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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): December 7, 2010

GULFPORT ENERGY CORPORATION

(Exact Name of Registrant as Specified in Charter)

Delaware	000-19514	73-1521290
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification Number)

14313 North May Avenue Suite 100 Oklahoma City, OK	73134
(Address of principal executive offices)	(Zip code)

(405) 848-8807
(Registrant's telephone number, including area code)

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K is intended to simultaneously satisfy the filing obligation of the Registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act

Item 8.01. Other Information.

In response to a comment letter received by Gulfport Energy Corporation (the "Company") from the Securities and Exchange Commission (the "SEC") regarding certain of its filings under the Securities Exchange Act of 1934, as amended (the "Comment Letter"), the Company is filing herewith the following table providing a summary of the Company's production, average sales prices and average production costs for oil and gas fields containing 15% or more of the Company's total proved reserves as of December 31, 2009:

	Year Ended December 31,		
	2009	2008	2007
WCBB			
Net Production			
Oil (MBbls)	1,209	1,220	1,330
Natural gas (MMcf)	192	356	479
NGL (Mgal)	—	—	—
Total (Mboe)	1,241	1,280	1,410
Average Sales Price:			
Oil (per Bbl)	$52.39	$80.20	$65.19
Natural gas (per Mcf)	$ 4.44	$10.48	$ 7.82
NGL (per Gal)	$ —	$ —	$ —
Average Production Cost (per BOE)	$ 8.54	$10.86	$ 8.98
Permian Basin			
Net Production			
Oil (MBbls)	118	134	3
Natural gas (MMcf)	236	234	14
NGL (Mgal)	2,694	2,579	—
Total (Mboe)	221	234	6
Average Sales Price:			
Oil (per Bbl)	$55.19	$94.42	$91.67
Natural gas (per Mcf)	$ 3.72	$ 7.57	$ 6.80
NGL (per Gal)	$ 0.73	$ 1.26	$ —
Average Production Cost (per BOE)	$10.71	$11.59	$ —

In response to the Comment Letter, the Company is also filing herewith as Exhibits 99.1 and 99.2, respectively, the revised reports from Netherland, Sewell & Associates, Inc. and Pinnacle Energy Services, LLC, together with their respective consents filed as Exhibits 23.1 and 23.2. To address certain of the SEC comments, each revised report discloses the relevant average prices weighted by production over the remaining lives of the properties covered by such reserve report. The revised reports also contain certain other changes or additions to the text of the reports previously filed. The revised reports, however, do not change any of the reserve information previously disclosed by the Company.

In addition, in response to the Comment Letter, the Company is filing herewith as Exhibit 10.1 a summary of the oral employment agreement with its Chief Executive Officer, which agreement was previously disclosed in the Company's filings with the SEC.

Item 9.01. Financial Statements and Exhibits

(d) *Exhibits*

Number	Exhibit
10.1	Summary of Oral Employment Agreement with James D. Palm.
23.1	Consent of Netherland, Sewell & Associates, Inc.
23.2	Consent of Pinnacle Energy Services, LLC.
99.1	Report of Netherland, Sewell & Associates, Inc.
99.2	Report of Pinnacle Energy Services, LLC.

SIGNATURE

Pursuant to the requirements 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.

GULFPORT ENERGY CORPORATION

Date: December 7, 2010

By: /s/ MICHAEL G. MOORE
Michael G. Moore
Chief Financial Officer

Exhibit Index

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99.2	Report of Pinnacle Energy Services, LLC.

Exhibit 10.1

Summary of Oral Employment Agreement

Gulfport Energy Corporation (the "***Company***") has entered into an oral agreement with James D. Palm, the Company's Chief Executive Officer, with respect to his compensation and benefits, pursuant to which Mr. Palm is entitled to an annual salary of $200,000 and, at the discretion of the Company's board of directors (the "***Board of Directors***"), an annual cash incentive bonus. The compensation committee of the Board of Directors (the "***Compensation Committee***") may make upward adjustments to Mr. Palm's salary. For 2009, Mr. Palm's annual salary was $225,000. To date, the Compensation Committee has made no adjustments to Mr. Palm's annual salary for 2010. Mr. Palm is also eligible to participate in all insurance, retirement and benefits plans available to the Company's other employees.

