sale	$ 7,615,236

The carrying value of the properties sold was computed by allocating total capitalized costs within the non-U.S. full cost pool between properties sold and properties retained based upon the ratio of proved reserves sold and those proved reserves retained to total estimated proved reserves prior to the sale.

The following table presents pro forma data that reflects revenue, income from continuing operations, net income and income per share for 2008 as if the Caracara transaction had occurred at the beginning of the period and excludes the related gain on sale.

	2008
Pro-Forma Information	
Oil and gas revenue	$ 7,616,910
Loss from operations	(9,748,235)
Net income (loss)	$(4,436,584)
Basic loss per share	$ (0.16)
Diluted loss per share	$ (0.16)

Pursuant to the terms of the sale of the Caracara assets, on the closing date of the sale, a portion of the purchase price was deposited in escrow to settle post-closing adjustments under the purchase and sale agreement. The Company's proportionate interest in the escrow deposit totaled $1,673,551, and was recorded as Escrow receivable. On June 17, 2009, $1,158,613 of the funds deposited in escrow was released to the Company based on post-closing adjustments. At December 31, 2009, the balance of the funds held in escrow, including $514,938 representing the Company's proportionate interest in the escrow deposit, continued to be held in escrow pending resolution of disputes among Hupecol, the purchaser of the Caracara assets and Ecopetrol.

Colombian taxes attributable to the sale of the Caracara assets, totaling $4,394,575, were recorded and paid at the time of closing.

Sale of Domestic Leasehold Interests

During 2009, the Company received $353,896 from the sale of part of its interest in the Profit Island prospect. The proceeds received were recorded as a reduction of oil and gas properties. The Company still retains an interest in both of the prospects. See "Note 8 – Oil and Gas Acquisitions – Domestic Leases."

NOTE 10—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the twelve months ended December 31, 2009 and 2008 and Long Lived Assets as of December 31, 2009 and 2008 attributable to each geographical area are presented below:

	Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Long Lived Assets, Net	Revenues	Long Lived Assets, Net
North America	$ 171,922	$ 2,730,667	$ 410,471	$1,708,617
South America	7,944,353	8,625,588	10,211,579	3,554,514
Total	$8,116,275	$11,356,255	$10,622,050	$5,263,131

NOTE 11—SUBSEQUENT EVENTS

Oil and Gas Acquisition

On February 25, 2010, the Company elected to participate for its percentage interest (12.5%) in the Macaya Technical Evaluation Agreement (the "TEA").

The TEA was entered into in February 2010 by and between the Colombian National Hydrocarbons Agency ("ANH") and Hupecol and encompasses a 195,171 acre region located to the southeast of the Serrania block, which is located in the municipalities of Uribe and La Macarena in the Department of Meta in the Republic of Colombia.

As a result of the election to participate, the Company agreed to pay its proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the TEA.

Warrant Exercises

On January 4 and 26 and February 16· 2010, the placement agent of a 2005 private placement exercised 95,000, 47,500 and 47,500 Placement Agent Warrants (total 190,000 warrants), respectively, and was issued a total of 190,000 shares of common stock for an aggregate consideration of $570,000.

Dividend

In February 2010, the Company's board of directors declared a dividend of $0.005 per share with a record date of March 1 and a payment date of March 17.

Other Subsequent Events

The Company evaluated subsequent events through March 25, 2010, which is the date the financial statements were issued and there were no other significant events to report.

NOTE 12—SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

This footnote provides unaudited information required by FASB ASC Topic 932, *Extractive Activities—Oil and Gas*.

Geographical Data

The following table shows the Company's oil and gas revenues and lease operating expenses, which excludes the joint venture expenses incurred in South America, by geographic area:

	2009	2008
Revenues		
United States	$ 171,922	$ 410,471
South America	7,944,353	10,211,579
	$8,116,275	$10,622,050
Production Cost		
United States	$ 80,717	$ 134,527
South America	4,665,578	3,232,213
	$4,746,295	$ 3,366,740

Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2009, all of which are onshore properties located in the United States and Colombia, South America are summarized below:

	United States	South America	Total
Unproved properties not being amortized	$ 2,564,594	$ 3,034,651	$ 5,599,245
Proved properties being amortized	3,554,717	18,454,627	22,009,344
Accumulated depreciation, depletion, amortization and valuation allowances	(3,388,644)	(12,863,690)	(16,252,334)
Net capitalized costs	$ 2,730,667	$ 8,625,588	$ 11,356,255

During 2008, the Company recorded a provision for impairments of $5,621,106, of which $467,209 were attributable to the United States properties and $5,153,897 were attributable to South American properties.

