



**DIAZ RESOURCES LTD.**

**Annual Information Form**

**Year Ended  
December 31, 2006**

**April 2, 2007**

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SCHEDULE "A", Form 51-101F3, Report of Management and Directors on Oil and Gas Disclosure

SCHEDULE "B", Form 51-101F2, Report on Reserves Data by Independent Qualified Reserves

Evaluator or Auditor

SCHEDULE "C", Audit Committee Mandate

## ABBREVIATIONS

### Oil and Natural Gas Liquids

Bbl	barrels
Bopd	barrels of oil per day
BOE	barrels of oil or natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas (and not based on energy content or current prices)
BOEd	BOE per day
MBbl	thousand barrels
Mstb	thousand stock tank barrels
Mstbe	thousand stock tank barrels equivalent
NGLs	Natural Gas Liquids

### Natural Gas

McfGE	thousand cubic feet of gas equivalent (oil is equated to natural gas on the basis of 1 barrel = 6 Mcf)
Mcf	thousand cubic feet
MMbtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
GJd	gigajoule per day
Mcfd	thousand cubic feet per day
MMcfd	million cubic feet per day
psia	pounds per square inch absolute

### Other

M\$	thousands of dollars
MM\$	millions of dollars
3D	three dimensional
AFE	authorization for expenditure
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Cdn.	Canadian
NRI	net revenue interest
OPEC	Organization of the Petroleum Exporting Countries
W.I.	working interest

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

**BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

## FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, completion and tie-in of wells and capital expenditures and the timing thereof may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Diaz's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could effect Diaz's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website ([www.sedar.com](http://www.sedar.com)), at Diaz's website ([www.diazresources.com](http://www.diazresources.com)). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

## **BACKGROUND**

### **The Corporation**

Diaz Resources Ltd. ("Diaz") was incorporated under the laws of the Province of British Columbia on November 3, 1986 under the name "GMN The Gospel Music Network, Ltd." by registration of its Memorandum pursuant to the *Company Act* (British Columbia). Diaz changed its name on May 15, 1990, to "Your Host Foods Inc." and subsequently on June 1, 1994 changed its name to "Diaz Resources Ltd."

On April 14, 1998, Diaz was continued under the laws of the Province of Alberta and on May 6, 1998 the Articles of Diaz were amended to create a class of an unlimited number of Class A Subordinate Voting Shares and a class of an unlimited number of Class B Multiple Voting Shares. Every four common shares outstanding were changed to one Class A Subordinate Voting Share and one Class B Multiple Voting Share.

Pursuant to Articles of Amalgamation dated June 8, 1999, Brittany Energy Inc. ("Brittany"), Uniglobe Ventures Ltd. ("Uniglobe") and 825281 Alberta Ltd., a wholly owned subsidiary of Diaz, amalgamated and continued as one corporation, under the name "Diaz Energy Inc.", which continued to be a wholly-owned subsidiary of Diaz. Immediately thereafter, Diaz Energy Inc. was amalgamated with Diaz pursuant to Articles of Amalgamation dated June 8, 1999, and the amalgamated corporations continued under the name "Diaz Resources Ltd."

At its shareholders' meeting on June 9, 2005, the Corporation's shareholders approved an amendment to the Articles of the Corporation to change the outstanding Class A Subordinate Voting Shares and Class B Multiple Voting Shares into one class of common shares ("Common Shares"), on a one-for-one basis. As a result, the Corporation now has only one class of shares outstanding, being the Common Shares.

The head and principal office of Diaz is located at Suite 1800, 633 Sixth Avenue S.W., Calgary, Alberta, T2P 2Y5. The registered office of Diaz is Suite 1400, 350 Seventh Avenue S.W., Calgary, Alberta, T2P 3N9.

### **Subsidiaries**

Diaz has two wholly owned subsidiaries, Diaz Resources, Inc. and Orbit Oil & Gas Inc., each incorporated pursuant to the laws of the State of Delaware. Both of these companies are involved in oil and gas exploration and production in the United States, and are registered in the state of Texas.

Reference to "Diaz" or the "Corporation" herein means Diaz Resources Ltd. together with its wholly-owned subsidiaries, Diaz Resources, Inc. and Orbit Oil & Gas Inc., unless the context otherwise requires.

## **GENERAL DEVELOPMENT OF THE BUSINESS**

Diaz is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Western Canada and the United States.

Over the past three years Diaz has explored for natural gas in the United States through an informal joint venture agreement with Sharon Energy Ltd. The companies acquired land and seismic data

and jointly participated in drilling exploration wells in Texas. Sharon has also participated with Diaz in some of its Canadian exploration programs.

On March 27, 2007, Diaz completed a financing of 8.75% convertible unsecured subordinated debentures ("Debentures"). Debentures having an aggregate principal amount of \$7,085,000 were issued, of which, as of the date hereof, \$225,000 of the Debentures are being held in escrow subject to receipt of final subscriber documentation which is expected prior to April 16, 2007. Proceeds from the issuance of the Debentures will be used to finance Diaz's exploration and development program in Canada and the United States.

## DESCRIPTION OF THE BUSINESS AND OPERATIONS

Diaz is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Western Canada and the United States. The primary focus of Diaz is exploring for natural gas in southern Alberta and in Texas and exploring for oil in Saskatchewan. The following is a description of the Corporation's assets.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The effective date of the statement of reserves data and other oil and gas information set forth below (the "Statement") is December 31, 2006 and the preparation date of the Statement is March 15, 2007.

### Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by AJM Petroleum Consultants ("AJM") with an effective date of December 31, 2006 contained in a report of AJM dated March 15, 2007 (the "AJM Report"). The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms to the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and information which we believe is important to the readers of this information. The Corporation engaged AJM to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and the United States and, specifically, in the provinces of Alberta and Saskatchewan, in Canada and in the United States, in Texas.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves may be greater or less than the estimates provided herein.**

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by Independent Qualified Reserves Evaluator are attached as Schedule "A" and Schedule "B" hereto, respectively.

For the purpose of presentation in certain tables that follow, US dollar amounts in the AJM Report have been converted to Canadian dollars at a year end rate of \$0.88 US, unless otherwise stated.

**Reserves Data (Constant Prices and Costs)**

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

<u>COMPANY TOTAL</u>	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	198	175	-	-	7,397	6,060	24	17
Developed Non-producing	90	74	-	-	143	129	-	-
Undeveloped	0	0	-	-	5,909	5,119	13	9
<b>TOTAL PROVED</b>	<b>288</b>	<b>249</b>	<b>-</b>	<b>-</b>	<b>13,449</b>	<b>11,308</b>	<b>37</b>	<b>26</b>
<b>PROBABLE</b>	<b>148</b>	<b>129</b>	<b>-</b>	<b>-</b>	<b>14,189</b>	<b>11,339</b>	<b>19</b>	<b>14</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>436</b>	<b>378</b>	<b>-</b>	<b>-</b>	<b>27,638</b>	<b>22,647</b>	<b>56</b>	<b>40</b>

<u>COMPANY TOTAL</u>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT					AFTER INCOME TAXES DISCOUNTED AT				
	(% per year)					(% per year)				
RESERVES CATEGORY	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)
<b>PROVED</b>										
Developed Producing	33.0	28.7	25.5	23.1	21.2	28.6	24.7	21.9	19.7	18.0
Developed Non-producing	3.3	2.7	2.3	2.0	1.8	3.3	2.7	2.3	2.0	1.8
Undeveloped	16.4	12.6	10.0	8.2	6.9	12.3	9.4	7.4	6.1	5.1
<b>TOTAL PROVED</b>	<b>52.7</b>	<b>44.0</b>	<b>37.8</b>	<b>33.3</b>	<b>29.8</b>	<b>44.2</b>	<b>36.8</b>	<b>31.6</b>	<b>27.8</b>	<b>24.9</b>
<b>PROBABLE</b>	<b>50.1</b>	<b>31.2</b>	<b>21.3</b>	<b>15.6</b>	<b>11.9</b>	<b>34.8</b>	<b>21.4</b>	<b>14.5</b>	<b>10.4</b>	<b>7.8</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>102.8</b>	<b>75.1</b>	<b>59.2</b>	<b>48.9</b>	<b>41.7</b>	<b>79.0</b>	<b>58.2</b>	<b>46.1</b>	<b>38.2</b>	<b>32.7</b>

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

<b><u>CANADIAN PROPERTIES</u></b>	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	198	175	-	-	4,202	3,651	10	7
Developed Non-producing	90	74	-	-	143	129	-	-
Undeveloped	-	-	-	-	5,176	4,556	13	9
<b>TOTAL PROVED</b>	<b>288</b>	<b>249</b>	<b>0</b>	<b>0</b>	<b>9,521</b>	<b>8,336</b>	<b>23</b>	<b>16</b>
<b>PROBABLE</b>	<b>148</b>	<b>129</b>	<b>-</b>	<b>-</b>	<b>4,868</b>	<b>4,288</b>	<b>12</b>	<b>9</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>436</b>	<b>378</b>	<b>0</b>	<b>0</b>	<b>14,389</b>	<b>12,624</b>	<b>35</b>	<b>25</b>

