TORRENT ENERGY CORP
Form 10-K
July 15, 2008

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

FORM 10-K

(Mark One)

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

For the fiscal year ended March 31, 2008

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

For the transition period from [ ] to [ ]

Commission file number 000 19949

Torrent Energy Corporation
(Exact name of registrant as specified in its charter)

Colorado	84-1153522
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

11918 SE Division, Suite 197 Portland, Oregon	97266
(Address of principal executive offices)	(Zip Code)

Issuer’s telephone number: 503.224.0072

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

Title of each class	Name of each exchange on which registered
Nil	Nil

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

Shares of Common Stock, $0.001 par value
(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 [X]

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

Indicate by check mark whether the issuer (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 [X]   No [   ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained in this form, 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 definitions of “large accelerated filer”, 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 [X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b 2 of the Exchange Act) Yes [ ] No [X]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was sold, or the average bid and asked prices of such common equity, as of a specified date within 60 days. (See definition of affiliate in Rule 12b 2 of the Exchange Act.)

41,012,047 shares of common stock at $0.04 per share = $1,640,482

(1) Closing price on July 11, 2008.

State the number of shares outstanding of each of the issuer’s classes of equity stock, as of the latest practicable date.

41,732,547 shares of common stock issued and outstanding as of July 11, 2008

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III (Items 10, 11, 12,13 and 14) of this Form 10-K is incorporated by reference from our definitive proxy statement to be filed pursuant to Regulation 14A with the Commission not later than 120 days after the end of the fiscal year covered by the Form 10-K.

ITEM 1. BUSINESS

Torrent Energy Corporation is an exploration stage energy company committed to the pursuit of unconventional natural gas niche opportunities located primarily in North America. As used in this annual report, the terms “our Company”, “we”, “us” and “our” mean Torrent Energy Corporation, and our wholly owned subsidiaries, Methane Energy Corp. and Cascadia Energy Corp., unless otherwise indicated. A brief history of our Company is provided in the section entitled “Corporate History” below.

This annual report contains forward-looking statements as that term is defined in the Private Securities Litigation Reform Act of 1995. These statements relate to future events or our future financial performance. In some cases, you can identify forward-looking statements by terminology such as “may”, “should”, “expects”, “plans”, “anticipates”, “believes ” “estimates”, “predicts”, “potential” or “continue” or the negative of these terms or other comparable terminology. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including the risks in the section entitled “Risk Factors”, that may cause our Company or our industry’s actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by these forward-looking statements.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements. Except as required by applicable law, including the securities laws of the United States, we do not intend to update any of the forward-looking statements to conform these statements to actual results.

Our audited consolidated financial statements are stated in United States dollars and are prepared in accordance with United States Generally Accepted Accounting Principles. All references to “CDN$” refer to Canadian dollars.

Proceedings Under Chapter 11 of the Bankruptcy Code

The following discussion provides general background information regarding our bankruptcy cases, and is not intended to be an exhaustive description. Access to documents filed with the U.S. Bankruptcy Court and other general information about the U.S. bankruptcy cases is available at www.orb.uscourts.gov. The content of the foregoing website is not a part of this report.

On June 2, 2008, the Company commenced Chapter 11 proceedings (Case No. 08-32638) by filing a voluntary petition for reorganization under the Bankruptcy Code with the United States Bankruptcy Court for the District of Oregon (the “Bankruptcy Court”). Each of the Company’s subsidiaries, Methane Energy Corp. and Cascadia Energy Corp. (which we refer to collectively with the Company as the "Debtors"), also commenced a case under Chapter 11 of the Bankruptcy Code on the same day (together with the Company’s filing, the “Chapter 11 Cases”). The Debtors continue to operate their businesses and manage their properties as debtors-in-possession pursuant to Sections 1107(a) and 1108 of the Bankruptcy Code.

In connection with the Chapter 11 Cases, on June 6, 2008, we entered into a senior secured super-priority debtor in possession credit and guaranty agreement (the “DIP Credit Agreement”) among the Company and its subsidiaries, as Guarantors, and YA Global Investments, L.P., as lender (" YA Global "). The DIP Credit Agreement was approved on an interim basis by the Bankruptcy Court the same day. The Bankruptcy Court entered an order approving the DIP Credit Agreement on July 11, 2008.

The DIP Credit Agreement provides for a $4.5 million term loan under which YA Global may advance funds to us (the "Loan "). The proceeds of the Loan are expected to be used for working capital purposes, including payment of professional services fees, wages, salaries, and other operating expenses, payment of the promissory note issued by the Company to YA Global on May 15, 2008, in the amount of $207,854 plus accrued interest, payment of certain subsidiary debt, and other purposes, as approved by YA Global. Advances under the DIP Credit Agreement bear interest at the lower of twelve percent (12%) per annum or the highest rate of interest permissible under law. The Loan will mature on the earliest of (a) the date which is the one year anniversary of the DIP Credit Agreement, (b) the date of termination of the Loan in connection with YA Global's rights upon an Event of Default (as defined in the DIP Credit Agreement), (c) the close of business on the first business day after the entry of the final order by the Bankruptcy Court, if the Company has not paid YA Global the fees required under the DIP Credit Agreement, (d) the date a plan of reorganization confirmed in the Chapter 11 Cases becomes effective that does not provide for the payment in full of all amounts owed to YA Global under the DIP Credit Agreement, (e) the date of the closing of a sale of all or substantially all of our assets pursuant to Section 363 of the Bankruptcy Code, and (f) the effective date of a plan of reorganization or arrangement in the Chapter 11 Cases.

