

Form 51-101 F1

LNG Energy Ltd.

Statement of Reserves Data

And Other Oil and Gas Information

As of September 30, 2010

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Glossary of Terms

Reserves	Estimated reserves of natural gas, natural gas liquids and crude oil.
Working interest	Those lands in which the Company receives its acreage share of net production revenues.
Gross reserves	Estimated reserves before royalties based on working interest.
Net reserves	Estimated reserves after royalties based on working interest.
Future net revenue	Working interest revenues after royalties, development costs, production costs and well abandonment costs, but before administrative, overhead and other such indirect costs. Future net revenue may be presented either before or after tax.
Proved reserve	Reserve that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
Probable reserves	Reserve that is less certain than proved reserve at being recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserve.
Developed reserve	Reserve that is expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.
Producing reserve	Reserve that is expected to be recovered from completion intervals open at the time of estimate. The category of reserve may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
Non-prod. reserve	Reserve that either has not been on production, or has previously been on production, but is shut-in, and the date of resumption of production is unknown.
Stb/stock tank barrel	A 42-US gallon barrel of crude oil at standard conditions of 1 atmosphere and 60 °F.
M	Thousand (1,000).
Mbbl	1,000 barrels of oil and/or natural gas liquids.
MMBtu	A unit of heat energy equal to one million British thermal units.
Mcf	1,000 cubic feet of natural gas.
Bcf	One billion (1,000,000,000) cubic feet of natural gas
bbl or barrel	A 42-US gallon barrel of crude oil or natural gas liquids.
Undeveloped reserve	Reserve that is expected to be recovered from known accumulation where a significant expenditure is required to render them capable of production (e.g. in comparison to the costs of drilling a well). Such reserve must fully meet the requirements of the reserve classification to which they are assigned (proved or probable).

Form 51-101 F1**Statement of Reserves Data and Other Oil and Gas Information for LNG Energy Ltd.****Part 1 Date of Statement**

Date of Statement: January 25, 2011
Effective Date: September 30, 2010
Preparation Date: November 22, 2010

The following information is related to LNG Energy Ltd. (the “Reporting Issuer”) future net revenue and discounted value of future net cash flow of natural gas and condensate. MHA Petroleum Consultants LLC (“MHA”), independent qualified evaluators of Lakewood estimated these reserves effective September 30, 2010. The Company used these reserves in the preparation of our Financial Statements for the fiscal year ended September 30, 2010.

All of the Company’s oil and gas reserves are onshore in the country of United States of America.

The reserves on the properties described herein are estimates only. Actual reserves on our properties may be greater or less than those calculated.

The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves. There is no assurance that forecast prices and costs assumed in the MHA evaluation will be attained, and variances could be material. Assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables.

The following tables provide reserves data and a breakdown of future net revenue by commodity and reserve category using constant and forecast prices and costs, based on the Company’s working interest portion before royalties (gross) and/or after royalties (net) (see “Glossary of Terms”).

The pricing used in tables that reflect forecast price evaluations is set forth in Items 3.1 and 3.2. All cash flow data is in U.S. dollars unless stated otherwise.

In certain instances, numbers may not total due to computer-generated rounding. In such cases, differences are not material and amounts presented are as shown in the MHA Report.

Part 2 Disclosure of Reserves Data

Item 2.1 Reserves Data (Forecast Prices and Costs)

Item 2.1.1 Breakdown of Reserves (Forecast Case)

Onshore U.S.A.	Gas		Oil		NGLs		TOTAL	
	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Reserve Category								
Proved developed producing	4,394.4	173.2	71.5	4.3	540.4	30.4	1,344.3	63.6
Proved undeveloped	16,391.9	4,195.0	316.4	115.7	2,016.2	737.1	5,064.6	1,552.0
Total Proved	20,786.3	4,368.2	387.9	120.0	2,556.6	767.5	6,480.9	1,615.6
Probable	26,227.1	4,371.2	506.2	120.5	3,225.9	768.1	8,103.3	1,617.1
Total Proved plus Probable (2P)	47,013.4	8,739.4	894.1	240.5	5,782.5	1,535.6	14,512.2	3,232.7
Possible	32,783.8	8,727.3	632.7	240.6	4,032.4	1,533.5	10,129.1	3,228.7
Total Proved plus Probable plus Possible (3P)	79,797.2	17,466.7	1,526.8	481.1	9,814.9	3,069.1	24,641.2	6,461.4