<b><u>CANADIAN PROPERTIES</u></b>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
	0	5	10	15	20	0	5	10	15	20
<b>RESERVES CATEGORY</b>	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)
<b>PROVED</b>										
Developed Producing	20.7	17.5	15.3	13.7	12.4	20.7	17.5	15.3	13.7	12.4
Developed Non-producing	3.3	2.7	2.3	2.0	1.8	3.3	2.7	2.3	2.0	1.8
Undeveloped	13.4	9.9	7.5	5.9	4.7	10.4	7.7	5.9	4.6	3.7
<b>TOTAL PROVED</b>	<b>37.5</b>	<b>30.1</b>	<b>25.2</b>	<b>21.6</b>	<b>18.9</b>	<b>34.5</b>	<b>27.9</b>	<b>23.5</b>	<b>20.3</b>	<b>17.9</b>
<b>PROBABLE</b>	<b>19.9</b>	<b>13.3</b>	<b>9.5</b>	<b>7.1</b>	<b>5.4</b>	<b>14.4</b>	<b>9.5</b>	<b>6.8</b>	<b>5.0</b>	<b>3.9</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>57.3</b>	<b>43.4</b>	<b>34.6</b>	<b>28.6</b>	<b>24.4</b>	<b>48.9</b>	<b>37.5</b>	<b>30.3</b>	<b>25.3</b>	<b>21.8</b>

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

<b><u>U.S. PROPERTIES</u></b>	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	-	-	-	-	3,195	2,409	14	10
Developed Non-producing	-	-	-	-	0	0	-	-
Undeveloped	-	-	-	-	733	563	-	-
<b>TOTAL PROVED</b>	-	-	-	-	3,928	2,972	14	10
<b>PROBABLE</b>	-	-	-	-	9,321	7,051	7	5
<b>TOTAL PROVED PLUS PROBABLE</b>	-	-	-	-	13,249	10,023	21	15

<b><u>U.S. PROPERTIES</u></b>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
	0	5	10	15	20	0	5	10	15	20
<b>RESERVES CATEGORY</b>	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)
<b>PROVED</b>										
Developed Producing	12.3	11.1	10.2	9.4	8.8	7.9	7.2	6.6	6.1	5.7
Developed Non-producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undeveloped	3.0	2.7	2.5	2.3	2.1	1.9	1.7	1.6	1.4	1.3
<b>TOTAL PROVED</b>	15.2	13.8	12.7	11.7	10.9	9.8	8.9	8.1	7.5	7.0
<b>PROBABLE</b>	30.2	17.9	11.9	8.5	6.5	20.4	11.9	7.7	5.4	4.0
<b>TOTAL PROVED PLUS PROBABLE</b>	45.4	31.7	24.6	20.2	17.4	30.2	20.8	15.9	12.9	11.0

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

**Reserves Data (Forecast Prices and Costs)**

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

<b><u>COMPANY TOTAL</u></b>	<b>RESERVES</b>							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	198	176	-	-	7,491	5,601	24	17
Developed Non-producing	90	74	-	-	144	130	-	-
Undeveloped	0	0	-	-	7,128	5,125	13	9
<b>TOTAL PROVED</b>	<b>288</b>	<b>250</b>	<b>-</b>	<b>-</b>	<b>13,553</b>	<b>11,391</b>	<b>37</b>	<b>26</b>
<b>PROBABLE</b>	148	129	-	-	14,242	12,186	18	14
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>437</b>	<b>379</b>	<b>-</b>	<b>-</b>	<b>27,795</b>	<b>22,772</b>	<b>55</b>	<b>40</b>

<b><u>COMPANY TOTAL</u></b>	<b>NET PRESENT VALUES OF FUTURE NET REVENUE</b>									
	BEFORE INCOME TAXES DISCOUNTED AT (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
	0	5	10	15	20	0	5	10	15	20
<b>RESERVES CATEGORY</b>										
<b>PROVED</b>										
Developed Producing	48.4	41.5	36.6	33.0	30.1	41.2	35.3	31.1	27.9	25.4
Developed Non-producing	4.2	3.5	3.0	2.6	2.3	3.0	2.5	2.2	2.0	1.8
Undeveloped	27.7	21.1	16.8	20.2	11.6	19.7	14.8	11.6	9.5	7.9
<b>TOTAL PROVED</b>	<b>80.3</b>	<b>66.1</b>	<b>56.4</b>	<b>49.3</b>	<b>43.9</b>	<b>63.9</b>	<b>52.6</b>	<b>44.9</b>	<b>39.3</b>	<b>35.1</b>
<b>PROBABLE</b>	92.7	55.6	37.5	27.3	21.0	65.7	39.0	26.0	18.7	14.2
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>173.0</b>	<b>121.7</b>	<b>93.9</b>	<b>76.6</b>	<b>65.0</b>	<b>129.6</b>	<b>91.6</b>	<b>70.9</b>	<b>58.0</b>	<b>49.3</b>

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

<b><u>CANADIAN PROPERTIES</u></b>	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	198	176	-	-	4,272	3,706	10	7
Developed Non-producing	90	74	-	-	144	130	-	-
Undeveloped	-	-	-	-	5,185	4,562	13	9
<b>TOTAL PROVED</b>	<b>288</b>	<b>250</b>	<b>-</b>	<b>-</b>	<b>9,601</b>	<b>8,398</b>	<b>23</b>	<b>16</b>
<b>PROBABLE</b>	<b>148</b>	<b>129</b>	<b>-</b>	<b>-</b>	<b>4,915</b>	<b>4,317</b>	<b>11</b>	<b>9</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>437</b>	<b>379</b>	<b>-</b>	<b>-</b>	<b>14,516</b>	<b>12,715</b>	<b>34</b>	<b>25</b>

<b><u>CANADIAN PROPERTIES</u></b>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
	0	5	10	15	20	0	5	10	15	20
<b>RESERVES CATEGORY</b>	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)
<b>PROVED</b>										
Developed Producing	29.4	24.5	21.1	18.7	16.9	28.7	24.0	20.8	18.5	16.7
Developed Non-producing	4.2	3.5	3.0	2.6	2.3	3.0	2.5	2.2	2.0	1.8
Undeveloped	23.1	16.9	13.0	10.3	8.3	16.6	12.0	9.1	7.2	5.8
<b>TOTAL PROVED</b>	<b>56.7</b>	<b>44.8</b>	<b>37.0</b>	<b>31.5</b>	<b>27.5</b>	<b>48.3</b>	<b>38.5</b>	<b>32.1</b>	<b>27.6</b>	<b>24.3</b>
<b>PROBABLE</b>	<b>31.9</b>	<b>20.9</b>	<b>14.8</b>	<b>11.0</b>	<b>8.5</b>	<b>23.0</b>	<b>14.9</b>	<b>10.4</b>	<b>7.7</b>	<b>5.9</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>88.6</b>	<b>65.8</b>	<b>51.8</b>	<b>42.5</b>	<b>36.0</b>	<b>71.2</b>	<b>53.4</b>	<b>42.5</b>	<b>35.3</b>	<b>30.1</b>

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

<b><u>U.S. PROPERTIES</u></b>	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcft)	Net (MMcft)	Gross (Mbbbl)	Net (Mbbbl)
<b>RESERVES CATEGORY</b>								
<b>PROVED</b>								
Developed Producing	-	-	-	-	3,219	2,430	14	10
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	733	563	-	-
<b>TOTAL PROVED</b>	-	-	-	-	3,952	2,993	14	10
<b>PROBABLE</b>	-	-	-	-	9,327	7,064	7	5
<b>TOTAL PROVED PLUS PROBABLE</b>	-	-	-	-	13,279	10,057	21	15

<b><u>U.S. PROPERTIES</u></b>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT					AFTER INCOME TAXES DISCOUNTED AT				
	(% per year)					(% per year)				
<b>RESERVES CATEGORY</b>	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)
<b>PROVED</b>										
Developed Producing	19.0	17.1	15.5	14.2	13.2	12.6	11.3	10.3	9.4	8.7
Developed Non-producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undeveloped	4.6	4.2	3.9	3.6	3.3	3.1	2.8	2.5	2.3	2.1
<b>TOTAL PROVED</b>	23.6	21.3	19.4	17.8	16.5	15.6	14.1	12.8	11.7	10.8
<b>PROBABLE</b>	60.8	34.7	22.7	16.4	12.6	42.8	24.1	15.5	11.0	8.3
<b>TOTAL PROVED PLUS PROBABLE</b>	84.4	55.9	42.1	34.1	29.0	58.4	38.1	28.3	22.7	19.2

NOTE: <sup>(1)</sup> Figures may not add due to rounding.