If the Loan is repaid prior to the one year anniversary of the date of the DIP Credit Agreement, we will be required to pay to YA Global a prepayment fee in an amount equal to one percent (1%) of such prepayment. Upon the occurrence of an Event of Default, all amounts owing under the DIP Credit Agreement will bear interest at the rate of the lower of seventeen percent (17%) or the maximum rate permitted by law per annum, and YA Global may declare all outstanding obligations immediately due and payable. YA Global has a right of first refusal to provide exit financing to the Company. As of July 11, 2008, we have borrowed $591,026 under the DIP Credit Agreement.

On June 16, 2008, we filed with the Bankruptcy Court our Joint Plan of Reorganization for Reorganizing the Debtors (the “Plan”) and a Disclosure Statement Regarding Joint Plan of Reorganization for Reorganizing the Debtors. In addition to the DIP Credit Agreement, the Plan also includes a rights offering, under which current shareholders of the Company will have the opportunity to purchase additional new equity of the Company (the "Rights Offering"), subject to Bankruptcy Court approval and other conditions.

The administrative and reorganization expenses resulting from the Chapter 11 process will unfavorably affect our results of operations. Future results of operations may also be adversely affected by other factors related to the Chapter 11 process. See Item 1A – Description of Business – Risk Factors of this annual report for a discussion of risks and uncertainties relating to the Chapter 11 process.

Corporate History

We were formed by the merger of Scarab Systems, Inc., a Nevada corporation, with iRV, Inc., a Colorado corporation, on July 17, 2002. We were initially involved in the business of providing services to the e commerce industry. However, we ceased all activities in the e-commerce industry by the end of the fiscal year ended March 31, 2003. Scarab Systems, Inc. was a privately owned corporation incorporated on October 8, 2001. Subsequent to completion of the reorganization, Scarab Systems, Inc. transferred all its assets and liabilities to iRV, Inc. The directors and executive officers of iRV, Inc. were subsequently reconstituted. iRV, Inc. changed its name to Scarab Systems, Inc. on March 24, 2003.

We were given two options in fiscal year 2002 to acquire all the issued and outstanding shares of 485017 B.C. Ltd., a British Columbia company doing business as MarketEdge Direct. These options were given to us as security against a subscription receivable of $337,500 for 675,000 shares of our common stock from the shareholders of MarketEdge Direct. MarketEdge Direct was in the business of providing a wide range of marketing products and services. Effective August 7, 2002, we exercised both of the options and acquired all the issued and outstanding shares of MarketEdge Direct. Due to disappointing financial results of MarketEdge Direct, on March 28, 2003, we entered into an agreement with the former shareholders of MarketEdge Direct to sell MarketEdge Direct back to them. As a result, all the issued and outstanding shares of MarketEdge Direct that we acquired were sold back to the former MarketEdge Direct shareholders for the return to treasury of 540,000 shares of our common stock.

On March 28, 2003, we acquired all the issued and outstanding shares of Catalyst Technologies, Inc., a British Columbia corporation. Catalyst was a Vancouver-based, web design and Internet application developer. Catalyst specialized in the development of web-sites and Internet software design, primarily for the health and nutraceutical industry. The acquisition of Catalyst was treated as a non-material business combination in fiscal year 2003, and we discontinued Catalyst’s operations during the fiscal year ended March 31, 2004 due to a lack of working capital and disappointing financial results.

On April 30, 2004, we incorporated an Oregon subsidiary company named Methane Energy Corp. in anticipation of acquiring oil and gas properties in the State of Oregon. On May 11, 2004, Methane Energy Corp. entered into a lease purchase and sale agreement with GeoTrends-Hampton International, LLC to purchase GeoTrends-Hampton International’s undivided working interest in certain oil and gas leases for the Coos Bay Basin prospect located onshore in the Coos Bay Basin of Oregon.

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To acquire this oil and gas leases, we paid a total of $300,000 in cash, issued 1,800,000 restricted shares of our common stock in three performance-based tranches, and granted a 4% overriding royalty interest upon production from lands and leases in the Coos Bay project area. The lease purchase and sale agreement closed on June 22, 2004. Upon closing, we paid $100,000 in cash and issued 600,000 shares of our common stock. We subsequently paid the remaining $200,000 cash consideration and have issued an additional 1,200,000 shares of our common stock to satisfy the remaining components of the purchase obligation.

Pursuant to the lease purchase and sale agreement with GeoTrends-Hampton International, LLC, we acquired leases of certain properties in the Coos Bay area of Oregon that are believed to be prospective for oil and gas exploration. Additional leases were subsequently acquired from the State of Oregon and from private property owners. We have amassed approximately 118,000 acres under lease with annual lease rental payments totaling approximately $93,000. We continue to seek additional lease properties in the Coos Bay area.

