



ANNUAL INFORMATION FORM

For the period ended
December 31, 2005

March 15, 2006

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CERTAIN DEFINITIONS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means the board of directors of Midnight.

Daylight means Daylight Energy Ltd.

Daylight Trust means Daylight Energy Trust.

Midnight, we, us, our or the **Company** means Midnight Oil Exploration Ltd.

MOG means Midnight Oil & Gas Ltd.

Shareholders means holders of our Common Shares.

Vintage means Vintage Petroleum Canada Inc.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

GLJ means GLJ Petroleum Consultants Ltd.

GLJ Report means the report of GLJ dated February 24, 2006 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2005.

NI 51-101 means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

Securities

Common Shares means our common shares, as presently constituted.

Warrants means our outstanding share purchase warrants to acquire Common Shares.

Other

ARTC means the Alberta Royalty Tax Credit.

Plan of Arrangement means the plan of arrangement pursuant to the *Business Corporations Act* (Alberta) involving, *inter alia*, Midnight, Daylight, Daylight Trust, Vintage and MOG completed on November 30, 2004;

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
Mstb	thousand stock tank barrels of oil
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Natural Gas

bbls/d	barrels per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m ³	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
WTI	means West Texas Intermediate
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity
psi	means pounds per square inch
ARTC	Alberta Royalty Tax Credit

CONVERSION

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	Mmbtu	0.950
Mmbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "\$" or "dollars" are to Canadian dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with generally accepted accounting principals in Canada.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements.

MIDNIGHT OIL EXPLORATION LTD.

General

We were incorporated on September 10, 2004 under the *Business Corporations Act* (Alberta). Our head office is located at Suite 2100, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4, and our registered office is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

We are an independent public corporation engaged in the exploration, development and production of natural gas and crude oil in western Canada. We focus our primary activities in two multi-zone areas: (i) the Peace River Arch; and (ii) West Central Alberta. We pursue a risk balanced portfolio of exploration and development targeting the clastic formations of the Cretaceous and Triassic periods. Selected acquisitions may be used to broaden our production base and to add to our inventory of opportunities. Our production for the period ended December 31, 2005 was 4,666 Mcf/d of natural gas, 160 bbls/d of natural gas liquids and 166 bbls/d of oil.

GENERAL DEVELOPMENT OF THE BUSINESS

History of Midnight

On November 29, 2004, we completed our initial capitalization through an initial private placement to our officers, directors and various service providers of 4,666,666 Common Shares for total proceeds of \$7 million. Under a separate private placement, 2,333,333 Warrants were issued for total proceeds of \$47,000. Each Warrant is exercisable into one Common Share at an exercise price of \$3.00. The Warrants vest over three years provided that certain specific performance criteria are met and expire on November 29, 2008. For more information regarding the terms and conditions attached to the Warrants see "*Description of Capital Structure*".

We commenced operations on November 30, 2004. Following the completion of the Plan of Arrangement, pursuant to which certain assets of MOG and Vintage were transferred to us and former holders of common shares of MOG and Series U subscription receipt holders of Daylight Trust received: (a) one trust unit of Daylight Trust and/or one exchangeable share of Daylight; and (b) 0.50 of a Common Share, for each common share of MOG or Series U subscription receipt of Daylight Trust held by such holders.

Pursuant to the Plan of Arrangement, we acquired petroleum and natural gas properties that produced approximately 700 boe/d at closing comprised of 15% of Vintage's interest in its properties in West Central Alberta (the "Pine Creek Block") and 142,000 acres of undeveloped land in the West Central Alberta, Foothills and Peace River Arch areas. In addition, we also acquired an option to farm-in on approximately 20,000 net acres of former Vintage undeveloped lands retained by Daylight Trust on standard industry terms, thereby providing us with an additional portfolio of opportunities.

In conjunction with the Plan of Arrangement, we entered into an administrative and technical services agreement with Daylight which provides for the shared services required to manage our activities and governs the allocation of general and administrative expenses between us and Daylight. Under this agreement, Daylight receives payment for certain technical and administrative services provided to us on a cost recovery basis. As a result, we do not directly employ the services of any individual.

Significant Acquisitions

On November 29, 2005, we completed the acquisition of certain assets located in the Red Earth area of Alberta, for a total acquisition cost, payable in cash of \$47.66 million. The assets acquired included 1.8 million boe of high quality, long life oil and natural gas reserves on a proven plus probable basis, 67,700 net acres of undeveloped land, 144 square kilometers of 3D seismic and production of approximately 850 boe/d after taking into consideration MRLs (Maximum Rate Limitations). From October 1, 2005 (the effective date of the acquisition) to November 29, 2005 (the closing date), 4 gross (2.8 net) successful oil wells were drilled and production increased from 650 boe/d to approximately 850 boe/d. We have also commenced an active drilling program on these lands drilling 8 wells in the fourth quarter of 2005.