***Additional Information Concerning Future Net Revenue (Constant Prices and Costs)***

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

<b><u>COMPANY TOTAL</u></b>						FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)	
RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	INCOME TAXES (M\$)	INCOME TAXES (M\$)	
PROVED	96,320	11,658	24,261	6,148	1,427	52,707	8,472	44,234
PROVED PLUS PROBABLE	180,528	19,990	41,409	14,468	1,725	102,783	23,767	105,332

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

<b><u>COMPANY TOTAL</u></b>		FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
RESERVES CATEGORY	PRODUCTION GROUP	
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	6,626
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	31,216
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	9,032
	Heavy Oil (Including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	50,137

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

**CANADIAN PROPERTIES**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	76,552	10,446	21,442	5,858	1,203	37,484	34,457
PROVED PLUS PROBABLE	115,189	15,396	31,909	8,900	1,487	57,344	48,865

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

**CANADIAN PROPERTIES**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	6,626
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	18,526
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	9,032
	Heavy Oil (Including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	25,581

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

**U.S. PROPERTIES**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	19,768	1,212	2,819	290	224	15,223	9,777
PROVED PLUS PROBABLE	65,339	4,594	9,500	5,568	238	45,439	56,467

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

**U.S. PROPERTIES**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	-
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	12,690
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	-
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	24,556

***Additional Information Concerning Future Net Revenue (Future Prices and Costs)***

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

<b><u>COMPANY TOTAL</u></b>						FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)	
RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	INCOME TAXES (M\$)	INCOME TAXES (M\$)	
PROVED	131,809	15,634	27,693	6,282	1,766	80,297	16,409	63,887
PROVED PLUS PROBABLE	269,260	28,718	50,261	14,777	2,280	173,045	43,440	129,604

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

<b><u>COMPANY TOTAL</u></b>		FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
RESERVES CATEGORY	PRODUCTION GROUP	
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	8,085
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	48,312
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	11,120
	Heavy Oil (Including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	82,736

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

**CANADIAN PROPERTIES**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	102,734	13,850	24,580	5,998	1,466	56,703	48,279
PROVED PLUS PROBABLE	158,505	20,861	37,774	9,120	1,939	88,632	71,242

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

**CANADIAN PROPERTIES**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	8,085
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	28,952
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	11,120
	Heavy Oil (Including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	40,670

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

**U.S. PROPERTIES**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	29,075	1,784	3,113	284	300	23,594	15,608
PROVED PLUS PROBABLE	110,755	7,857	12,487	5,657	341	84,413	58,362

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

**U.S. PROPERTIES**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	-
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	19,360
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	-
	Heavy Oil (Including solution gas and other by-products)	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	42,066

***Definitions and Other Notes***

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "Gross" means:
  - (a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
  - (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
  - (c) in relation to properties, the total area of properties in which the Corporation has an interest.
  
2. "Net" means:
  - (a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;
  - (b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
  - (c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.
  
3. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.
  
4. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
  - (a) 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, pumping equipment and wellhead assembly;
  - (b) 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 wellhead assembly;
  - (c) acquire, construct and install production facilities such as 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; and

- (d) provide improved recovery systems.
5. "Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
6. "Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain 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 and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological 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;
  - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
  - (c) dry hole contributions and bottom hole contributions;
  - (d) costs of drilling and equipping exploratory wells; and
  - (e) costs of drilling exploratory type stratigraphic test wells.
7. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
8. Definitions used for reserve categories are as follows:

*Reserve Categories*

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates.

- (d) Proved reserves are those reserves 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.

- (e) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must be met for the categorization of reserves are provided in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook").

"Economic Assumptions" will be the prices and costs used in the estimate, namely:

- (f) constant prices and costs as at the last day of the Corporation's financial year; and
- (g) forecast prices and costs.

#### *Development and Production Status*

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
  - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves 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.
  - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

#### *Levels of Certainty for Reported Reserves*

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves

are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

9. Forecast prices and costs

Future prices and costs that are:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that applies to the Corporation.

10. Constant prices and costs

Prices and costs used in an estimate that are:

- (a) the Corporation's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Corporation's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

11. ARTC is not included in the cumulative cash flow amounts because the ARTC program was cancelled by the Alberta government, effective January 1, 2007.

12. Future income tax expenses estimate (generally, year-by-year):
- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;
  - (b) without deducting estimated future costs that are not deductible in computing taxable income;
  - (c) taking into account estimated tax credits and allowances; and
  - (d) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.
13. Estimated future abandonment and reclamation costs related to a property have been taken into account by AJM in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.
14. Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.
15. The extended character of all factual data supplied to AJM were accepted by AJM as represented. No field inspection was conducted.
16. Numbers in tables may not add due to rounding.

### ***Pricing Assumptions***

The following sets for the benchmark reference prices, as at December 31, 2006, reflected in the Reserves Data. These price assumptions were provided to the Corporation by AJM, the Corporation's independent qualified evaluator.

SUMMARY OF PRICING ASSUMPTIONS  
AS OF DECEMBER 31, 2006  
CONSTANT PRICES AND COSTS

YEAR	OIL <sup>(1)</sup>		NATURAL GAS <sup>(1)</sup>		NGLs <sup>(1)</sup>		
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40 <sup>0</sup> API (\$Cdn/bbl)	AECO Gas Price (\$Cdn/Mcf)	NYMEX Gas Price (\$US/Mcf)	Edmonton Par Price Propane (\$Cdn/bbl)	Edmonton Par Price Butane (\$Cdn/bbl)	Edmonton Par Price Condensate (\$Cdn/bbl)
2006 <sup>(2)</sup>	61.05	67.06	6.14	5.50	53.65	43.59	70.41

Notes:

- (1) These summary tables identify benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) The exchange rate used to generate the benchmark reference prices in these tables is 0.88 \$US/\$Cdn.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
AS OF DECEMBER 31, 2006  
FORECAST PRICES AND COSTS

YEAR	OIL		NATURAL GAS		NGLs		
	WTI	Edmonton	AECO	NYMEX	Edmonton Par Price		
	Cushing	Par Price			Propane	Butane	Condensate
	Oklahoma	40 <sup>0</sup> API	Gas Price	Gas Price			
	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/Mcf)	(\$US/Mcf)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)
Forecast							
2007	65.00	72.85	7.40	7.80	47.35	58.30	76.50
2008	69.35	77.75	8.00	8.40	50.55	62.20	81.65
2009	70.75	79.35	7.90	8.30	51.55	63.50	83.30
2010	69.00	77.30	8.00	8.50	50.25	61.85	81.15
2011	67.10	75.15	8.25	8.65	48.85	60.10	78.90
2012	66.25	74.15	8.40	8.85	48.20	59.30	77.85
2013	67.55	75.60	8.50	9.00	49.15	60.50	79.40
2014	68.90	77.15	8.75	9.20	50.15	61.70	81.00
2015	70.30	78.70	8.90	9.35	51.15	62.95	82.65
2016	71.70	80.25	9.10	9.55	52.15	64.20	84.25
2017	73.15	81.85	9.25	9.75	53.20	65.50	85.95
2018	74.60	83.50	9.45	9.95	54.25	66.80	87.65
2019	76.10	85.15	9.65	10.15	55.35	68.10	89.40
2020	77.60	86.85	9.85	10.35	56.45	69.50	91.20
2021	79.15	88.60	10.05	10.55	57.60	70.90	83.05
2022	80.75	90.40	10.25	10.75	58.75	72.30	94.90
2023	82.35	92.20	10.45	11.00	59.95	73.75	96.80
2024	84.00	94.05	10.65	11.20	61.15	75.25	98.75
2025	85.70	95.90	10.85	11.45	62.35	76.70	100.70
2026	87.40	97.85	11.05	11.65	63.60	78.30	102.75
2026+	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

## Notes:

- (1) These summary tables identify benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) Inflation rates (for forecasting prices and costs) increasing at the rate of 2% per year.
- (3) Exchange rates (used to generate the benchmark reference prices in these tables) remaining constant at 0.88.

Weighted average prices realized by the Corporation for the year ended December 31, 2006 in Canada, were \$6.84/Mcf for natural gas, \$65.54/Bbl for crude oil and \$54.23/Bbl for natural gas liquids. In the United States, the weighted average prices were \$6.43/Mcf for natural gas and \$63.46/Bbl for oil.