Exhibit 23.1

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

We hereby consent to the inclusion in the Form 8-K of Gulfport Energy Corporation ("Form 8-K"), of our report dated December 1, 2010, on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2009, to all references to our firm in the Form 8-K and to the incorporation by reference of said report in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Forms S-3 (File No. 333-168180, effective July 28, 2010; File No. 333-146988, effective November 13, 2007; File No. 333-143659, effective July 18, 2007; and File No. 333-139480, effective January 23, 2007).

NETHERLAND, SEWELL &
ASSOCIATES, INC.

By: /s/ J. Carter Henson, Jr.
J. Carter Henson, Jr., P.E.
Senior Vice President

Houston, Texas
December 3, 2010

Exhibit 23.2

CONSENT OF PINNACLE ENERGY SERVICES, LLC

We have issued our report letter dated December 3, 2010 for 2009, on estimates of proved reserves and future net cash flows of certain oil and natural gas properties located in the Permian Basin of West Texas acquired by Gulfport Energy Corporation ("Gulfport") on December 20, 2007 from ExL Petroleum, LP and certain other sellers. As independent oil and gas consultants, we hereby consent to the inclusion of the information contained in our report letter in this Current Report on Form 8-K of Gulfport (this "Current Report") and to all references to our firm in this Current Report. We hereby also consent to the incorporation by reference of such information in the Registration Statements of Gulfport on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Forms S-3 (File No. 333-168180, effective July 28, 2010; File No. 333-146988, effective November 13, 2007; File No. 333-143659, effective July 18, 2007; and File No. 333-139480, effective January 23, 2007).

PINNACLE ENERGY SERVICES, LLC

/s/ John Paul Dick

Name: John Paul Dick

Title: Manager, Registered Petroleum Engineer

December 3, 2010

Oklahoma City, Oklahoma

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

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JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

December 1, 2010

Mr. Mike Moore
Gulfport Energy Corporation
14313 North May Avenue, Suite 100
Oklahoma City, Oklahoma 73134

Dear Mr. Moore:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2009, to the Gulfport Energy Corporation (Gulfport) interest in certain oil and gas properties located in West Cote Blanche Bay Field, St. Mary Parish, Louisiana. It is our understanding that the proved reserves estimated in this report constitute approximately 27.5 percent of all proved reserves owned by Gulfport. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of overhead expenses and future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. The estimates in this report are the same as those presented in our report dated February 9, 2010. However, portions of this letter have been revised based on comments received by Gulfport from the SEC. This report has been prepared for Gulfport’s use in filing with the SEC.

We estimate the net reserves and future net revenue to the Gulfport interest in these properties, as of December 31, 2009, to be:

	Net Reserves		Future Net Revenue ($)	
Category	**Oil (Barrels)**	**Gas (MCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	967,646	540,464	27,469,900	27,025,900
Proved Developed Non-Producing	2,283,124	606,665	39,466,400	30,299,700
Proved Undeveloped	1,776,882	426,165	62,443,800	49,206,300
Total Proved	5,027,652	1,573,294	129,380,100	106,531,900

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

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

Future gross revenue to the Gulfport interest is prior to deducting state production taxes. Future net revenue is after deductions for these taxes, future capital costs, operating expenses, and abandonment costs but before consideration of federal income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

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netherlandsewell.com

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Our estimates of future revenue do not include any salvage value for the lease and well equipment but do include Gulfport's estimates of the costs to abandon the wells and production facilities.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2009. For oil volumes, the average Shell Trading (US) Company West Texas/New Mexico Intermediate posted price of $57.90 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $3.866 per MMBTU is adjusted for energy content, transportation fees, and a regional price differential. As requested, an economic projection is included in the proved developed producing category to account for the incremental income received from certain oil price hedge contracts currently in place. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $57.37 per barrel of oil and $3.808 per MCF of gas.

Lease and well operating costs used in this report are based on operating expense records of Gulfport, the operator of the properties. As requested, lease and well operating costs are limited to direct lease- and field-level costs. Headquarters general and administrative overhead expenses of Gulfport are not included. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

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

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. Estimates of reserves may increase or decrease as a result of future operations, market conditions, or changes in regulations.

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

The titles to the properties have not been examined by Netherland, Sewell & Associates, Inc. (NSAI), nor has the actual degree or type of interest owned been independently confirmed. The data used in our estimates were obtained from Gulfport, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in our office. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

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

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Vice President

Date Signed: December 1, 2010

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: December 1, 2010

DFN:KEA

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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

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

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

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

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

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

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

Supplemental definitions from the 2007 Petroleum Resources Management System:

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

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

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

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

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

(iv) Provide improved recovery systems.