Amortization Rate

The amortization rate per unit based on barrel equivalents was $11.38 for the United States and $14.28 for South America.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2009 and 2008 are summarized below:

	2009	
	United States	South America
Property acquisition costs:		
Proved	$ 106,875	$ —
Unproved	1,010,941	2,560,808
Exploration costs	335,070	2,505,497
Development	—	1,754,354
Total costs incurred	$1,452,886	$6,820,659

	2008	
	United States	South America
Property acquisition costs:		
Proved	$ —	$ —
Unproved	230,089	
Exploration costs	698,738	5,520,901
Development costs	—	4,391,625
Total costs incurred	$ 928,827	$9,912,526

Reserve Information and Related Standardized Measure of Discounted Future Net Cash Flows

In December 2009, the Company adopted revised oil and gas reserve estimation and disclosure requirements. The primary impact of the new disclosures is to conform the definition of proved reserves with the SEC Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. The accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economical to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technology to estimate proved oil and gas reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. The unaudited supplemental information on oil and gas exploration and production activities for 2009 has been presented in accordance with the new reserve estimation and disclosure rules, which may not be applied retrospectively. The 2008 data is presented in accordance with FASB oil and gas disclosure requirements effective during those periods. Disclosures by geographic area include the United States and South America, which consists of our interests in Colombia. The effect of applying the 12-month average price, versus the 2009 year-end price, decreased the net remaining reserve volumes by 10.65% of total proved reserves. The standardized measure of discounted future net cash flows for 2009 decreased by $17.04 million as a result of using the 12-month average price rather than the year-end 2009 price.

The supplemental unaudited presentation of proved reserve quantities and related standardized measure of discounted future net cash flows provides estimates only and does not purport to reflect realizable values or fair market values of the Company's reserves. Volumes reported for proved reserves are based on reasonable estimates. These estimates are consistent with current knowledge of the characteristics and production history of the reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, significant changes to these estimates can be expected as future information becomes available.

Proved reserves are those estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The reserve estimates set forth below were prepared by Lonquist & Co., LLC (Lonquist), utilizing reserve definitions and pricing requirements prescribed by the SEC. Lonquist is an independent professional engineering firm specializing in the technical and financial evaluation of oil and gas assets. Lonquist's report was conducted under the direction of Don E. Charbula, P.E., Vice President of Lonquist & Co. Mr. Charbula holds a BS in Petroleum Engineering from The University of Texas at Austin and is a registered professional engineer with more than 29 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management. Lonquist and its employees have no interest in Houston American Energy Corp, and were objective in determining the results of Houston American Energy's reserves. Lonquist used a combination of production performance, offset analogies, seismic data and their interpretation, subsurface geologic data and core data, along with estimated future operating and development costs as provided by the Company and based upon historical costs adjusted for known future changes in operations or development plans, to estimate our reserves. The Company does not operate any of its oil and gas properties.

Total estimated proved developed and undeveloped reserves by product type and the changes therein are set forth below for the years indicated.

	United States		South America		Total	
	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)
Total proved reserves						
Balance December 31, 2007	135,649	4,012	—	1,281,227	135,649	1,285,239
Extensions and discoveries	—	—	—	211,310	—	211,310
Revisions of prior estimates	(92,127)	(560)	—	(401,350)	(92,127)	(401,910)
Sales of minerals in place	—	—	—	(757,605)	—	(757,605)
Production	(24,748)	(1,511)	—	(122,107)	(24,748)	(123,618)
Balance December 31, 2008	18,774	1,941	—	211,475	18,774	213,416
Extensions and discoveries	15,703	44	—	1,104,041	15,703	1,104,085
Purchase of minerals in place	42,685	1,394	—	—	42,685	1,394
Revisions of prior estimates	8,792	1,100	—	16,493	8,792	17,593
Production	(15,761)	(1,581)	—	(129,782)	(15,761)	(131,363)
Balance December 31, 2009	70,193	2,898	—	1,202,227	70,193	1,205,125
Proved developed reserves						
at December 31, 2008	18,774	1,941	—	141,246	18,774	143,187
at December 31, 2009	70,193	2,898	—	307,993	70,193	310,891
Proved undeveloped reserves						
at December 31, 2008	—	—	—	70,229	—	70,229
at December 31, 2009	—	—	—	894,234	—	894,234

During 2009 and 2008, the Company recorded extensions and discoveries resulting principally from its ongoing drilling operations in Colombia. As of December 31, 2009, our proved undeveloped ("PUD") reserves totaled 894.2 mbls of oil and 0.0 mcf of natural gas, for a total of 894.2 mboe. Positive revisions of 894.2 mboe in PUD reserves were due to the on-going drilling program and subsequent changes in subsurface mapping. None of the PUD reserves as of December 31, 2008 were converted to proved developed producing reserves in 2009. All PUD locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2014. None of our PUD locations have been booked for longer than five years.