## Reconciliation of Changes in Reserves and Future Net Revenue

### RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

#### COMPANY TOTAL

FACTORS	LIGHT AND MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2005	238	86	323	29	12	41	12,956	12,187	25,142	2,426	2,128	4,555
Technical revisions	(43)	(8)	(50)	7	5	9	(590)	(3,464)	(4,094)	(140)	(582)	(723)
Discoveries	83	51	134	-	-	-	39	(51)	(11)	90	43	133
Extensions, improved recovery and economic factors	-	-	-	-	-	-	705	2,749	3,454	118	458	576
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(28)	-	(28)	(9)	-	(9)	(1,720)	-	(1,720)	(324)	-	(324)
December 31, 2006	250	129	379	27	15	41	11,390	11,421	22,770	2,265	2,047	4,216

#### CANADIAN PROPERTIES

FACTORS	LIGHT AND MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2005	238	86	323	21	11	32	9,769	5,614	15,383	1,887	1,032	2,919
Technical revisions	(43)	(8)	(50)	1	-	(2)	(478)	(1,206)	(1,725)	(128)	(211)	(339)
Discoveries	83	51	134	-	-	-	39	(51)	(11)	90	43	133
Extensions, improved recovery and economic factors	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(28)	-	(28)	(5)	-	(5)	(933)	-	(933)	(189)	-	(189)
December 31, 2006	250	129	379	17	9	25	8,397	4,358	12,714	1,660	864	2,524

#### U.S. PROPERTIES

FACTORS	LIGHT AND MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved Plus Probable (MBbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2005	-	-	-	8	1	9	3,187	6,573	9,759	539	1,096	1,636
Technical revisions	-	-	-	6	5	11	(112)	(2,259)	(2,370)	(13)	(371)	(385)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions, improved recovery and economic factors	-	-	-	-	-	-	705	2,749	3,454	118	458	576
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	(4)	-	(4)	(787)	-	(787)	(135)	-	(135)
December 31, 2006	-	-	-	10	6	16	2,993	7,063	10,056	509	1,183	1,692

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE  
DISCOUNTED AT 10% PER YEAR  
NET PROVED RESERVES  
CONSTANT PRICES AND COSTS

**COMPANY TOTAL**

<u>PERIOD AND FACTOR</u>	2006 (MM\$)
Estimated Future Net Revenue at Beginning of Year	55.2
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(7.7)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(36.1)
Changes in Previously Estimated Development Costs Incurred During the Period	-
Changes in Estimated Future Development Costs	3.1
Extensions and Improved Recovery	-
Discoveries	7.7
Acquisitions of Reserves	-
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	(3.1)
Abandonment cost	0.5
Accretion of Discount	5.5
Net Change in Income Taxes	6.6
Estimated Future Net Revenue at End of Year	31.6

**CANADIAN PROPERTIES**

<u>PERIOD AND FACTOR</u>	2006 (MM\$)
Estimated Future Net Revenue at Beginning of Year	40.5
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(4.1)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(27.7)
Changes in Previously Estimated Development Costs Incurred During the Period	-
Changes in Estimated Future Development Costs	1.3
Extensions and Improved Recovery	-
Discoveries	7.7
Acquisitions of Reserves	-
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	(2.7)
Abandonment cost	0.6
Accretion of Discount	4.1
Net Change in Income Taxes	3.8
Estimated Future Net Revenue at End of Year	23.5

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE  
DISCOUNTED AT 10% PER YEAR  
PROVED RESERVES  
CONSTANT PRICES AND COSTS

**U.S. PROPERTIES**

PERIOD AND FACTOR	2006 (MM\$)
Estimated Future Net Revenue at Beginning of Year	14.7
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(3.7)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(8.4)
Changes in Previously Estimated Development Costs Incurred During the Period	-
Changes in Estimated Future Development Costs	1.8
Extensions and Improved Recovery	-
Discoveries	-
Acquisitions of Reserves	-
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	(0.3)
Abandonment cost	(0.2)
Accretion of Discount	1.5
Net Change in Income Taxes	2.8
Estimated Future Net Revenue at End of Year	8.1

**Additional Information Relating to Reserves Data*****Undeveloped Reserves****Proved Undeveloped Reserves*

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Diaz's proved undeveloped reserves include wells drilled which have not been tied-in at the effective date of the reserve report and infill drilling locations. Approximately 22% of the proved undeveloped gas reserves at December 31, 2006 were assigned to drilled wells waiting to be tied-in, which are scheduled to be connected within the next three years.

The remaining 78% of the proved undeveloped reserves are associated with planned infill drilling programs primarily in the Carmangay, Enchant and Retlaw areas in Canada and Allen Ranch in Texas. Reserves have been assigned based on geological mapping, pressure declines and production declines. To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible, proved reserves have been assigned to the undrilled spacing units.

Diaz plans to drill up to 54 (24.7 net) wells in the three Canadian areas over the next three years. This program will require capital expenditures of approximately \$5.0 million in 2008 and \$2.1 million in 2009 to develop the proved reserves and a further \$2.7 million to develop the probable undeveloped reserves. The timing of the program is also dependent upon working interest partners in the area, who may or may not agree with the plans of Diaz.

### *Probable Undeveloped Reserves*

Probable undeveloped reserves are those reserves which are to be recovered from known accumulations where a significant expenditure is required to render them capable of production, however, these reserves are less certain to be recovered. Reserves have been assigned based on geological mapping, pressure declines and production declines. To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible and that the certainties of recovering additional reserves does not meet the proved threshold, probable undeveloped reserves have been assigned.

Diaz's probable undeveloped reserves include wells drilled which have not been tied-in at the effective date of the AJM Report and for infill drilling locations. Approximately 66% of the probable undeveloped gas reserves are in the U.S. and are associated with behind pipe zones at Allen Ranch, Hound Dog, Mustang Creek and Provident City. These reserves are either waiting for operations to commence, some of which have been conducted in the first quarter of 2007, or will be tied-in when production from existing gas zones reach their economic limit and as such may not be developed for lengthy periods of time.

### *Significant Factors or Uncertainties*

Proved and probable undeveloped reserves require significant expenditures of capital to render them capable of production. There is significant risk that service or equipment may not be available at the time required and this may change the forecast of production. The cost of such estimates may also vary significantly from those assumed.

### *Future Development Costs*

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

<b>CANADA</b>	<b>FORECAST PRICES &amp; COSTS</b>		<b>CONSTANT PRICES &amp; COSTS</b>
	<b>Proved Reserves</b>	<b>Proved Plus Probable Reserves</b>	<b>Proved Reserves</b>
<b>YEAR</b>	<b>(MM\$)</b>	<b>(MM\$)</b>	<b>(MM\$)</b>
2007	0.75	1.11	0.76
2008	3.02	4.46	2.95
2009	2.17	3.44	2.09
2010	0.04	0.04	0.04
2011	-	-	-
Thereafter	0.01	0.02	0.01
<b>TOTAL</b>	<b>6.00</b>	<b>9.12</b>	<b>5.86</b>
Discounted at 10%	5.03	7.61	4.92

  

<b>U.S. (U.S. Dollars)</b>	<b>FORECAST PRICES &amp; COSTS</b>		<b>CONSTANT PRICES &amp; COSTS</b>
	<b>Proved Reserves</b>	<b>Proved Plus Probable Reserves</b>	<b>Proved Reserves</b>
<b>YEAR</b>	<b>(MM\$)</b>	<b>(MM\$)</b>	<b>(MM\$)</b>
2007	0.03	3.35	0.02
2008	-	0.23	-
2009	-	0.58	-
2010	0.02	0.01	0.00
2011	-	-	-
Thereafter	-	0.16	-
<b>TOTAL</b>	<b>0.50</b>	<b>4.98</b>	<b>0.02</b>
Discounted at 10%	0.45	4.05	0.02

Diaz plans to finance the above capital expenditures using internally generated cash flow and debt financing as required. Certain capital expenditures may be delayed from time to time as the Corporation's capital requirements are prioritized in an effort to maximize future cash flow and return on investment.

## **Other Oil and Gas Information**

### ***Principal Properties***

The following is a description of Diaz's principal oil and natural gas properties as at December 31, 2006 (unless otherwise indicated). Production stated is average working interest for the periods indicated unless otherwise stated. Gross and net acres and well information is as at December 31, 2006, unless otherwise specified. Reserve information is as evaluated by AJM in the AJM Report. The estimates of reserves and future net revenue for individual properties may not reflect the same competence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

### **United States Drilling Program**

Diaz's United States drilling program has been in the Wilcox deep gas trend concentrated in an area 100 miles South West of Houston, Texas. Diaz has an interest in mineral leases over 7 Wilcox structures. Four of the structures have been drilled with 100% success and the remaining 3 structures will be drilled in 2007.

Diaz has identified up to 16 additional Wilcox potential locations that can be drilled on its existing mineral leases.

***Cheney, Colorado County, Texas – Diaz Working Interest 20%.***

In January 2007, Diaz announced an agreement with Petrohawk Energy Corporation (“Petrohawk”) (NYSE: HK) pursuant to which Petrohawk will act as operator and drill a well on Diaz’s “Cheney” deep Wilcox Prospect, Colorado County, Texas. The prospect is situated 1.25 miles to the east of two of Diaz’s current producing wells in the Allen Ranch field. In addition, the location lies 1 mile to the southeast of two recent Newfield Exploration Company wells, which have been announced by Newfield as deep Wilcox gas producers.