The cash to close the acquisition was funded by an issuance of 12,000,000 subscription receipts at a price of \$4.00 per subscription receipt for gross proceeds of \$48 million. Each subscription receipt was converted into one Common Share in accordance with their terms on November 30, 2005.

For further information, please refer to our business acquisition report dated February 10, 2006 with respect to this acquisition which has been filed on SEDAR at www.sedar.com. The assets acquired are reflected in this Annual Information Form in the "*Statement of Reserves Data and Other Oil and Gas Information*".

Recent Developments

Our Board of Directors has approved a \$45 to \$55 million capital budget for us, subject to financing. In 2006, we expect to drill approximately 24 net wells concentrating in West Central Alberta, the Peace River Arch and Red Earth.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated February 24, 2006 and prepared as of February 1, 2006. The effective date of the Statement is December 31, 2005.

Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ in the GLJ Report dated February 24, 2006 and effective December 31, 2005. The Reserves Data summarizes our oil, liquids and natural gas reserves 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 with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta and British Columbia. We do not have any heavy oil reserves.

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 crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. For more information as to the risks involved, see "*Risk Factors*".

The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Oil and Natural Gas Disclosure in Form 51-101F3 are included in Schedules "A" and "B" to this Annual Information Form.

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS**

<i>Reserves Category</i>	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(MMcf)</i>	<i>(MMcf)</i>	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(Mboe)</i>	<i>(Mboe)</i>
Proved								
Developed Producing	855	751	7,898	6,044	198	130	2,369	1,888
Developed Non-Producing	63	57	2,069	1,521	55	36	463	347
Undeveloped	205	174	2,228	1,799	12	8	588	482
Total Proved	1,123	982	12,196	9,364	264	174	3,420	2,717
Probable	918	828	3,550	2,776	74	49	1,584	1,340
Total Proved Plus Probable	2,041	1,810	15,747	12,141	339	223	5,004	4,056

<i>(\$ thousands)</i>	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at %/year					After Income Taxes Discounted at %/year				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	86,175	71,822	62,219	55,297	50,039	84,575	70,379	60,911	54,103	48,945
Developed Non-Producing	14,975	12,094	10,230	8,925	7,960	11,656	9,115	7,537	6,476	5,720
Undeveloped	16,975	12,845	10,134	8,211	6,777	12,225	8,840	6,690	5,200	4,108
Total Proved	118,125	96,762	82,584	72,433	64,776	108,456	88,335	75,138	65,779	58,774
Probable	56,359	34,205	23,977	18,046	14,153	40,625	23,447	15,773	11,437	8,641
Total Proved Plus Probable	174,484	130,967	106,560	90,480	78,929	149,081	111,783	90,910	77,216	67,415

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS**

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
<i>(\$ thousands)</i>								
Proved Reserves	211,691	37,868	44,574	9,839	1,285	118,125	9,669	108,456
Proved Plus Probable Reserves	312,533	52,389	65,973	18,261	1,427	174,484	25,403	149,081

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
<i>(\$ thousands)</i>		
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	35,833
	Natural gas (including by-products but excluding solution gas from oil wells)	46,751
	Other revenue and costs	-
	Total	82,584
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	49,092
	Natural gas (including by-products but excluding solution gas from oil wells)	57,468
	Other revenue and costs	-
	Total	106,560

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(MMcf)</i>	<i>(MMcf)</i>	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(Mboe)</i>	<i>(Mboe)</i>
Proved								
Developed Producing	827	723	7,733	5,913	196	129	2,312	1,838
Developed Non-Producing	63	57	2,089	1,536	55	37	466	350
Undeveloped	192	161	2,218	1,790	11	8	573	467
Total Proved	1,082	941	12,040	9,239	262	174	3,351	2,654
Probable	956	867	3,509	2,741	74	49	1,615	1,373
Total Proved Plus Probable	2,038	1,807	15,549	11,981	336	223	4,966	4,027

<i>(\$ thousands)</i>	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at %/year					After Income Taxes Discounted at %/year				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	66,891	58,041	51,834	47,173	43,507	66,294	57,487	51,317	46,689	43,053
Developed Non-Producing	11,699	9,780	8,515	7,607	6,918	9,602	7,851	6,733	5,955	5,380
Undeveloped	12,288	9,463	7,564	6,190	5,148	9,816	7,168	5,422	4,183	3,259
Total Proved	90,877	77,284	67,913	60,970	55,573	85,712	72,506	63,472	56,826	51,693
Probable	40,206	24,126	16,829	12,636	9,887	34,489	19,584	12,894	9,138	6,737
Total Proved Plus Probable	131,083	101,411	84,742	73,605	65,460	120,202	92,090	76,366	65,964	58,430