As a result of the change in our business focus, we received shareholder approval on July 13, 2004 to change our name from Scarab System, Inc. to Torrent Energy Corporation.

On June 29, 2005, we incorporated a Washington subsidiary company named Cascadia Energy Corp. in anticipation of acquiring oil and gas properties in the State of Washington. Cascadia Energy Corp. executed a lease option agreement dated August 9, 2005 with Weyerhaeuser Company to lease 100,000 acres that it could select from an overall 365,000 acre block in the Chehalis Basin located in Lewis, Cowlitz and Skamania Counties of Washington. We have commenced an exploratory work program on certain acreage, searching for possible hydrocarbon deposits. Cascadia Energy Corp. was also granted a two year first right of refusal on the balance of the Weyerhaeuser acreage. Initial cash consideration for this option was $100,000 and we paid $60,000 and our joint venture partner, St. Helens Energy, LLC paid $40,000. On or before the end of the initial first year, Cascadia Energy Corp. was to elect either to undertake a work commitment of $285,715 pertaining to the full 100,000 acres (proportionately reduced if Cascadia Energy Corp. elects to evaluate less than the entire acreage) or pay Weyerhaeuser $285,715 in lieu of the work commitment or such lesser amount if less than the full 100,000 acres is chosen to be evaluated, but in no event less than 50,000 acres. On July 25, 2007 Weyerhaeuser agreed to extend the option for an additional 120 days and waive the $285,715 work commitment for a payment of $100,000 of which we paid $60,000 and St. Helen's Energy LLC paid $40,000. We did not fulfill our commitment within that time frame and the option is now terminated.

Cascadia Energy Corp. has maintained the joint venture agreement dated August 12, 2005 with St. Helens Energy, LLC, a 100 percent owned subsidiary of Comet Ridge Limited, an Australian coal seam gas explorer listed on the Australian Stock Exchange, and headquartered in Perth, Western Australia. Under this agreement, St. Helens Energy, LLC holds a 40 percent interest in the Company's Washington exploration project. Cascadia Energy Corp. serves as operator of the joint venture and St. Helens Energy, LLC actively assists in evaluating the area and developing exploratory leads and prospects.

The joint venture provides for Cascadia Energy Corp. and St. Helens Energy, LLC, to share the costs of exploring, developing and operating any economic natural gas resources discovered in the Chehalis Basin area. Capital and operating costs, as well as any resulting revenues associated with the project area, are to be allocated 60 percent to Cascadia Energy Corp. and 40 percent to St. Helens Energy, LLC. Cascadia Energy Corp. acts as the operator of the venture and submits authorizations for expenditures to its joint venture partner for approval on a periodic basis. At any time, St. Helens Energy, LLC may decline to participate; i.e. non-consent, in which case Cascadia Energy Corp. will absorb 100 percent of the cost of a specific authorization for expenditure and receive 100 percent of any net revenues derived from the specific expenditure. Alternatively, Cascadia Energy Corp. might also choose not to undertake the expenditure absent joint venture partner participation. St Helen's Energy, LLC has subsequently sold a portion of their working interest percentage to Citrus Energy Corporation.

On April 10, 2008, Cascadia granted a one -year option to Citrus Energy Corporation and Oklaco Holding, LLP, (the "Citrus Group") which gives the Citrus Group the right to drill two potential wells on Cascadia's Chehalis leases and earn a working interest in potential production from certain acreage currently held by Cascadia. In the event the Citrus Group elects to drill these potential wells, then Cascadia would receive a cash equalization payment of $80,000 per well and would retain a royalty interest on any future production from the acreage earned by the Citrus Group.

Cascadia Energy Corp continues to hold lease agreements with Weyerhaeuser totaling 36,991 acres, two that required payment of upfront lease bonuses of $428,610 and one which requires annual lease payments of $1,275. Certain of these agreements include a provision requiring Cascadia Energy Corp. to commence a well within the first two years of the lease, or the lease will terminate and we would be required to make a payment of $75,000 to Weyerhaeuser in May of 2009.

On May 9, 2006, Cascadia Energy Corp., entered into an option to acquire oil & gas leases located in the Chehalis Basis from Pope Resources LP. This option provides Cascadia Energy Corp. with the right to earn oil and gas leases covering 15,280 acres of mineral rights interests held by Pope Resources LP. for a purchase price of $1 per net mineral acre or $15,280. The initial term of this option was for a period of 18 months ending on November 9, 2007. If Cascadia Energy Corp. expended $200,000 on operations and activities during the initial term, and on September 12, 2007 Pope Resources signed a letter agreement extending the option until November 9, 2008.

As of July 11, 2008, the total acreage under lease from the State of Washington was 23,735 acres with lease terms of four years. This acreage was acquired in lease auctions for aggregate consideration of $37,719.

Other than as set out herein, we have not been involved in any bankruptcy, receivership or similar proceedings, nor have we been a party to any material reclassification, merger, consolidation or purchase or sale of a significant amount of assets not in the ordinary course of our business.