Drilling is expected to commence on or about April 1, 2007. The well is to be drilled to a prospective depth of 18,100 feet and is targeting multiple Wilcox gas zones.

Diaz has a 20% working interest in 1,578 acres covering this prospect.

***Allen Ranch, Colorado County, Texas***

The Allen Ranch property is located approximately 100 miles southwest of Houston, Texas. Diaz has a 20% working interest in the prospect lands. Two successful wells have been drilled on the property.

The Hancock #1 well has been completed and fracture stimulated in four Wilcox sands which have now been commingled. At the end of December 2006, the well was producing 3.3 MMcfd.

<b>Allen Ranch</b>	<b>Natural Gas</b>
Reserves	
Proved developed producing	0.9 Bcf
Proved developed non-producing	- Bcf
Proved undeveloped	0.7 Bcf
Probable	3.7 Bcf
Total proved plus probable	5.3 Bcf
Q4 2006 average production	862 Mcfd

The Hancock #2 well was cased in February 2006. The well has been completed in four Wilcox gas zones. Subsequent to year end, during commingling operations a hole in the production tubing was discovered at 9,500 feet. The tubing has been pulled and has been sent out for inspection prior to proceeding with the commingling operation.

***Hound Dog, Lavaca County, Texas***

Diaz has a 28.1% working interest in the R. Dickson #1 well and a 25.3% working interest in the R. Dickson #2 well and 25.3% working interest in the balance of the 1,635 acres of land on the prospect.

The R. Dickson #1 well was producing 2.0 MMcfd at the end of December 2006. The R. Dickson #2 well has been completed in four Wilcox zones and commingling operations are expected to be completed in the second quarter of 2007. The R. Dickson #2 well was producing 1.9 MMcfd at the year end.

<b>Hound Dog</b>	<b>Natural Gas</b>
Reserves	
Proved developed producing	1.1 Bcf
Probable	3.8 Bcf
Total proved plus probable	4.9 Bcf
Q4 2006 average production	774 Mcfd

***Provident City, Lavaca County, Texas***

The Company owns a 13% working interest in two natural gas wells producing from zones in the Wilcox formation in the Provident City field, Lavaca County.

The Provident City #1 well has produced a total of 17.7 Bcf of natural gas to date and at December 31, 2006, was producing at a rate of 5.4 MMcfd (0.7 MMcfd net to Diaz). To increase production from the Provident City #1 well, plans are underway to install compression on the well which is expected to be in place during the second quarter 2007.

At year end, the Provident City #2 well was producing at a rate of 2.1 MMcfd (0.3 MMcfd net to Diaz) and has produced over 19.7 Bcf of gas to date.

<b>Provident City</b>	<b>Natural Gas</b>
Reserves	
Proved developed producing	1.1 Bcf
Probable	1.4 Bcf
Total proved plus probable	2.5 Bcf
Q4 2006 average production	1,039 Mcfd

**Canadian Program**

***Hays, Alberta, Canada – Diaz Working Interest 80%***

On November 30, 2006, Diaz announced it had discovered a new Arcs oil pool located near Hays. The discovery well has been tested in two zones. At the November 29, 2006, Alberta land sale, Diaz was successful in acquiring additional adjacent lands. Diaz and its partner control the entire 450-acre prospect. Based on seismic interpretation, Diaz has identified additional potential locations on its acreage.

Completion operations, construction of a battery and a solution gas sales line will be completed once government approvals have been received, which is anticipated to occur in the second quarter of 2007. Additional development drilling will commence during the second quarter of 2007.

***Enchant South – Hays, Alberta***

In the Enchant South – Hays area, located 110 miles southeast of Calgary, Diaz has an interest in 38 producing gas wells (21.7 net wells) and 3 producing oil wells (2.1 net wells).

During 2006, Diaz drilled 2 infill gas wells on the Second White Specks trend.

Production for the year averaged 0.74 MMcfd, with an exit rate of 0.77 MMcfd compared with the average production of 1.3 MMcfd for the prior year. Diaz plans to drill an additional 13 to 23 wells over the next 3 years.

<b>Enchant</b>	<b>Natural Gas</b>
Reserves	
Proved developed producing	0.7 Bcf
Proved undeveloped	1.1 Bcf
Probable	1.6 Bcf
Total proved plus probable	3.4 Bcf
Q4 2006 average production	739 Mcfd
Land - net undeveloped acreage	1,822 Acres

### ***Retlaw, Alberta***

Diaz has interests in 39 producing gas wells (14.8 net wells), 1 shut-in gas well (0.5 net wells) and 1 oil well (0.5 net) in the Retlaw area located 90 miles southeast of Calgary, Alberta.

Similar to the Enchant property, this area is prime for drilling on reduced spacing. Diaz plans to drill up to 21 wells over the next three years.

The Company's production at Retlaw, throughout 2006, averaged 0.65 MMcfd compared to 0.8 MMcfd for 2005.

<b>Retlaw</b>	<b>Natural Gas</b>
Reserves	
Proved developed producing	0.8 Bcf
Proved undeveloped	1.7 Bcf
Probable	0.7 Bcf
Total proved plus probable	3.2 Bcf
Q4 2006 average production	651 Mcfd
Land - net undeveloped acreage	3,426 Acres

### ***Jaslan, Alberta***

In November 2006, Diaz installed a compressor station and 10 kilometres of pipeline connecting 5 gas wells (2.25 net wells) in the Jaslan area, Alberta located 75 miles northeast of Edmonton. The initial production added 1.0 MMcfd net to Diaz. Diaz anticipates this production rate to decline in the first quarter of 2007 to 0.5 MMcfd net to Diaz and remain stable thereafter.

Subsequent to year end, Diaz drilled and connected a new gas well (0.375 net) which is producing 0.5 MMcfd, 0.20 MMcfd net to Diaz.

<b>Jaslan Area</b>		<b>Natural Gas</b>
Reserves		
Proved developed producing		1.0 Bcf
Probable		0.2 Bcf
Total proved plus probable		1.2 Bcf
Q4 2006 average production		548 Mcfd
Land - net undeveloped acreage		960 Acres

### *Other Alberta*

Diaz has plans in West Central Alberta to recomplate one well and drill one well. Both wells are targeting oil and gas zones.

### **Southeast Saskatchewan**

#### *Parkman Area*

Diaz presently holds an interest in 6 oil wells (4.12 net) in the Parkman area, producing from the Tilston carbonates of Mississippian age.

Diaz has plans to drill a horizontal oil well (0.5 net) during the second quarter of 2007.

<b>Parkman Area</b>		<b>Oil and NGLs</b>
Reserves		
Proved developed producing		43.2 MBbl
Proved developed non-producing		10.5 MBbl
Probable		15.0 MBbl
Total proved plus probable		68.7 MBbl
Q4 2006 average production		25 Bopd
Land - net undeveloped acreage		998 Acres

### *Oil and Gas Wells*

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2006.

LOCATION	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	21	4.6	-	-	159	70.0	6	2.9
Saskatchewan	6	3.9	-	-	-	-	-	-
Texas	-	-	-	-	8	1	-	-
Total	27	8.5	-	-	167	71.4	6	2.9

***Properties with no Attributable Reserves***

The following table sets out the Corporation's undeveloped land holdings as at December 31, 2006:

LOCATION	UNDEVELOPED ACRES	
	Gross	Net
Alberta	112,554	50,512
Saskatchewan	3,762	2,039
Texas	5,270	1,288
Other U.S. Properties	4,324	542
Total	125,910	54,381

The Corporation expects that rights to explore, develop and exploit approximately 12,300 net acres of its undeveloped land holdings in Canada will expire by December 31, 2007 unless drilling activity is conducted on the lands or applications for extension are accepted by the government or lessors before their expiry. 206 net acres of land holdings in the United States are expected to expire during 2007.

***Marketing and Forward Contracts***

Diaz's net share of oil and gas production is sold to marketing companies and other third party purchasers at the oil terminal or sales gas pipeline, with the exception of small amounts of product which are marketed by the well operators.

Where appropriate, in the opinion of management, the Corporation will sell products forward or use other derivative transactions to fix the price of its product or the exchange rate. During the year ended December 31, 2006, natural gas forward sales agreements increased the revenue Diaz would have otherwise received for its natural gas production by \$320,096, or \$1.12 per Mcf and in 2005 decreased revenue by \$183,815, or \$0.25 per Mcf.

The following fixed price contracts obligate the Corporation to deliver natural gas at the prices indicated for the contract periods. These contracts were in effect at December 31, 2006.