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS**

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
<i>(\$ thousands)</i>								
Proved Reserves	180,850	32,587	45,955	9,912	1,519	90,877	5,165	85,712
Proved Plus Probable Reserves	275,693	44,659	79,701	18,382	1,868	131,083	10,882	120,202

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
<i>(\$ thousands)</i>		
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	29,628
	Natural gas (including by-products but excluding solution gas from oil wells)	38,285
	Other revenue and costs	-
	Total	<u>67,913</u>
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	38,703
	Natural gas (including by-products but excluding solution gas from oil wells)	46,039
	Other revenue and costs	-
	Total	<u>84,742</u>

Definitions and Other Notes to Reserves Data and Tables

In the tables following in this section and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. Columns may not add due to rounding.
2. "Gross" means:
 - (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest received by us;
 - (b) in relation to wells, the total number of wells in which we have an interest; and
 - (c) in relation to properties, the total area of properties in which we have an interest.
3. "Net" means:
 - (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interests in production or reserves;

- (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
 - (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.
4. "Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
5. "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, to the extent necessary in developing the reserves;
 - (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.
6. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.
7. "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 (sometimes referred to in part as "prospecting costs") 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 (collectively sometimes referred to as "geological and geophysical costs");
 - (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.

8. "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.
9. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

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.

- (a) 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; and
- (b) 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.

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

- (a) constant prices and costs as at the last day of our financial year; and
- (b) 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; and
 - (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% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50% 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.

10. 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 we are 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 us.

11. Constant prices and costs

Prices and costs that are:

- (a) Our 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 we are 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), Midnight's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

- 12. ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. We qualified for the maximum ARTC in 2005 on proved plus probable reserves.

- 13. Future income tax expenses

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 (for example, Crown royalties) 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 Midnight's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

- 14. Future net revenue

The estimated net amount to be received with respect to the development and production of reserves estimated using:

- (a) constant prices and costs; or
- (b) forecasted prices and costs.

This net amount is computed by deducting from estimated future revenues: estimated amounts of future royalty obligations, costs related to the development and production of reserves, well abandonment costs and future income tax expenses.

- 15. Estimated future abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, the reasonable estimated future well abandonment costs were deducted. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.
- 16. Both the constant and forecast price and cost and assumptions assume the continuance of current laws and regulations.
- 17. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

Pricing Assumptions

The following sets for the benchmark reference prices, as at January 1, 2006, reflected in the Reserves Data. These price assumptions were provided by GLJ.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF JANUARY 1, 2006 FORECAST PRICES AND COSTS

Year	OIL			NATURAL GAS AECO Gas Price (\$Cdn/ MMbtu)	EDMONTON LIQUIDS PRICES			Inflation Rates ^(a) %/Year	Exchange Rate ^(b) (\$US/ \$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)		Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)		
<i>Forecast</i>									
2006	57.00	66.25	55.75	10.60	42.50	49.00	67.00	2.0	0.850
2007	55.00	64.00	55.25	9.25	41.00	47.25	65.25	2.0	0.850
2008	51.00	59.25	51.25	8.00	38.00	43.75	60.50	2.0	0.850
2009	48.00	55.75	48.25	7.50	35.75	41.25	56.75	2.0	0.850
2010	46.50	54.00	46.75	7.20	34.50	40.00	55.00	2.0	0.850
2011	45.00	52.25	45.25	6.90	33.50	38.75	53.25	2.0	0.850
2012	45.00	52.25	45.25	6.90	33.50	38.75	53.25	2.0	0.850
2013	46.00	53.25	46.00	7.05	34.00	39.50	54.25	2.0	0.850
2014	46.75	54.25	47.00	7.20	34.75	40.25	55.25	2.0	0.850
2015	47.75	55.50	48.00	7.40	35.00	41.00	56.50	2.0	0.850
2016	48.75	56.50	48.75	7.55	36.25	41.75	57.75	2.0	0.850
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.850

Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.

The weighted average realized sales prices by us for the period ended December 31, 2005 were \$9.07/Mcf for natural gas, \$68.68/bbl for crude oil and \$55.79/bbl for NGLs.