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

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

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

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

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

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

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

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

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

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

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

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

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

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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

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

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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

(20) *Production costs.*

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

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

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

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

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

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

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

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

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

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

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

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

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

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

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

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

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

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

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

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

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

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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

Exhibit 99.2

PINNACLE
Energy Services, L.L.C.

December 3, 2010

Gulfport Energy Corporation
14313 N. May Ave., Ste. 100
Oklahoma City, OK 73134

Attn: Mr. Steve Baldwin

Re: Reserves & Economic Evaluation
SEC Year End 2009
Permian Properties

EXECUTIVE SUMMARY

Pursuant to your request, an engineering and economic evaluation was prepared for projected oil and gas reserves associated with interests owned by Gulfport Energy Corporation ("Gulfport") in certain oil and gas properties located in the Permian Basin, in West Texas, that are operated by Windsor Energy Group, LLC ("Windsor"). The properties include sixty-four (64) Proved Producing (PDP) wells, sixteen (16) Proved Behind-Pipe (PDBP) wells, two (2) Proved Non-Producing (PDNP) wells and one hundred ninety-one (191) Proved Undeveloped (PUD) locations. Remaining reserves and future and present worth values for these properties were calculated as of January 1, 2010. It is our understanding that the proved reserves estimated in this report constitute approximately 58% of all proved reserves owned by Gulfport as of December 31, 2009.

The total gross and net reserves and future cumulative cashflows, both undiscounted and discounted (at 10%) prior to considering the effects of Federal Income Taxes for all properties, are summarized in TABLE 1 below. Economics were prepared using the yearend 2009 SEC price forecast.

TABLE 1
Reserves and Economic Summary

Reserve Category	# Wells	Rem Net Oil MBbls	Rem Net Gas MMcf	Rem Net NGL MGal	Net Capital M$	Net Cashflow M$	Net Disc PV @ 10%, M$
PDP	64	817	1,556	14,818	0	37,577	21,939
PDBP	16	221	358	3,585	1,200	12,428	6,322
PDNP	2	60	95	994	633	2,636	1,395
PUD	191	6,173	8,885	85,299	120,808	197,324	61,776
Total Proved	**273**	**7,271**	**10,894**	**104,696**	**122,640**	**249,965**	**91,432**

The reserve classifications meet the criteria for Proved reserves under the SEC guidelines as of January 1, 2010. All working and net revenue interests were provided by Gulfport. Historical production and geological data was provided by Windsor and was supplemented by data gathered from public sources. All of the information provided to us or gathered by us was assumed to be accurate and correct and was not independently verified.

Results of the evaluations showing forecasts of production, reserves, revenues, and income for each well are presented in a yearly format, and are attached and made part of this reports appendices. The gross production graphs and forecasts (by well/lease) and a one-line economic summary (by well/lease) of the results from the evaluation are also included in the appendices.

ECONOMIC EVALUATION

FUTURE INCOME

Future net revenue in this report includes deductions for state production taxes. Future net income is after deducting production taxes, future capital investments, and lease operating expenses, but before consideration of any state and/or federal income taxes. No provisions for salvage value or abandonment costs, which are generally assumed to offset each other, were been included in this evaluation. Future net income has not been adjusted for any outstanding loans that may exist or cash on hand or undistributed income. The future net income has been discounted at various annual rates, including the standard ten percent (10%), to determine its "present worth." The present worth is shown to indicate the effect of time on the value of money.

PRODUCT PRICING

The reserves and economic evaluation was performed based on the yearend 2009 benchmark SEC prices of $61.18 per bbl oil and $3.87 per mmbtu gas, which were calculated as the twelve (12) month unweighted arithmetic average of the NYMEX Prices posted on the first day of each calendar month during 2009 per SEC guidelines. The prices received by Gulfport during the calendar year were analyzed and compared to the average 2009 SEC prices and a weighted by production average price and differential for oil and gas prices were determined. These differentials reflect adjustments necessary for BTU content, field losses and usage, and gathering and processing costs. For oil, a downward adjustment of $2.34/bbl was calculated and for natural gas, a downward adjustment of 6.01% was determined. Thus, the average prices weighted by production over the remaining lives of the properties are $58.84 per barrel of oil and $3.63 per Mcf of gas. The weighted by production average price for natural gas liquids (ngl), which are produced from processing the wet natural gas production stream, was calculated to be $0.70 per gal (29.40 $/BBl), which is 48.05% of the SEC average oil price of $61.18 per bbl .