Current Business

We are an exploration stage company engaged in the exploration for coalbed methane in the Coos Bay region of Oregon and in the Chehalis Basin region of Washington State. Through one of our wholly owned subsidiaries, Methane Energy Corp., we now hold leases to approximately 107,000 acres of prospective coalbed methane lands in the Coos Bay Basin. Methane Energy Corp. operates the exploration project in the Coos Bay Basin. Through our other wholly-owned subsidiary, Cascadia Energy Corp., we are evaluating approximately 91,200 acres under private and state leases located in the Chehalis Basis.

Coos Bay Basin Exploration Prospect

The Coos Bay Basin is located along the Pacific coast in southwest Oregon, approximately 200 miles south of the Columbia River and 80 miles north of the Oregon / California border. The onshore portion of the Coos Bay Basin is elliptical in outline, elongated in a north-south direction and covers over 250 square miles. More than 150,000 acres in the Coos Bay Basin are underlain by the Coos Bay coal field and appears prospective for coalbed methane gas production. The current leasehold position owned by Methane Energy Corp. covers most of the lands believed to be prospective for coalbed methane production in the Coos Bay Basin. Additional leasing, title and curative work continues. Most areas in Coos County are accessible year-round via logging and fire control roads maintained by the county or by timber companies. In addition, numerous timber recovery staging areas are present and in many cases can be modified for drill-site locations.

The Coos Bay Basin is basically a structural basin formed by folding and faulting and contains a thick section of coal-bearing sediments. Coal-bearing rocks contained within the Coos Bay Basin form the Coos Bay Coal field. Coal mining from the Coos Bay field began in 1854 and continued through the mid 1950’s. Much of the coal was shipped to San Francisco. Since mining activity ended several companies such as Sumitomo, Shell and American Coal Company have done exploratory work and feasibility studies on the Coos Bay Coal Field but no mining operations were conducted. In addition, approximately 20 exploratory oil and/or gas wells have been drilled in the Coos Bay basin during the years1914 to 1993. Many of these wells encountered gas shows in the coal seams that were penetrated during drilling.

Coalbeds are contained in both the Lower and Upper Member of the Middle Eocene Coaledo Formation. The coal-bearing sandstones and siltstones of the Middle Eocene Coaledo formation are estimated to form a section up to 6,400 feet thick. Total net coal thickness for the Lower Coaledo Member can range up to 70 feet and over 30 feet for the Upper Coaledo Member. Coos Bay coal rank ranges from sub bituminous to high-volatile bituminous, with a heating value of 8,300 to 14,000 British Thermal Units per pound (“BTU/LB.”), low sulphur content, and a moderate percentage of ash.

On October 6, 2004, a multi-hole coring program was commenced on the Methane Energy Corp. leases. Coring was needed to collect coal samples so that accurate gas content data could be measured. Cores were collected, desorption work was done on the coals and evaluation completed by mid 2005. This data, as well as other geologic information, was provided to Sproule Associates, Inc., an international reservoir engineering firm, for an independent evaluation. To date, natural gas analyses performed on samples from Methane Energy Corp. coal samples and wells indicate that the gas is pipeline quality and that the coals are fully saturated with gas. It is important to note that technically recoverable gas volumes do not necessarily qualify as proved reserves, and we have not recorded any proven reserves at any of our projects at this time.

Drilling and testing programs were then initiated at three pilot sites—Beaver Hill, Radio Hill and Westport. A total of twelve exploratory wells have been drilled. Five exploratory wells were drilled and completed at Beaver Hill; two exploratory wells were drilled at Radio Hill with one completion; and five exploratory wells were drilled at Westport with four of the wells completed. Production and flow testing at the pilot well sites have been completed and development work is planned in the next fiscal year, subject to availability of sufficient working capital.

Natural Gas Market

Until 2005, the Port of Coos Bay was one of the largest population centers on the west coast not served by natural gas. A project to bring natural gas into the region via a 52-mile, 12-inch pipeline was approved, funded by Coos County and the State of Oregon, and completed in late 2004 with gas sales beginning in early 2005. While the line is owned by Coos County, the local gas distribution company, Northwest Natural Gas, operates the line. Northwest Natural Gas serves Coos County and most of western Oregon. The pipeline and its associated distribution system represent the most likely market option for delivery of gas, if produced by Methane Energy Corp. in the future. Estimates of current local Coos County market requirements are less than 1 million cubic feet of gas per day initially, which represents less than 1% of ultimate pipeline capacity. Excess capacity is available for additional gas input.

Coos County is also likely to benefit from new industrial, commercial and residential development as natural gas is now available. Expansion of the market is likely to bring greater demand for and value to natural gas. Because of its west coast location, Coos Bay market prices would be subject to pricing standards of the New York Mercantile Exchange for most of the year. Regional gas pricing hubs are located at Malin and Stanfield, Oregon. The closest pricing point, however, would be the Coos Bay City Gate, where Northwest Natural Gas’s retail rates are set and regulated by Oregon’s Public Utilities Commission. Seasonal or critical gas demand fluctuations could cause prices to exceed or fall below posted prices on a regular basis.

Exploration Objectives

The Coos Bay Basin is the southernmost of a series of sedimentary basins that are present in western Oregon and Washington west of the Cascade Range. The region containing this series of basins is generally referred to as the Puget-Willamette Trough. These basins contain thick sequences of predominantly non-marine, coal-bearing sedimentary rock sequences that are correlative in age, closely related in genesis, and very similar in many other characteristics. Methane Energy Corp. is primarily targeting natural gas from coal seams of the Coaledo Formation in the Coos Bay Basin. Secondary objectives are natural gas, and possibly oil, trapped in conventional sandstone reservoirs.