<u>VOLUME OF GAS</u>		<u>Contract Price</u>		<u>CONTRACT PERIOD</u>
<u>Mcf</u>	<u>GJ</u>	<u>(\$/GJ)</u>	<u>(\$/Mcf)</u>	
711	750	\$7.40	\$7.81	Apr 1, 2007 - Oct 31, 2007
711	750	\$7.62	\$8.04	Apr 1, 2007 - Oct 31, 2007
711	750	\$8.52	\$8.99	Nov 1, 2007 - Mar 31, 2008

<u>VOLUME OF GAS</u>		<u>Costless Collar</u>				<u>CONTRACT PERIOD</u>
<u>Mcf</u>	<u>GJ</u>	<u>Floor Price</u>		<u>Ceiling Price</u>		
		<u>(\$/GJ)</u>	<u>(\$/Mcf)</u>	<u>(\$/GJ)</u>	<u>(\$/Mcf)</u>	
1,896	2,000	\$7.50	\$7.91	\$10.05	\$10.60	Jan 1, 2007 - Mar 31, 2007
711	750	\$8.00	\$8.44	\$9.80	\$10.34	Nov 1, 2007 - Mar 31, 2008

### ***Additional Information Concerning Abandonment and Reclamation Costs***

The Corporation estimates the cost to abandon wells and the cost to reclaim the leases and facility sites based on costs incurred in the areas for similar wells. Salvage costs of equipment which will be removed from the site are also based on estimates currently available for such equipment. Such costs are escalated to the expected date of abandonment at an inflation rate estimate of 2%.

At December 31, 2006, Diaz had an interest in 244 wells (100 net wells), which it would be responsible for the costs to abandon in the future. The Corporation's share of the estimated abandonment cost is \$4.8 million and the present value of this amount, discounted at 10%, is \$2.4 million. In addition, the Corporation estimated it would receive \$1.5 million in total salvage revenues for these properties. The AJM Report considers only the cost of abandoning wells with respect to the future net reserves estimated. The abandonment costs were estimated to be \$1.0 million in total, having a present value of \$485,000 at a 10% discounted rate.

Diaz estimates the \$1.5 million of abandonment costs will be incurred over the next three years, having a present value of \$1.4 million at a 10% discounted rate.

### ***Tax Horizon***

Based on the forecasted production, revenue and capital expenditures used in the AJM Report for total proved reserves, Diaz will commence paying tax on its Canadian income in 2012. Diaz will continue to be taxable on its U.S. income in 2007 based on the proved reserves estimate of cash flow and capital expenditures.

**Capital Expenditures**

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2006:

<i>(\$000)</i>	CANADA	U.S.	TOTAL
Property Acquisition Costs			
Proved properties	\$ -	\$ -	\$ -
Undeveloped properties	1,157	920	2,077
Exploration Costs	2,398	177	2,575
Development Costs	2,026	2,737	4,763
Equipment and Other Assets	3,306	1,306	4,611
<b>TOTAL</b>	<b>\$ 8,886</b>	<b>\$ 5,140</b>	<b>\$ 14,026</b>

**Exploration and Development Activities**

The following table sets forth the number of wells drilled or re-entered during the year ended December 31, 2006.

	CANADA		U.S.	
	Gross	Net	Gross	Net
<b>Exploration Wells</b>				
Light and Medium Oil	3	1.8	-	-
Natural Gas	2	0.6	1	0.2
Dry	1	0.8	-	-
<b>TOTAL - Exploration</b>	<b>6</b>	<b>3.2</b>	<b>1</b>	<b>0.2</b>
<b>Development Wells</b>				
Light and Medium Oil	2	0.4	-	-
Natural Gas	3	1.4	-	-
Dry	-	-	-	-
<b>TOTAL - Development</b>	<b>5</b>	<b>1.8</b>	<b>-</b>	<b>-</b>
<b>TOTAL WELLS</b>	<b>11</b>	<b>5.0</b>	<b>1</b>	<b>0.2</b>

Wells classified as gas wells or oil wells are wells that Diaz believes are capable of production in economic quantities. See "Principal Properties" for a description of the Corporation's exploration and development plans.

**Production Estimates**

The following table sets out the volume of the Corporation's production, before royalties, estimated for the year ended December 31, 2007 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

<b>Forecast Cost and Prices</b>	Light and Medium Oil (Bopd)	Heavy Oil (Bopd)	Natural Gas (Mcf)	Natural Gas Liquids (Bopd)	BOE (BOEd)
<b>Canada</b>					
Proved developed producing	103	-	2,975	9	608
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	39	-	900	-	189
<b>Total Proved</b>	<b>142</b>	<b>-</b>	<b>3,875</b>	<b>10</b>	<b>797</b>
Probable	10	-	202	1	44
<b>Proved plus probable</b>	<b>152</b>	<b>-</b>	<b>4,076</b>	<b>10</b>	<b>842</b>
<b>U.S.</b>					
Proved producing	-	-	2,720	10	464
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	-	-	572	-	95
<b>Total Proved</b>	<b>-</b>	<b>-</b>	<b>3,292</b>	<b>10</b>	<b>559</b>
Probable	-	-	526	1	88
<b>Proved plus probable</b>	<b>-</b>	<b>-</b>	<b>3,818</b>	<b>11</b>	<b>647</b>
<b>Constant Cost and Prices</b>					
<b>Canada</b>					
Proved producing	103	-	2,965	9	606
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	39	-	901	0	189
<b>Total Proved</b>	<b>142</b>	<b>-</b>	<b>3,865</b>	<b>10</b>	<b>796</b>
Probable	10	-	203	1	45
<b>Proved plus probable</b>	<b>152</b>	<b>-</b>	<b>4,068</b>	<b>10</b>	<b>840</b>
<b>U.S.</b>					
Proved producing	-	-	2,720	10	464
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	-	-	572	-	95
<b>Total Proved</b>	<b>-</b>	<b>-</b>	<b>3,292</b>	<b>10</b>	<b>559</b>
Probable	-	-	526	1	88
<b>Proved plus probable</b>	<b>-</b>	<b>-</b>	<b>3,818</b>	<b>11</b>	<b>647</b>

**Production History**

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	CANADA				U.S. ( US\$)			
	QUARTER ENDED				QUARTER ENDED			
	2006				2006			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
<b>AVERAGE DAILY PRODUCTION<sup>(1)</sup></b>								
Light and Medium Crude Oil (Bopd)	101	133	117	164	-	-	-	-
Heavy Oil (Bopd)	-	-	-	-	-	-	-	-
Gas (Mcf)	2,861	2,282	3,069	2,913	2,729	3,017	3,274	3,029
NGLs (Bopd)	21	28	27	29	16	14	15	12
Combined (BOEd)	599	542	656	679	471	517	561	517
<b>AVERAGE PRICE RECEIVED</b>								
Light and Medium Crude Oil (\$/Bbl)	48.88	56.36	58.03	57.35	-	-	-	-
Heavy Oil (\$/Bbl)	-	-	-	-	-	-	-	-
Gas (\$/Mcf)	6.87	5.52	6.16	9.18	6.00	5.99	6.38	7.32
NGLs (\$/Bbl)	44.04	63.05	56.79	51.36	56.26	65.72	69.97	61.88
Combined (\$/BOE)	42.61	40.39	41.53	55.47	36.66	36.80	39.12	44.32
<b>ROYALTIES PAID</b>								
Light and Medium Crude Oil (\$/Bbl)	9.38	12.01	12.93	10.00	-	-	-	-
Heavy Oil (\$/Bbl)	-	-	-	-	-	-	-	-
Gas and NGLs(\$/Mcf)	0.76	0.84	0.80	1.27	2.46	2.01	0.98	2.27
Combined (\$/BOE)	5.22	6.73	6.03	7.88	14.27	11.73	5.72	13.31
<b>OPERATING EXPENSES</b>								
Light and Medium Crude Oil (\$/Bbl)	16.66	13.47	14.33	15.40	-	-	-	-
Heavy Oil (\$/Bbl)	-	-	-	-	-	-	-	-
Gas and NGLs(\$/Mcf)	0.98	0.84	0.97	0.55	1.19	0.43	0.23	0.20
Combined (\$/BOE)	10.85	14.98	12.65	11.33	6.90	2.49	1.37	1.18
<b>NETBACK RECEIVED<sup>(2)</sup></b>								
Light and Medium Crude Oil (\$/Bbl)	22.84	30.87	30.76	31.95	-	-	-	-
Heavy Oil (\$/Bbl)	-	-	-	-	-	-	-	-
Gas and NGLs(\$/Mcf)	5.13	3.78	4.39	7.36	2.34	3.56	5.17	4.85
Combined (\$/BOE)	26.54	18.68	22.85	36.26	15.48	22.58	32.03	29.83

**Notes:**

- (1) Before deduction of royalties.  
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

## **RISK FACTORS**

An investment in the shares of the Corporation is speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

### **Exploration, Development and Production Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses

resulting from the occurrence of any of these risks could have a material adverse effect on the Corporation.