Item 2.1.2 Net Present Value of Future Net Revenue (Forecast Case)

Onshore U. S. A.	Before Income Tax Present Value Discounted @					Unit Value based on Discount @ 10%
	0%	5%	10%	15%	20%	
Reserve Category	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	\$/Boe
Proved developed producing	1,153.5	702.6	509.5	405.7	341.1	8.01
Proved undeveloped	36,044.1	25,317.2	18,053.8	12,967.3	9,298.2	11.63
Total Proved	37,197.6	26,019.8	18,563.3	13,373.0	9,639.3	11.49
Probable	40,503.2	27,153.1	18,602.5	12,922.2	9,027.1	11.50
Total Proved plus Probable	77,700.8	53,172.9	37,165.8	26,295.2	18,666.4	11.50
Possible	95,771.1	53,594.1	31,008.7	18,421.5	11,164.5	9.60
Total Proved, Probable plus Possible	173,471.9	106,767.0	68,174.5	44,716.7	29,830.9	10.55

Onshore U. S. A.	After Income Tax Present Value Discounted @					Unit Value based on Discount @ 10%
	0%	5%	10%	15%	20%	
Reserve Category	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	(M\$ U.S.)	\$/Boe
Proved developed producing	742.5	455.7	330.5	263.0	220.8	5.20
Proved undeveloped	23,324.6	15,738.8	10,582.4	6,964.7	4,355.3	6.82
Total Proved	24,067.1	16,194.5	10,912.9	7,227.7	4,576.1	6.75
Probable	26,216.2	16,889.3	10,923.5	6,976.8	4,289.6	6.75
Total Proved Plus Probable	50,283.3	33,083.8	21,836.4	14,204.5	8,865.7	6.75
Possible	62,015.3	33,564.3	18,555.5	10,365.7	5,775.0	5.75
Total Proved, Probable plus Probable	112,298.6	66,648.1	40,391.9	24,570.2	14,640.7	6.25

Item 2.1.3 Additional Information Concerning Future Net Revenue (Forecast Case)

Onshore, U.S.A.	Revenue	Severance Taxes	Operating Costs	Development Costs	Well Abandonment Costs (1)	Future Net Revenue Before Income Tax	Future Income Tax Expenses	Future Net Revenue After Income Tax
<u>Reserve Category</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>	<u>(M\$ U.S.)</u>
Total Proved	63,130	2,284	8,985	14,664	318	37,198	13,131	24,067
Total Proved plus Probable	128,719	4,483	16,261	30,273	635	77,701	27,418	50,283
Total Proved, Probable plus Possible	277,150	9,278	30,501	63,899	1,309	173,472	61,173	112,299

Unit Value based on
Discount @ 10%

<u>Reserve Category</u>	<u>(\$/Boe)</u>
Total Proved	11.49
Total Proved plus Probable	11.50
Total Proved, Probable plus Possible	10.55

Item 2.2 Supplemental Disclosure of Reserves Data (Constant Prices and Costs)

Not applicable.

Item 2.3 Reserves Disclosure Varies with Accounting

Not applicable.

Item 2.4 Future Net Revenue Disclosure Varies with Accounting

Not applicable.

Part 3 Pricing Assumptions**Item 3.1 Constant Prices Used in Estimates**

Not applicable.

Item 3.2 Forecast Prices Used in Estimates

Item 3.2.1 (a)

The historical oil and gas prices were taken from Sproule and Associates Inc (www.sproule.com). The forecast prices are as follows:

Year	WTI, \$/bbl	NGL \$/bbl	Henry Hub, \$/Mmbtu
2010	75.60	28.73	4.12
2011	80.57	30.62	4.63
2012	83.76	31.83	5.22
2013	86.09	32.71	5.72
2014	90.22	34.28	6.63
2015	91.57	34.80	7.54
2016	92.64	35.32	8.20
2017	94.34	35.85	8.32
2018	95.75	36.39	8.45
2019	97.19	36.93	8.58
2020	98.65	37.49	8.70

Escalation Rate of 2.0% thereafter

(1) All prices are listed in U.S. dollars.

Item 3.2.1(b) Not applicable.

Item 3.2.2 Not applicable.

Item 3.2.3 Not applicable.