Indications of the hydrocarbon potential in the Puget-Willamette Trough are shown by natural gas production at the Mist Field in northwest Oregon, the presence of excellent quality sand reservoir development at the Jackson Prairie Gas Storage Field in southwest Washington, and numerous oil and/or gas shows from historic oil and gas exploration drilling activity.

Chehalis Basin Exploration Prospect

The Chehalis Basin is located about midway between Portland and Seattle in southwest Washington State, approximately 90 miles north of the Columbia River. The Chehalis Basin lies between the western foothills of the Cascade Range and the eastern border of the Coast Ranges and is a structurally-formed basin that contains and is flanked by a thick section of coal-bearing sediments. The coals are hosted by Lower-Middle-Upper Eocene continental sedimentary rocks. The coal-bearing Eocene sandstone and siltstone section is estimated to be approximately 6,600 feet thick.

The Chehalis Basin is more or less centered within the sub bituminous and lignite coal fields of southwestern Washington. Sub bituminous and lignite are various types of coal. The Centralia-Chehalis coal district lies to the north and portions of the Morton and Toledo coal fields lie to the east and south, respectively. The Centralia-Chehalis coal district is the largest of the sub bituminous and lignite fields of southwestern Washington. At least 13 separate coal seams have been mined or are being mined from the district. Most coal suitable for mining has a sub bituminous C rank, contains 14% to 35% moisture, 5% to 25% ash, and has a heating value ranging from 8,300 to 9,500 BTU/LB.

TransAlta currently operates a coal-fired power plant and a gas-fired power plant at their Centralia complex. The coal-fired plant produces 1,404 megawatts, enough electricity to supply a city the size of Seattle. In November 2006, the Centralia coal mine adjacent to the power plant closed due to the high cost of operations. Currently, coal to supply the gas-fired power plant is purchased from the states of Wyoming and Montana.

Coals in the Chehalis Basin are relatively thick and continuous. These coals contain a methane gas resource. Limited core and desorption work showed gas content ranging from 6 to 86 standard cubic feet per ton in the coal seams. Two seams, the “ Blue” and the “Brown”, each attain thicknesses of about 40 feet. Total net coal typically approaches 75 feet and in some areas, exceeds 100 feet in thickness. More than 250,000 acres in the Chehalis Basin appears prospective for methane production from the coals. In addition, conventional gas potential is present.

During the 1980’s Kerr-McGee conducted a shallow coal exploration drilling program along the southwest flank of the Chehalis Basin. They encountered a number of gas shows associated with both coals and sandstones. One of the show wells was offset by Duncan Oil in 2001 and it flow tested 714 thousand cubic feet per day from a sand zone.

Our subsidiary, Cascadia Energy Corp., currently controls, through lease options and oil and gas leases, approximately 91,200 acres in the Chehalis Basin. Access to virtually all areas in our Chehalis Basin project area is excellent year-round via logging and fire control roads maintained by the forest service or the timber industry. Likewise, numerous potential drill-site locations have been constructed as timber recovery staging areas and may be available to be utilized in the initial testing phase of the drilling program. In April 2007, we commenced drilling a stratigraphic/information hole exploration project. One well and two surface holes were drilled before financial constraints caused suspension of operation activities.

Natural Gas Market

Our Chehalis Basin project area is located within close proximity to the Interstate 5 corridor that parallels the route of the principal interstate pipeline providing natural gas to utility, commercial and industrial customers in Washington and Oregon. With anticipated declines in Canadian-sourced natural gas, we believe that robust markets will exist for gas produced from the Chehalis Basin. Because of its west coast location and ready connection to a major interstate pipeline, Chehalis Basin market prices would be subject to pricing standards of the New York Mercantile Exchange for most of the year. Regional gas pricing hubs are located at Malin and Stanfield, Oregon. However, seasonal or critical gas demand fluctuations could cause prices to exceed or fall below posted prices on a regular basis.

Exploration Objectives

The Chehalis Basin is located towards the northern end of a series of sedimentary basins that are present in Oregon and Washington west of the Cascade Range. The region containing this series of basins is generally referred to as the Puget-Willamette Trough. These basins contain thick sequences of predominantly non-marine, coal-bearing sedimentary rock sequences that are correlative in age, closely related in genesis, and very similar in many characteristics. Cascadia Energy Corp. is primarily targeting natural gas from coal seams of the Cowlitz Formation in the Chehalis Basin. Secondary objectives are natural gas, and possibly oil, trapped in conventional sandstone reservoirs.

Indications of the hydrocarbon potential in the Puget-Willamette Trough are shown by natural gas production at the Mist Field in northwest Oregon, the presence of excellent quality sand reservoir development at the Jackson Prairie Gas Storage Field in southwest Washington, and numerous oil and/or gas shows from historic oil and gas exploration drilling activity.