### **Prices, Markets and Marketing**

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Corporation's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

The exchange rate between the Canadian and U.S. dollar also affects the profitability of the Corporation and the Canadian dollar has strengthened recently against the U.S. dollar.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation in part determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

### **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of

properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used both constant and forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

### **Substantial Capital Requirements**

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

### **Additional Funding Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms acceptable to the Corporation.

### **Issuance of Debt**

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

### **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

### **Operational Dependence**

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

### **Project Risks**

The Corporation will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;

- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

### **Competition**

The petroleum industry is competitive in all its phases. The Corporation will compete with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

### **Regulatory**

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. At this time the Alberta Government is in the process of examining the royalty and tax regime applicable to oil, gas and oil sands – see "Industry Conditions – Provincial Royalties and Incentives". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's intended business, financial condition and results of operations. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

### **Kyoto Protocol**

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject the Corporation to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has proposed a Bill, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those included in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by the Corporation's expected

operations and facilities. The direct or indirect costs of these regulations may adversely affect the expected business of the Corporation. See "Industry Conditions – Environmental Regulation".

### **Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

### **Hedging**

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

### **Availability of Drilling Equipment and Access**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

**Title to Assets**

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue received by the Corporation.

**Insurance**

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation.

**Geo-Political Risks**

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Corporation. The Corporation will not have insurance to protect against the risk from terrorism.

**Dilution**

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

**Management of Growth**

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

**Expiration of Licences and Leases**

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement

of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's results of operations and business.

### **Dividends**

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors of the Corporation considers relevant.

### **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

### **Seasonality**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

### **Third Party Credit Risk**

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

### **Conflicts of Interest**

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) (the "ABCA") which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

## **Reliance on Key Personnel**

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

## **INDUSTRY CONDITIONS**

### **Introduction**

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

### **Pricing and Marketing - Oil and Natural Gas**

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup>/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

## **Pipeline Capacity**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

## **The North American Free Trade Agreement**

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

## **Provincial Royalties and Incentives**

### **General**

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and

gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the 2006 Federal Budget, the federal corporate income tax rate will decrease to 19% in three steps: 20.5% on January 1, 2008, 20% on January 1, 2009 and 19% on January 1, 2010.

## **Alberta**

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications is May 31, 2007.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to ensure that Albertans are receiving a fair share from energy development

through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to produce a final report that will be presented to the Minister of Finance by August, 31, 2007.

### **British Columbia**

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m<sup>3</sup> produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty than the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to \$30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.
- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. With regards to the oil and gas industry the objective is to achieve clean

energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishing of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves.

## Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.
- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in

its carry forward to five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

### **Land Tenure**

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

### **Environmental Regulation**

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. No additional expenses are foreseen that are associated with complying with the new regulations. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by

the House of Commons on February 14, 2007. As details of the implementation of this legislation have not yet been announced, the effect on the Corporations' operations cannot be determined at this time.

## **Trends**

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. The Corporation will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the "October 31, 2006 Proposals") relating to income trusts and other "specified investment flow-through" entities ("SIFTs"). Pursuant to the existing provisions of the *Income Tax Act* (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the October 31, 2006 Proposals, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the October 31, 2006 Proposals will not affect the method in which the Corporation will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for small to mid-sized oil and gas companies. This may be a benefit for the Corporation as it will compete

with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Corporation's ability to sell producing properties or pursue an exit strategy.

Generally during the past year, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. The Corporation will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. The Corporation may have to rely on internally generated funds to conduct their exploration and developmental programs.

### **CONFLICTS OF INTEREST**

Certain directors and officers of the Corporation may have interest in other oil and gas companies and oil and gas properties which may from time to time conflict with the interests of the Corporation. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta).

### **HUMAN RESOURCES**

At December 31, 2006, Diaz employed 15 staff, all of which were based at its office in Calgary.

### **DIVIDEND POLICY**

The Corporation has not paid any dividends on its outstanding shares. The future payment of dividends will be dependent upon the financial requirements of the Corporation to fund future growth, the financial condition of the Corporation and other factors the board of directors of the Corporation may consider appropriate in the circumstances. Pursuant to Diaz's current credit facility it is restricted from paying dividends or redeeming or repurchasing any of its outstanding shares without the written consent of its lender.

### **DESCRIPTION OF CAPITAL STRUCTURE**

#### **Authorized Share Capital**

Diaz is authorized to issue an unlimited number of Common Shares. The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

The holders of Common Shares are entitled to receive notice of, to attend and to vote at any meeting of shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such) and to one vote per share on a ballot.

The holders of Common Shares shall be entitled to receive dividends as and when declared by the Board of Directors of the Corporation on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

The holders of Common Shares shall be entitled in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior

satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital, in such assets of the Corporation as are available for distribution.

### MARKET FOR SECURITIES

The Common Shares of the Corporation are listed for trading on the Toronto Stock Exchange (the "TSX") under the symbol "DZR". The following table sets forth the price range and trading volume of such shares on the TSX (as reported by the TSX) for the periods indicated.

MONTH	SHARE TRADING - 2006		
	Common Shares		
	High	Low	Volume
January	1.23	1.11	4,091,374
February	1.19	1.08	2,494,538
March	1.27	1.08	3,979,388
April	1.27	1.14	2,436,927
May	1.20	0.96	1,225,293
June	1.05	0.86	953,241
July	1.05	0.89	614,674
August	1.07	0.94	1,009,090
September	0.98	0.88	1,932,984
October	0.89	0.79	436,153
November	0.91	0.76	851,090
December	0.93	0.77	481,864

### DIRECTORS AND OFFICERS

#### Directors

The names, municipalities of residence, positions with Diaz, principal occupations and the period served as a director, of the directors of Diaz are set out below.

Name and Municipality	Offices Held and Time as Director	Principal Occupation
Robert W. Lamond Calgary, Alberta Canada	Chairman of the Board, President and Chief Executive Officer; director since March 11, 1994	Chairman of the Board and President of the Corporation and of Humboldt Capital Corporation ("Humboldt")
Raj K. Agrawal <sup>(1)(5)</sup> Calgary, Alberta Canada	Director since June 1, 1999	President, NRG Engineering Ltd. (petroleum engineering consulting company)
Donald K. Clark Calgary, Alberta Canada	Vice-President, Operations and Chief Operating Officer; director since January 28, 1998	Vice-President, Operations and Chief Operating Officer of the Corporation and Vice President, Operations of Humboldt
John G.F. McLeod <sup>(1)(2)</sup> Calgary, Alberta Canada	Director since June 9, 2005	President of California Oil & Gas Corp. (public oil and gas company)
Robert L. McPherson <sup>(1)(3)</sup> Calgary, Alberta Canada	Director since June 9, 2005	President of Paris Energy Ltd. (private oil and gas company)
Clive M. Stockdale <sup>(2)(7)</sup> Vancouver, B.C. Canada	Director since April 11, 1996	Vice-President, Canaccord Capital Corporation (investment dealer)
Charles A. Teare Calgary, Alberta Canada	Executive Vice-President; director since March 11, 1994	Executive Vice-President of the Corporation and of Humboldt
Allan R. Twa <sup>(2)(3)(6)</sup> Calgary, Alberta Canada	Director since January 28, 1998	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)

## Notes:

- (1) Member of Audit Committee, which committee is required pursuant to the *Business Corporations Act* (Alberta).
- (2) Member of the Compensation Committee.
- (3) Member of the Corporate Governance Committee.
- (4) The Corporation does not have an executive committee of its Board of Directors.
- (5) Raj Agrawal entered into a Settlement Agreement with the Alberta Securities Commission (the "ASC") on July 18, 2003 (approved by the ASC on August 13, 2003) in connection with an insider trading matter pursuant to which Mr. Agrawal was cease traded in securities of issuers for which he is engaged to provide professional advice or services for a period of two years from the date of the Settlement Agreement, paid an administrative penalty in the amount of \$30,000 and paid a portion of the costs of the investigation.
- (6) Allan R. Twa was a director of Gauntlet Energy Corporation which secured creditor protection pursuant to the *Companies' Creditors Arrangement Act* on June 17, 2003 and was subsequently acquired by Ketch Resources Ltd. in December 2003.
- (7) Clive M. Stockdale was a director of Enterprise Development Corporation, which was subject to a cease trade order for several months in 1998 due to certain officers of the company breaching the policy of the stock exchange on transferring options. Two officers of the company, other than Mr. Stockdale, were disciplined in the matter.

All of the directors have been engaged for more than five years in their present principal occupations or executive positions with the same or associated companies, with the exception of Mr. McPherson, who was President and CEO of KVR Resources Ltd. from January 2004 to February 2006 and Nycan Energy Corp., from April 1994 to April 2003, both oil and gas companies; and Mr. McLeod, who was President of Onco Petroleum Inc., a private oil and gas company from 2005 to March 2006 and Rally Energy Corporation, an oil and gas exploration and development company from 2001 to 2005.