Part 4 Reconciliations of Changes in Reserves

Item 4.1 Reserves Reconciliation

Reconciliation of Company Gross Reserves by Principle Product Type

	Natural Gas			Oil			NGL's			TOTAL		
	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
Sept 30, 2009	24,656	34,731	59,387	455	645	1,100	3,335	4,689	8,024	7,899	11,123	19,022
Extensions												
Improved Recovery												
Technical Revisions												
Discoveries												
Acquisitions												
Dispositions												
Economic Factors	(3,851)	(8,504)	(12,355)	(66)	(139)	(205)	(775)	(1,463)	(2,238)	(1,483)	(3,019)	(4,502)
Production	(19)		(19)	(1)		(1)	(3)		(3)	(7)		(7)
Sept 30, 2010	20,786	26,227	47,013	388	506	894	2,557	3,226	5,783	6,409	8,104	14,513

Part 5 Additional Information Relating to Reserves Data

Item 5.1 Undeveloped Reserves

The Company's proved undeveloped reserves exist in the West Tishomingo field in Oklahoma, US. Plans for the future development of these undeveloped reserves (based on Forecast Prices) are summarized below:

United States of America Properties

West Tishomingo Field, Oklahoma

Volumes of proved undeveloped reserves

Year	Natural Gas (Mmcf)	Oil (Mbbbl)	NGL (Mmcf)
2010	4,195.0	115.7	737.1
2009	5,340.0	147.2	1,029.9
2008	-	-	-

MHA assigns 5,255.7Mboe Net Proved Undeveloped reserves to the West Tishomingo field. The production forecast is based on producing the existing wells, and drilling an additional 5 gross wells and applying the historical production behavior to the undeveloped wells locations. Probabilistic reserves were determined from Monte Carlo analysis to arrive at the most like reserves and incremental (P50) reserves

The Proved Undeveloped Reserves are based upon drilling two, one and two wells in 2011, 2012 and 2013, respectively. Well spacing is currently forecasted and scheduled at 2 wells per section (640 acres).

Volumes of probable undeveloped reserves

Year	Natural Gas (Mmcf)	Oil (Mbbbl)	NGL (Mmcf)
2010	4,371.2	120.5	768.1
2009	5,624.0	153.4	1,084.6
2008	-	-	-

The Probable Undeveloped Reserves are based upon drilling two, one, three and two wells in 2012, 2013, 2014 and 2015, respectively. Well spacing is currently forecasted and scheduled at 2 wells per section (640 acres).

Item 5.2 Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgements and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices, and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performances, prices, economic conditions, and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance, and geologic conditions or production. These revisions can be either positive or negative.

Item 5.3 Future Development Costs

A summary of the estimated develop costs deducted in the estimation of future net revenue attributable to various reserves categories and prepared under various price and cost assumptions are summarized below. The Company expects to fund its estimated future develop costs through some combination of equity and debt financing. There can be no guarantee that funds will be available or that the Board of Directors of the Company will allocate funding to develop all of the reserves requiring development. Failure to develop such reserves could negatively impact future net revenue.

Future Development Costs

Year	Proved Reserves (M\$)	Proved + Probable Reserves (M\$)
2011	8,402	16,908
2012	5,944	5,944
2013	318	7,421
TOTAL	14,664	30,273

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

West Tishomingo, Oklahoma (onshore)

On December 4th, 2008, the Company acquired a 60% interest in a private company, BWB Exploration, LLC. (“BWB”), where BWB holds interests in approximately 3,299 acres of oil and gas leases which are in the West Tishomingo Field development, in Carter County, Oklahoma.

BWB participated in a well drilling program with XTO Energy Inc. (“XTO”) as the operator of the Berwyn #1-15H well (“Berwyn”) within the West Tishomingo region. The total cost paid by the private company for a 7.86% participation right was US\$505,585. Production for this well commenced in late March 2009.

BWB has completed all legal regulatory submissions to the Oklahoma Corporate Commission to become the recognized operator to drill the offsetting two sections to the south (Sections 21 and 22).

Item 6.1.2 Gross and net oil and gas wells:

West Tishomingo, Oklahoma (onshore), U.S.A.