The Coalbed Methane Industry

During the past two decades, coalbed methane has emerged as a viable source of natural gas compared to the late 1980s when no significant production outside of the still dominant San Juan Basin in New Mexico, and the Black Warrior Basin in Alabama. According to data from the U.S. Department of Energy's Energy Information Administration, coalbed methane production totaled 1.72 trillion cubic feet in 2004, an increase of 7.5% over 2003. This production accounted for nearly 9% of the country's total dry-gas output of 19.7 trillion cubic feet. Coalbed methane production currently comes from fifteen basins located in the Rocky Mountain, Mid-Continent and Appalachian regions. Various evaluation, exploration and development projects are underway in at least four other basins, including Coos Bay and Chehalis basins. One of the coalbed methane industry's leading information specialists estimates that the number of producing wells nationwide (including those close to achieving production) is approaching 35,000. By comparison, more than 405,000 wells produce natural gas nationwide. However, none of this production of natural gas currently comes from Oregon or Washington. All of the natural gas presently consumed in the Pacific Northwest must be delivered by interstate pipelines from Western Canada and Wyoming.

We believe the success of coalbed methane developments has largely been the result of improved drilling and completion techniques (including horizontal/lateral completions), better hydraulic fracture designs and significant cost reductions as a result of highly dependable gas content and coalbed reservoir performance analysis. Also aiding this sector's growth is the apparent shortage of quality domestic conventional exploration and development projects.

We also believe that a major factor driving the growth in coalbed methane production is its relatively low finding and development costs. Coalbed methane fields are often found where deeper conventional oil and gas reservoirs have already been developed. Therefore, considerable exploration-cost reducing geologic information is often readily available. This available geological information, combined with comparatively shallow depths of prospective coalbed reservoirs, reduces finding and development costs.

A number of government agencies and industry organizations use various statistical methodologies to estimate the volume of potentially recoverable coalbed methane using currently available technology and specific economic conditions. The Potential Gas Committee, which provides the most frequent assessments of the country's natural gas resource base, estimates technically recoverable coalbed methane resources of 106.5 trillion cubic feet for the Lower 48 States as of year end 2004. This represents approximately 15% of the total estimated in-place coalbed methane resource of 700 trillion cubic feet. It is important to note that technically recoverable gas volumes do not necessarily qualify as proved reserves, and we have not recorded any proved reserves at our projects in Oregon or Washington at this time.

Coalbed Methane

Natural gas normally consists of 80% or more methane with the balance comprising such hydrocarbons as butane, ethane and propane. In some cases it may contain minute quantities of hydrogen sulfide, referred to as sour gas.

Coalbed methane is, generally, a sweet gas consisting of 95% methane which would normally be considered pipeline quality. Coalbed methane is considered an unconventional natural gas resource because it does not rely on conventional trapping mechanisms, such as a fault or anticline, or stratigraphic traps. Instead coalbed methane is absorbed or attached to the molecular structure of the coals which is an efficient storage mechanism as coalbed methane coals can contain as much as seven times the amount of gas typically stored in a conventional natural gas reservoir such as sandstone or shale. The absorbed coalbed methane is kept in place as a result of pressure equilibrium often from the presence of water. Thus the production of coalbed methane in many cases requires the dewatering of the coals to be exploited. This process usually requires the drilling of adjacent wells and sometimes takes 6 to 36 months to complete. Coalbed methane production typically has a low rate of production decline and an economic life a typical well can be 10 to 20 years and the economic life of a typical field can be 30 to 50 years,

The principal sources of coalbed methane are either biogenic, producing a dry gas which is generated from bacteria in organic matter, typically at depths less than 1,000 feet, or thermogenic, which is a deeper wet gas formed when organic matter is broken down by temperature and pressure.

The three main factors that determine whether or not gas can be economically recovered from coalbeds are: (1) the gas content of the coals; (2) the permeability or flow characteristics of the coals; and (3) the thickness of the coalbeds. Gas content is measured in terms of standard cubic feet per ton and varies widely from 430 standard cubic feet per ton in the deep (2,000 to 3,500 feet) San Juan, New Mexico thermogenic coals, and only 60 standard cubic feet per ton for the shallow (300 to 700 feet deep) Powder River, Wyoming biogenic coals. The San Juan coals are considered to have the industry's highest permeability. Relatively high permeability, which can affect the ability of gas to easily travel to the borehole, is an important factor for the success of coalbed methane wells, but is not absolutely required. The thickness of coalbeds from which coalbed methane is economically produced varies from as little as a few feet in some areas of the gas-rich (300 standard cubic feet) Raton Basin to as much as 75 net feet of coalbed thickness at the relatively gas-poor Powder River Basin.