The plant statements for each lease were provided by Windsor and analyzed to determine the natural gas liquids (NGL) Yield and the percent loss of wellhead gas, or Shrink factor. These parameters were entered into the economic model to forecast the NGL production.

EXPENSES

Individual well operating expenses for the previous twelve months were taken from actual lease operating statements provided by Windsor. These expenses were analyzed and adjusted to calculate the average re-occurring monthly expense for each well less water disposal costs. Water production for each well was forecasted and expensed at $1.25 per barrel for all areas. A new salt water disposal well in the Bloxom area will be online in March 2010 and the salt water disposal costs were reduced in the economic analysis to $0.25/bbl.

FUTURE WELL INVESTMENTS

Future well drilling and completion costs were provided by Windsor and estimated to be $1.265 MM per well based on historical data and current AFE's provided. Recompletion costs were assumed to be $100,000 per well. Capital timing for the first three (3) years was provided by Windsor. Pinnacle cannot be responsible for capital costs that exceed or are less than these estimates.

RESERVE DETERMINATION

RESERVE DISCUSSION

Remaining recoverable reserves are those quantities of petroleum that are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty depending primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty is conveyed by classifying reserves as Proved (highly certain) or Non-Proved (less certain). Detailed reserve definitions are provided in attachments to this report.

The estimated reserves and revenues shown in this report were determined by SEC standards for Proved Developed Producing (PDP) reserve category. Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs with defined limits and under current economic conditions, operating methods, and government regulations.

Proved Developed Producing (PDP) is assigned to wells with sufficient production history to allow material balance and decline curve analysis to be the primary methods of estimation. PDP reserves are the most reliable reserves, generally with a high degree of confidence (>90%) that actually recovered quantities will equal or exceed published reserve estimates. Proved Developed Non-Producing (PNP) reserves include zones that have been penetrated by drilling but have not produced sufficient quantities to allow material balance or decline curve analysis with a high degree of confidence. This category includes Proved Developed Behind-Pipe (PNPBP) zones and tested wells awaiting production equipment (PNP).

Proved Undeveloped (PUD) reserves are those quantities of petroleum that are estimated to be recovered from undrilled acreage (locations) in a continuous portion of the Proved Developed reservoir as defined by offsetting PDP wells and geological interpretations. The Proven Undeveloped and Non-Producing wells were forecasted based on geological data presented, volumetric calculations, and analog comparisons to existing completions. Non-Proven (Probable) Undeveloped locations have been evaluated to be likely productive but do not meet SEC criteria to be classified as Proved at this time.

GENERAL

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserves were estimated using industry accepted engineering practices that we considered to be appropriate and necessary under the circumstances and were primarily based on historical rate decline analysis determined from existing producers in an analogous field. When possible and practical, pressure tests, material balance techniques and analogies were integrated into the reserve estimates. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future.

The revenue from these reserves and the actual costs to produce may be more or less than the estimated amounts and may consequently cause an increase or decrease in future reserve estimates. In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting, rather than engineering interpretation, may be controlling. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Accordingly, note that as in all aspects of oil and gas evaluation the accuracy of any reserve estimate is solely a function of engineering interpretation and judgment and should be accepted with the understanding that future production or unanticipated events subsequent to this report could justify revision of these reserve estimates – either increases or decreases.

Pinnacle Energy Services, L.L.C. is an established petroleum engineering consulting firm. We hereby confirm that neither this firm, it's affiliates, nor any of its employees, members, officers, or directors has, or is committed to acquire any interest, directly or indirectly, in the properties covered by this report, in any partnership, any general partner of the partnerships, nor is this firm or any employee, member or officer, or director thereof otherwise affiliated with any partnership or any such general partner. This report was completely, independently prepared by Pinnacle Energy Services L.L.C. and our engagement and payment for services in connection with this report is independent of the outcome and not on a contingent basis.

The titles to the properties have not been examined nor has the actual degree or type of interest owned been independently confirmed. Pinnacle Energy Services personnel have not conducted any field production test or field inspection of the properties as this is not usually considered necessary for the purpose of this report. Additionally, an "audit" of the information obtained from public sources or provided by the operator and/or owner of these properties has not been conducted to confirm its accuracy. Pinnacle Energy Services, L.L.C. can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Pinnacle Energy Services, LLC

John Paul (J.P.) Dick, P.E.
Petroleum Engineer

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