<u>County</u>	Producing Wells				Non-Producing Wells			
	Oil Wells		Gas Well		Oil Wells		Gas Wells	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Ardmore	-	-	1	.080	-	-	-	-
Carter	-	-	1	.007	-	-	-	-
Total	-	-	2	.087	-	-	-	-

Item 6.2 Properties with No Attributed Reserves

Black Warrior Basin, Alabama (Onshore)

On December 4, 2008, the Company acquired a 60% interest in a private company, BWB Exploration, LLC. (“BWB”), where BWB holds interests in 86,081 acres of oil and gas leases in the Black Warrior Basin of Alabama. The total expenditures related to Black Warrior Basin as at September 30, 2010 were US\$8,787,233 which includes an original purchase price allocation of US\$8,332,145 relating to the initial acquisition of BWB by the Company. The leases in Pickens County have an expiry range between 1 to 3 years with the latest expiring in 2013.

BNK Petroleum Inc. has entered into an Exploration Agreement with BWB in regard to the Black Warrior acreage whereby BNK can earn up to a 50% working interest in a portion or all of the Black Warrior acreage by drilling a series of test wells on identified prospects. The exploration program requires BNK to pay for BWB's share of costs in an eight well test program. BNK is currently projected to incur an expenditure of up to US\$10 million in the eight well program in order to earn the 50% working interest. BNK is committed to drill three wells, the first of which was spudded by September 30th, 2009. Failure to commence any of these three wells on scheduled dates subjects BNK to liquidated damages of \$500,000 per well.

In September 2009 BNK drilled its first well, the Hickman Farms 30-15 to a total depth of 5,475ft. Four zones were subsequently tested in the well unsuccessfully and the well was plugged and abandoned in July, 2010. BNK air drilled the WS Lee 26-12 again targeting the Pottsville tight gas sands in July 2010. This well reached a total depth of 8,011ft on July 24, 2010 and well logs suggest three potentials zones for testing but completion testing has not yet commenced. Each of the wells after the first well must commence within 90 days after the release of the completion rig on the previous well or BNK is subject to liquidated damages of \$500,000 per well in favour of BWB.

Papua New Guinea (Onshore)

On November 27, 2007, the Company acquired 90% interest in LNG Energy (B.C.) Ltd (“LNG BC”) formerly Cheetah Oil & Gas Limited (British Columbia). LNG BC indirectly holds interest in the following Petroleum Prospecting License’s (PPL) through permits received from the Minister of Petroleum and Energy for Papua New Guinea.

On November 25, 2008, the Company purchased the remaining 10% interest of LNG BC, making LNG BC a wholly-owned subsidiary of the Company.

On November 20, 2008, the Company received approval of its top file applications that were filed with the PNG Department of Petroleum and Energy. This relates to its PPLs where the top file process involved the relinquishment of and the re-application of PPLs 245, 246, 249 and 252. PPL 250 was relinquished and was not renewed. Petroleum Retention License 13 (“PRL13”) remains the same. During the year, the Company acquired High Resolution Airborne Magnetic (“HRAM”) and Gravity data over its licenses in Papua New Guinea. This consisted of a fixed-wing acquisition of a high resolution survey at a minimum drape altitude of 150m, with an 800m normal traverse and 1600m control line spacing. In-field Quality Control and Project Management was provided by Erwin Ebner of ELS Consulting Inc. out of Calgary, Alberta. Integrated Geophysics Corporation (“IGC”) of Houston, Texas (<http://igcworld.com>) was contracted to interpret the HRAM and Gravity dataset. IGC’s proprietary analysis incorporates existing seismic, wells and all available surface geological control with the recently acquired HRAM and Gravity dataset, to provide a comprehensive and fully integrated interpretation.

The methodology of integrating all available historical exploration data, with LNG's recent HRAM & Gravity survey, was repeated within the three northern PPLs; 320, 321 and 322. The HRAM & Gravity surveys are now complete. The northern PPLs are comprised of multiple tertiary aged basins that are known to contain active hydrocarbon seeps, while also being highly prospective for both the carbonate and sandstone reservoirs that outcrop at basin edges.

Original License	Top Filed License	Blocks	Expiration date	Company's W.I. (1)	Total
PPL #13	PPL #13	2	January 27, 2011	100.00%	40,031
PPL #246	PPL #319	25	November 19, 2014	100.00%	500,388
PPL #245	PPL #322	97	November 19, 2014	100.00%	1,941,504
PPL #249	PPL #320	58	November 19, 2014	100.00%	1,160,899
PPL #252	PPL #321	92	November 19, 2014	100.00%	1,841,426
Total		274			5,484,248

(1) Working Interest (W.I.)