The Company experienced downward revisions in estimated proved natural gas and oil reserves in 2008. The revisions to natural gas reserves during 2008 were primarily attributable to a downward revision in volumes of natural gas reserves based on updated well performance from the Company's North American properties. The revisions to oil reserves during 2008 were primarily attributable to downward revisions in the volumes of oil reserves based on updated well performance from the Company's South American properties.

Sales of reserves in place during 2008 represent the June 2008 transaction whereby the Company, through Hupecol Caracara LLC as owner/operator under the Caracara Association Contract, sold all of its interest in the Caracara Association Contract in Colombia.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is computed using average first-day-of the-month prices for oil and gas during the 12 month period for 2009, and using year-end prices for 2008, (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated related future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated), and assuming continuation of existing economic conditions. Future income tax expenses give effect to permanent differences and tax credits but do not reflect the impact of continuing operations including property acquisitions and exploration. The estimated future cash flows are then discounted using a rate of ten percent a year to reflect the estimated timing of the future cash flows.

Standard measure of discounted future net cash flows at December 31, 2009

	United States	South America	Total
Future net cash flow	$ 455,522	$ 66,715,086	$ 67,170,608
Future production cost	(87,192)	(36,712,770)	(36,799,962)
Future development cost		(11,571,920)	(11,571,920)
Future income tax	—	(1,560,871)	(1,560,871)
10% annual discount for timing of cash flow	(44,363)	(2,370,012)	(2,414,375)
Standard measure of discounted future net cash flow relating to proved oil and gas reserves	$ 323,967	$ 14,499,513	$ 14,823,480
Changes in standardized measure:			
Change due to current year operations			
Sales, net of production costs	(91,205)	(3,278,775)	(3,369,980)
Change due to revisions in standardized variables:			
Income taxes	—	(1,312,411)	(1,312,411)
Accretion of discount	10,361	351,301	361,662
Net change in sales and transfer price, net of production costs	(21,603)	3,899,640	3,878,036
Previously estimated development costs incurred during the period	335,070	4,259,860	4,594,930
Changes in estimated future developments costs	(335,070)	(3,526,367)	(3,861,437)
Revision and others	70,166	289,606	359,773
Discoveries	51,631	13,602,240	13,653,871
Purchase of reserves in place	189,626	—	189,626
Changes in production rates and other	35,510	(2,857,593)	(2,822,083)
Net			11,671,988
Beginning of year			3,151,493
End of year			$ 14,823,480

Standard measure of discounted future net cash flows at December 31, 2008

	United States	South America	Total
Future net cash flow	$ 176,794	$ 8,989,877	$ 9,166,671
Future production cost	(73,188)	(4,743,369)	(4,816,557)
Future development cost	—	(733,493)	(733,493)
Future income tax	—	—	—
10% annual discount for timing of cash flow	(24,125)	(441,003)	(465,128)
Standard measure of discounted future net cash flow relating to proved oil and gas reserves	$ 79,481	$ 3,072,012	$ 3,151,493
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(275,944)	(6,979,366)	(7,255,310)
Change due to revisions in standardized variables:			
Income taxes	—	13,727,868	13,727,868
Accretion of discount	61,004	6,949,779	7,010,783
Net change in sales and transfer price, net of production costs	(93,355)	(11,454,408)	(11,547,736)
Previously estimated development costs incurred during the period	—	1,830,066	1,830,066
Changes in estimated future developments costs	—	(641,440)	(641,440)
Revision and others	(614,417)	(4,423,721)	(5,038,138)
Discoveries	—	733,190	733,190
Sales of reserves in place		(41,074,257)	(41,074,257)
Changes in production rates and other	392,157	(10,937,166)	(10,545,009)
Net			(52,800,010)
Beginning of year			55,951,503
End of year			$ 3,151,493