Competition

Coalbed methane in the United States is produced by several major exploration and production companies and by numerous independents. The majors include BP American and ConocoPhillips in the San Juan Basin and, to a lesser extent, Chevron USA in the Black Warrior Basin. A number of large and mid-size independents, including Anadarko Petroleum Corporation, CMS Energy Corporation, CNX Gas Corporation, Devon Energy Corporation, Dominion Resources, Inc., El Paso Corporation, EnCana Corporation, Energen Corporation, Equitable Resources, Inc., Fidelity Exploration & Production Company, GeoMet Inc., J.M. Huber Corporation, Lance Oil & Gas Corporation, Penn Virginia Corporation, Pennaco Energy Inc., Pioneer Natural Resources Company, The Williams Companies, Inc., XTO Energy Inc. and Yates Petroleum Corporation, have established production in one or more basins. Dozens of smaller independents, many of whom originally began with conventional oil and gas production and operating a small number of wells, have found profitable niches in coalbed methane. Other new entrants to coalbed methane continue to acquire prospective acreage and to conduct test drilling. By virtue of their strategic property holdings, affiliates of several of the country's largest coal mining companies also have become active in coalbed methane, such as Consol Energy Inc., Jim Walter Resources, Inc., Peabody Energy Corporation, USX Corporation and Westmoreland Coal Company. In the Cascadia prospect area, Citrus Energy, LLC. and Venaco Energy, Inc. represent competitors to Cascadia Energy Corp.

Government Regulation

Our oil and gas operations are subject to various United States federal, state and local governmental regulations. Matters subject to regulation include drilling and discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells, pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. The production, handling, storage, transportation and disposal of oil and gas, by-products thereof, and other substances and materials produced or used in connection with oil and gas operations are also subject to regulation under federal, state, and local laws and regulations relating primarily to conservation and the protection of human health and the environment. To date, expenditures related to complying with these laws, and for remediation of existing environmental contamination, have not been significant in relation to the results of operations of our Company. The requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Employees

As of July 11, 2008, we had four non-union, full time employees, of which two are executives. We consider our relations with our employees to be good.

ITEM 1A. RISK FACTORS

Much of the information included in this annual report includes or is based upon estimates, projections or other "forward-looking statements." Such forward-looking statements include any projections or estimates made by us and our management in connection with our business operations. These include (i) continued availability of funds pursuant to the DIP Credit Agreement , (ii) the potential prospective for coalbed methane and conventional natural gas production in the Coos Bay Basin and the Chehalis Basin, (iii) the potential pipeline capacity in the port of Coos Bay area, and (iv) greater market for natural gas in Coos County and the Pacific Northwest region in general. Although these forward-looking statements, and any assumptions upon which they are based, are made in good faith and reflect our current judgment regarding the direction of our business, actual results will almost always vary, sometimes materially, from any estimates, predictions, projections, assumptions, or other future performance suggested herein. We undertake no obligation to update forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Such estimates, projections or other "forward-looking statements" involve various risks and uncertainties as outlined below. We caution readers of this annual report that important factors in some cases have affected and, in the future, could materially affect actual results and cause actual results to differ materially from the results expressed in any such estimates, projections or other "forward-looking statements." In evaluating us, our business and any investment in our business, readers should carefully consider the following factors.

We face significant challenges in connection with our bankruptcy reorganization.

On June 2, 2008, the Company and its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. We are currently operating our businesses as debtors-in-possession pursuant to the Bankruptcy Code.

On June 16, 2008, we filed the Plan with the Bankruptcy Court, which will consider whether to confirm the Plan. The Plan may not receive the requisite acceptance by creditors, equity holders and other parties in interest, and the Bankruptcy Court may not confirm the Plan. Moreover, even if the Plan receives the requisite acceptance by creditors, equity holders and parties in interest and is approved by the Bankruptcy Court, the Plan may not be viable.

In addition, due to the nature of the reorganization process, creditors and other parties in interest may take actions that may have the effect of preventing or unduly delaying confirmation of the Plan. Accordingly, we provide no assurance as to whether or when the Plan may be confirmed in the Chapter 11 process.

We face uncertainty regarding the adequacy of our capital resources and have limited access to additional financing.

We are currently operating under a $4.5 million debtors-in-possession financing facility. The DIP Credit Agreement contains certain highly restrictive covenants which require us, among other things, to maintain our corporate existence, make certain payments, perform our obligations under existing agreements, purchase insurance and provide financial records, and which limit or prohibit our ability to incur indebtedness, make prepayments on or purchase indebtedness in whole or in part, pay dividends, make investments, lease properties, create liens, consolidate or merge with another entity or allow one of our subsidiaries to do so, sell assets, and acquire facilities or other businesses.

We do not assure you that we will be able to consistently comply with these and other restrictive covenants in our DIP Credit Agreement. Furthermore, any advances under the DIP Credit Agreement are at the discretion of the DIP lender, and we have no control over its decision to provide any additional financing.

In addition to the cash requirements necessary to fund ongoing operations, we anticipate that we will incur significant professional fees and other restructuring costs in connection with the Chapter 11 process and the restructuring of our business operations. We do not assure you that the amounts of cash available from our DIP Credit Agreement will be sufficient to fund operations until the Plan receives the requisite acceptance by creditors, equity holders and parties in interest and is confirmed by the Bankruptcy Court. If available borrowings under the DIP Credit Agreement are not sufficient to meet our cash requirements, we may be required to seek additional financing. We can provide no assurance that additional financing would be available or, if available, offered on acceptable terms.

As a result of the Chapter 11 process and the circumstances leading to the Chapter 11 Cases, our access to additional financing is, and for the foreseeable future will likely continue to be, very limited. Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and ultimately cannot be determined until a plan of reorganization has been developed and is confirmed by the Bankruptcy Court in the Chapter 11 process.

We are subject to restrictions on the conduct of our business.