The exploration properties are located in Southeastern Papua New Guinea in the Papuan Basin approximately 30 km southeast of the Southeastern Gobe oil and gas field. The Papua New Guinea Government has the option to take a 22.5% interest in the project. There is a 2% State Royalty rate and an income tax rate of; 30% for gas and 45% for oil, on the interest.

PRL 13 and PPL319

The PRL 13 license term is from January 28, 2010 to January 27, 2011 while the PPL license term is from November 20, 2008 to November 19, 2014. The total expenditures on PRL 13 were \$16,870,293 to date (from 2005 to September 30, 2010). The total expenditures on PPL 319 were \$6,469,358 as at September 30, 2010.

PPL 319's area, comprising of 25 blocks, is 2,025 km² (500,388 acres). PPL 319 is divided into three main zones, separated by major faults, and each with different stratigraphy. PPL 319 lies towards the eastern end of the oil and gas producing fold belt in PNG, approximately 30 km southeast of the Southeast Gobe oil and gas field. The area has long been known for its gas seeps and nearby oil-impregnated limestone that outcrops in the Irou structure, 24 km to the northeast. Four wells have been drilled in the PRL 13 license area, all completed in the 1950's and testing a near-surface Miocene (Darai) carbonate play; the overall results showed minimal prospectivity. Several wells drilled immediately to the north and west of the license indicate prospectivity for the licensed area. Geologically, the Papua fold and thrust belt was formed in the Late Miocene to Pliocene and is thought to mainly comprise break-thrust structures. Notably, the PPL 319 license lies mainly within the inversion belt, at the junction with and on strike with the NW-SE trending fold belt to the north, Aure Trough to the east and Gulf of Panama to the south.

PPL 322

The license term is from November 20, 2008 to November 19, 2014. The area, comprising 97 blocks, is 7,857 km² (1,941,504 acres). The total expenditures were \$1,703,956 as at September 30, 2010.

PPL 322, in northwestern Papua New Guinea (PNG), covers the easternmost Aitape Basin and the Wewak Trough, as well as the northeastern Sepik Basin. Neither of the basins has a proven record of commercial hydrocarbon production though light oil seeps with associated thermogenic gas indicate

prospectivity for both oil and gas. The analysis of available data in the form of geological maps and previous exploration reports defined three exploration leads in the license areas. The Wapa'Alua Anticline is a structural lead prospective for oil and gas just to the east of the Barida structure in PPL 322. In both the Matapau and Forok leads, which are located around persistent oil seepages, a mature source system has been proven. The risk in this area is whether there is adequate presence of reservoir below the thrust sheets.

PPL 320

The license term is from November 20, 2008 to November 19, 2014. The area, comprising 58 blocks, is 4,698 km² (1,160,899 acres). The total expenditures were \$1,161,204 as at September 30, 2010.

PPL 320 is in northwestern PNG in the Aitape Basin, which has no proven commercial production. Light oil seeps outside the block southeast of Aitape and thermogenic gas seeps within the block indicate prospectivity for both oil and gas. Three exploration wells drilled on a sparse seismic grid in the early 1980's proved the presence of Miocene Puwani limestone with reef debris and talus in the subsurface, but no in situ reef reservoirs have been positively identified. Fractured carbonates present a second potential reservoir objective within the block. Seismic interpretation of 422 km of 2D data, stratigraphic analysis and four structural cross-sections have provided mapping and documentation of thirteen exploration and notional leads. The Pinyare and Barida Anticlines are structural leads with potential resource of 425 MM barrels of mean unrisks light oil in place and are located in the jungle foothills in eastern PPL 320. The Muru Anticline is a structural lead prospective for gas in western PPL 320; it has potential for 614 Bcf unrisks gas-in-place.

PPL 321

The license term is from November 20, 2008 to November 19, 2014. The area, comprising 92 blocks, is 7,452 km² (1,841,422 acres). The total expenditures were \$1,024,122 as at September 30, 2010.

PPL 321 is prospective for biogenic dry gas in the shallow reservoirs (Plio-Pleistocene) and thermogenic wet gas or oil in deeper reservoirs (Miocene), as in gas fields in the Gulf of Mexico, USA. Furthermore, methane to pentane (C1-C5) gas is found in Keram-1 Miocene and Pliocene sandstone and Miocene carbonates. Finally, there is potential for both stratigraphic and structural plays, reservoirs and seals. The general conclusion to date is that the risk of hydrocarbon generation is relatively low when compared to trap risk. The high trap risk is predicated upon four previously drilled wells within the license, which have proved no hydrocarbons.