The term of office of each director expires at the next annual meeting of shareholders.

## Officers

The names, municipalities of residence, positions with Diaz and the principal occupations of the senior officers of Diaz are set out below.

Name and Municipality of Residence	Office Held	Principal Occupation
Robert W. Lamond Calgary, Alberta	President, Chief Executive Officer and Chairman of the Board	Chairman of the Board and President of the Corporation and of Humboldt Capital Corporation ("Humboldt")
Brad R. Perry Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of Diaz
Charles A. Teare Calgary, Alberta	Executive Vice-President and a Director	Executive Vice-President of the Corporation and of Humboldt
Donald K. Clark Calgary, Alberta	Vice-President, Operations and Chief Operating Officer and a Director	Vice-President, Operations and Chief Operating Officer of the Corporation and Vice President, Operations of Humboldt
C. Steven Cohen Calgary, Alberta	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (barristers & solicitors)
Ray D. Arsenault Calgary, Alberta	Controller of Diaz	Controller of Diaz

As at December 31, 2006, the directors and senior officers of the Corporation as a group beneficially owned, directly or indirectly or exercised control or direction over 25,936,700 Common Shares, representing approximately 40.6% of the outstanding Common Shares of the Corporation.

## AUDIT COMMITTEE INFORMATION

### Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of director's is attached hereto as Schedule "C".

### Composition of the Audit Committee

The members of the Audit Committee are Messrs Agrawal, McPherson and McLeod. The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

– Raj Agrawal received a B.Sc. (Honors) in Petroleum Engineering from the Indian School of Mines in 1964 and a M.Sc. in Petroleum Engineering from the University of Alberta in 1968. Mr. Agrawal is President of NRG Engineering Ltd, which specializes in evaluation of reserves and value for oil and gas properties and companies. Mr. Agrawal co-founded NRG in 1978. Since then, he has served and continues to serve on the Board of Directors of several oil and gas companies, both public and private. Prior to NRG, Mr. Agrawal was Manager of Engineering for Inercomp Resources Development & Engineering where he worked from 1970. Prior to Inercomp, Mr. Agrawal was an Exploitation Engineer and Reservoir Engineer for Shell Canada. Mr. Agrawal is a member of a number of professional associations, including the Society of Petroleum Evaluation Engineers, the Petroleum Society of CIM, AIME (Society of Petroleum Engineers) and the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

– Robert McPherson received a B.Comm. (with distinction) with a focus in finance, from the University of Calgary in 1974. Mr. McPherson is President of Paris Energy Ltd., a private oil and gas company, and was previously President and CEO of KVR Resources, a private oil and gas company, from January 2004 until its sale in February 2006 and President and CEO of Nycan Energy Corp, a TSX listed company from April 1994 until its sale in April 2003.

– John McLeod, a professional engineer, holds a B.Sc. in Mechanical Engineering from the University of New Brunswick, is a member of APEGGA and has over 30 years of technical and management experience in the upstream oil and gas industry, both domestic and international. Currently, Mr. McLeod is the President and CEO of Onco Petroleum Inc., a private oil and gas exploration company with activities in Ontario and Michigan. Previously, Mr. McLeod was the President and CEO of Rally Energy Corp. from 2001 to 2005, a public oil and gas company and President and CEO of Canoro Resources Inc. from 2000 to 2001, a public oil and gas company, both companies of which were listed on the TSX Venture Exchange. In addition, Mr. McLeod was President and CEO of Arakis Energy Corporation from 1995 to 1997, a public oil and gas company listed on the TSX and Nasdaq, and President and CEO of International Sovereign Energy Corp. from 1993 to 1998.

### **Pre-Approval of Policies and Procedures**

The Audit Committee has pre-approved non-audit services for due diligence, U.S. tax compliance, Canadian tax compliance and tax planning up to \$40,000 per service.

### **External Auditor Services Fees**

#### ***Total Fees***

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were \$155,975 in 2006 and \$114,675 in 2005.

#### ***Audit-Related Fees***

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were \$76,600 in 2006 and \$57,500 in 2005. These fees related to the review of the Corporation's quarterly and year end financial statements.

#### ***Tax Fees***

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were \$79,375 in 2006 and \$57,175 in 2005. These fees related to the preparation of the Corporation's tax returns and tax compliance.

#### ***All Other Fees***

There were no other fees billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above.

## **LEGAL PROCEEDINGS**

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation or its subsidiaries is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Corporation to be contemplated.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares of the Corporation, or any known associate or affiliate of such persons in any transactions within the three most recently completed financial years of the Corporation or during the current financial year which has materially affected, or would materially affect, the Corporation or its subsidiary other than the following.

1. Humboldt owned 35.34% of the outstanding shares of Diaz at December 31, 2006.
2. During each of the last three years, Humboldt paid Diaz \$10,000 per month as its share of certain common overhead costs. The rate was increased to \$24,000 per month in November 2006 and will be reviewed annually.
3. On December 16, 2004, Humboldt subscribed for the purchase of 83,834 Class A Shares of Diaz at a price of \$0.75 per share on a flow-through share basis. The transaction represented 6.3% of a Diaz offering of 1.3 million shares.

## **TRANSFER AGENT AND REGISTRAR**

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

## **MATERIAL CONTRACTS**

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year.

## **INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than AJM, the Corporation's independent engineering evaluator and PricewaterhouseCoopers LLP, the Corporation's auditors. None of the principals of AJM had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

PricewaterhouseCoopers LLP has prepared the auditor's report on the consolidated financial statements of the Corporation for the year ended December 31, 2006. PricewaterhouseCoopers LLP has

advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

#### **ADDITIONAL INFORMATION**

Additional information relating to the Corporation may be found on SEDAR at [www.sedar.com](http://www.sedar.com). Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's Information Circular for its Annual and Special Meeting of Shareholders to be held on May 16, 2007. Additional financial information is contained in the Corporation's consolidated financial statements for the year ended December 31, 2006 and the related management's discussion and analysis for its most recently completed financial year.

Additional copies of this Annual Information Form, together with any documents, or the pertinent pages of any document, incorporated by reference herein, and any interim financial statements which have been issued by the Corporation, are available upon request by contacting the Corporation at its offices at 1800, 633 - 6th Avenue S.W., Calgary, Alberta, T2P 2Y5, or by phone at (403) 269-9889, or fax at (403) 269-9890.

**SCHEDULE "A"**  
**FORM 51-101F3**  
**REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

Management of Diaz Resources Ltd. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and
- (a) (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
- (b) (ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities and regulatory authorities commencing with this report.

The board of directors of the Corporation has:

- (c) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- (d) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (e) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

- (f) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (h) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED: March 30, 2007

(Signed) "R.W. Lamond"  
President and Chief Executive Officer

(Signed) "B.R. Perry"  
Chief Financial Officer

(Signed) "A.R. Twa"  
Director

(Signed) "C. A. Teare"  
Director



**SCHEDULE "C"**  
**AUDIT COMMITTEE MANDATE**

**MANDATE**

**Role and Objective**

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Diaz Resources Ltd. ("Diaz" or the "Corporation") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Diaz and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

**Membership of Committee**

1. The Committee will be comprised of at least three (3) directors of Diaz or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110")) unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.
2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

**Mandate and Responsibilities of Committee**

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Diaz's internal control systems:
  - identifying, monitoring and mitigating business risks; and
  - ensuring compliance with legal, ethical and regulatory requirements.
3. Review the annual and interim financial statements of Diaz and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
  - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing accounting treatment of unusual or non-recurring transactions;
  - ascertaining compliance with covenants under loan agreements;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between management and the external auditors; and
  - obtain explanations of significant variances with comparative reporting periods.
4. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Diaz's disclosure of all other financial information and will periodically access the accuracy of those procedures.
5. With respect to the appointment of external auditors by the Board:
  - recommend to the Board the external auditors to be nominated;
  - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
  - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to Diaz or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.
6. Review with external auditors (and internal auditor if one is appointed by Diaz) their assessment of the internal controls of Diaz, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Diaz and its subsidiaries.
  7. Review risk management policies and procedures of Diaz (i.e. hedging, litigation and insurance).
  8. Establish a procedure for:
    - the receipt, retention and treatment of complaints received by Diaz regarding accounting, internal accounting controls or auditing matters; and
    - the confidential, anonymous submission by employees of Diaz of concerns regarding questionable accounting or auditing matters.
  9. Review and approve Diaz's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Diaz.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Diaz. All employees of Diaz are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Diaz without any further approval of the Board.

### **Meetings and Administrative Matters**

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.
2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.
3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.
4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend

meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.
8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.
9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.
10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.
11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.