We are operating our businesses as debtors-in-possession pursuant to the Bankruptcy Code. Under applicable bankruptcy law, during the pendency of the Chapter 11 process, we will be required to obtain the approval of the Bankruptcy Court prior to engaging in any transaction outside the ordinary course of business. In connection with any such approval, creditors and parties in interest may raise objections to approval of the action and may appear and be heard at any hearing with respect to the action. Accordingly, although we may sell assets and settle liabilities (including for amounts other than those reflected on our financial statements) with the approval of the Bankruptcy Court, we cannot assure you that the Bankruptcy Court will approve any sales or settlements proposed by us. The Bankruptcy Court also has the authority to oversee and exert control over our ordinary course operations.

In addition, the DIP Credit Agreement imposes on us numerous financial requirements and covenants. Failure to satisfy these requirements and covenants could result in an event of default that could cause, absent the receipt of appropriate waivers, an interruption in cash availability, which could cause an interruption of our normal operations.

As a result of the restrictions described above, our ability to respond to changing business and economic conditions may be significantly restricted and we may be prevented from engaging in transactions that might otherwise be considered beneficial to us.

Our financial statements assume we can continue as a “going concern” but our independent auditors have expressed substantial doubt about our ability to continue as a going concern, which may hinder our ability to obtain future financing.

In their report dated July 14, 2008, our independent auditors stated that our consolidated financial statements for the fiscal year ended March 31, 2008 were prepared assuming that we would continue as a going concern.

Our ability to continue as a going concern is an issue raised as a result of our Chapter 11 filings, recurring losses from operations and periodic working capital deficiencies. Our ability to continue as a going concern is subject to obtaining approval of our Plan and our ability to obtain necessary funding from outside sources, including obtaining additional funding from the sale of our securities. Our continued net operating losses increase the difficulty in meeting such goals and there can be no assurances that such funding methods will prove successful.

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In addition, because of the Chapter 11 proceedings and the circumstances leading to the Chapter 11 filings, it is possible that we may not be able to continue as a "going concern." Our continuation as a "going concern" is dependent upon, among other things, confirmation of the Plan, our ability to comply with the terms of the DIP Credit Agreement, our ability to obtain financing upon exit from bankruptcy and our ability to generate sufficient cash from operations to meet our obligations.

Should we fail to be a going concern, then significant adjustments would be necessary in the carrying value of assets and liabilities, the revenues and expenses reported and the balance sheet classifications used.

In addition, the amounts reported in the consolidated financial statements included in this annual report do not reflect adjustments to the carrying value of assets or the amount and classification of liabilities that ultimately may be necessary as the result of our reorganization under Chapter 11. Adjustments necessitated by the Plan could materially change the amounts reported in the consolidated financial statements included in this Annual Report.

Our successful reorganization will depend on our ability to retain key employees and successfully implement new strategies.

Our success depends to a significant extent upon the continued service of Mr. John Carlson, who is our President and Chief Executive officer, and sole director. Loss of the services of Mr. Carlson could have a material adverse effect on our growth, revenues, and prospective business. We do not maintain key-man insurance on the life of Mr. Carlson. In addition the successful implementation of our business plan and our ability to successfully consummate a plan of reorganization will be highly dependent upon our senior management. Our ability to attract, motivate and retain key employees is restricted by provisions of the Bankruptcy Code, which limit or prevent our ability to implement a retention program or take other measures intended to motivate key employees to remain with us during the pendency of the bankruptcy cases. The loss of the services of key personnel could have a material adverse effect upon the implementation of our business plan, including our restructuring program, and on our ability to successfully reorganize and emerge from bankruptcy.

We have a history of losses that may continue, which may negatively impact our ability to achieve our business objectives.

We have accumulated a deficit of $26,132,279 to March 31, 2008 and incurred net losses applicable to common shareholders of $9,486,503 for the fiscal year ended March 31, 2008; and $7,765,427 for the fiscal year ended March 31, 2007. We do not assure you that we can achieve or sustain profitability on a quarterly or annual basis in the future. Our operations are subject to the risks and competition inherent in the establishment of a business enterprise. There is no assurance that future operations will be profitable. We may not achieve our business objectives and the failure to achieve such goals would have an adverse impact on us.

If we are unable to obtain additional funding, our business operations will be harmed; and if we do obtain additional financing, our then existing shareholders may suffer substantial dilution.

We will require additional funds to sustain and expand our oil and gas exploration activities. We anticipate that we will require up to approximately $7,000,000 to fund our continued operations for the fiscal year ending March 31, 2009. Additional capital will be required to effectively support our operations and to implement our business strategy. There can be no assurance that financing will be available in amounts or on terms acceptable to us, if at all. The inability to obtain additional capital will restrict our ability to grow and inhibit our ability to continue to conduct business operations. If we are unable to obtain additional financing, we will likely be required to curtail our exploration plans and possibly cease our operations. Any additional equity financing may result in substantial dilution to our then existing shareholders.

We have a limited operating history and if we are not successful in continuing to grow our business, then we may have to scale back or even cease our ongoing business operations.

We have a limited operating history in the business of oil and gas exploration and must be considered to be an exploration stage company. We have no history of revenues from operations and have no significant tangible assets.