Poland

The Company holds a 20% interest in three concessions (Slupsk, Starogard and Slawno) held by its 20% owned subsidiary, Saponis Investments SP. z.o.o. License commitments will require the Company to finance its proportionate share of the drilling and testing of one exploration well per concession before the end of June 2011.

This opportunity is primarily targeting an Ordovician/Silurian aged resource play within the Baltic Basin, consisting of gas shales with a minimum gross thickness of 1000 ft (300m) and a maximum gross thickness of 3300 ft (1100m) over all three concession areas. The resource presence is defined by wells that have been extensively cored (core intervals exceed 1000 m) for both scientific and exploration purposes by Polish research institutes over the last 50 years. Sampling of existing well cores has been completed, with testing having been initiated within laboratories familiar with characterizing US based

gas resource plays. Preliminary core test results and resource characterization have been extremely encouraging relative to known US shale gas arenas and have provided the technical rationale for participation.

Item 6.3 Forward Contracts

The Company has no forward sales contracts fixing the price of oil or natural gas.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company uses the industry's historical costs to estimate its abandonment and reclamation costs when available. If the representative comparison are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

As at September 30, 2010, the Company has a working interest of 7.8% and a 0.78% interest in two proven and producing wells. For all current and future abandonment and reclamation costs for the West Tishomingo Field, these costs were assumed equal to salvage value for wells which have reserves assigned.

Item 6.5 Tax Horizon

Canada: As of September 30, 2010, the Company has no revenue generating properties in Canada. LNG has available for deduction against future Canadian taxable income non-capital losses of approximately \$7.7 million.

United States: The Company has approximately US\$10.7 million non-capital losses that can be carried forward to offset future US taxable income. The Company will be subject to a 35% federal and state income tax rate for fiscal years beginning in 2010.

Item 6.6 Costs Incurred

	<u>Acquisition Costs</u>		<u>Exploration</u>	<u>Development</u>
	Proved	Unproved		
<u>Onshore USA</u>				
	(\$ U.S.)	(\$ U.S.)	(\$ U.S.)	(\$ U.S.)
Oklahoma	635,341	2,152,382	1,339,603	0
Alabama	0	8,332,145	455,088	0
Asset Retirement Costs	0	3,119	0	0
Total	635,341	10,487,646	1,794,691	0
<u>Onshore Papua New Guinea</u>				
PPL 13	-	-	15,822,917	-
PPL 319	-	-	6,060,670	-
PPL 320	-	-	1,207,571	-
PPL321	-	-	1,127,294	-
PPL 322	-	-	1,717,157	-
Total	-	-	25,935,609	-

Item 6.7 Exploration and Development Activities

During the year ended September 30, 2010, the Company participated in two well, Berwyn 1-15H, located in Carter County, Oklahoma that was operated by XTO Energy Inc. and Garden 1-32H, which was operated by Chesapeake Energy Corporation. The Company's working interest is 7.86% for Berwyn and 0.78% in Garden 1-32H. The Company did not drill any wells during the year.

Item 6.8 Production Estimates from October 1, 2010 to September 30, 2011

Summary of Production Estimates

Proved + Probable Reserves Case
For Year Ended September 30, 2011

	Oil (Bbls)	Natural Gas (Mcf)	NGL's (Bbls)	Company
				Total (BOE)
<hr/>				
United States				
West Tishomingo, OK	9,004	327,414	57,531	121,104

- (1) Net reserves are the gross reserves after deduction of royalties.
- (2) Forecast case estimate is the same for the future net proved production estimate for the financial year-ending September 30, 2011.
- (3) Production is expected to begin October 2010 from two planned wells resulting in 4 months of production estimates.

Item 6.9 Production History

The Company's historical production data, before deduction of royalties, for the period ended September 30, 2010 is presented below: (in Canadian Dollars)

Production History - Year Ended September 30, 2010

	Oil (Bbls)	Natural Gas (Mcf)	NGL's (Bbls)	Total (BOE)	Avg Price Received (\$/BOE)	Royalties Paid (\$/BOE)	Production Costs (\$/BOE)	Netback
Oklahoma	761	18,938	3,057	6,974	\$ 33.80	\$ 6.64	\$ 3.01	\$ 24.15