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Report. Product prices were not escalated beyond December 31, 2005. In addition, operating and capital costs have not been increased on an inflationary basis. The prices used for the mix of crude oil gravities and various gas contracts were as follows (adjusted for quality and transportation):

SUMMARY OF PRICING ASSUMPTIONS AS OF DECEMBER 31, 2005 CONSTANT PRICES AND COSTS

Year	OIL			NATURAL GAS AECO Gas Price (\$Cdn/MMbtu)	EDMONTON LIQUID PRICES			EXCHANGE RATE (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)		Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)	
December 31, 2005	61.04	68.27	51.84	9.71	43.69	50.52	71.67	0.8577

*Reconciliations of Changes in Reserves and Future Net Revenue***RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

Factors	Light and Medium Oil			Conventional Natural Gas		
	Net Proved (Mbbls)	Net Probable (Mbbls)	Net Proved Plus Probable (Mbbls)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
At December 31, 2004	49	15	64	6,330	1,984	8,314
Extensions	198	50	248	3,256	876	4,132
Improved Recovery	-	-	-	-	-	-
Technical Revisions	12	(7)	5	314	(281)	33
Discoveries	-	-	-	-	-	-
Acquisitions	735	808	1,543	642	162	804
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(53)	-	(53)	(1,302)	-	(1,302)
December 31, 2005	<u>941</u>	<u>866</u>	<u>1,807</u>	<u>9,239</u>	<u>2,742</u>	<u>11,981</u>

**RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE
RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

Factors	Natural Gas Liquids			BOE		Net Proved Plus Probable (Mboe)
	Net Proved (Mbbls)	Net Probable (Mbbls)	Net Proved Plus Probable (Mtbl)	Net Proved (Mboe)	Net Probable (Mboe)	
At December 31, 2005	120	32	152	1,224	378	1,602
Extensions	89	26	115	830	222	1,052
Improved Recovery	-	-	-	-	-	-
Technical Revisions	3	(9)	(5)	68	(63)	5
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	842	835	1,677
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(39)	-	(39)	(309)	-	(309)
December 31, 2005	<u>174</u>	<u>49</u>	<u>223</u>	<u>2,655</u>	<u>1,372</u>	<u>4,027</u>

Note:

(1) We do not have any unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, etc.).

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

Period and Factor	2005 After Tax	2005 Before Tax
<i>(\$ thousands)</i>		
Estimated Future Net Revenue at December 31, 2004	23,049	24,907
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties ⁽¹⁾	(13,328)	(13,328)
Net Change in Prices, Production Costs and Royalties Related to Future Production ⁽²⁾	16,463	16,463
Development Costs Incurred During the Period ⁽³⁾	13,011	13,011
Changes in Estimated Future Development Costs ⁽⁴⁾	(13,011)	(13,011)
Extensions and Improved Recovery ⁽⁵⁾	25,232	25,232
Discoveries ⁽⁵⁾	-	-
Acquisitions of Reserves ⁽⁵⁾	25,597	25,597
Dispositions of Reserves ⁽⁵⁾	-	-
Net Change Resulting from Revisions in Quantity Estimates	-	-
Accretion of Discount ⁽⁶⁾	2,491	2,491
Net Change in Income Taxes ⁽⁷⁾	(5,587)	-
Changes Resulting from Technical Reserves Revisions	2,067	2,067
All Other Changes ⁽⁸⁾	(846)	(845)
Estimated Future Net Revenue at December 31, 2005	<u>75,138</u>	<u>82,584</u>

Notes:

- (1) Our actual before income taxes, excluding general and administrative expenses.
- (2) The impact of the changes in prices and other economic factors on future net revenue.
- (3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
- (4) The change in forecast development costs.
- (5) End of period net present value of the related reserves.
- (6) Estimated at 10% of the beginning of the period net present value.
- (7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of the period.
- (8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2005 versus forecast, etc.

Additional Information Relating to Reserves Data*Undeveloped Reserves*

The following discussion generally describes the basis on which we attribute our proved and probable undeveloped reserves and our plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill drill locations. The majority of these reserves are planned to be on stream within a two-year time frame.

By March 31, 2006, Midnight will have either placed on production or tied-in wells capable of production which were assigned reserves of 292 Mboe of proven developed non-producing and 391 Mboe of proven undeveloped reserves. These reserves placed on production or tied in are equivalent to 63% of the proven developed non-producing reserves and 68% of the proven undeveloped reserves assigned by GLJ at December 31, 2005. The combined proven developed non-producing and proven undeveloped reserves placed on production or tied-in wells capable of production are 683 Mboe which is 66% of the total proven developed non-producing and proven undeveloped reserves assigned.

As of December 31, 2005 the total estimated development capital associated with proven reserves is \$9,912,000. Ninety-five percent (95%) of the capital is forecast to be spent within the next two years to develop these reserves.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive infill drilling locations and land contiguous to production. The majority of these reserves are planned to be on stream within a two-year time frame.

By March 31, 2006, Midnight will have either placed on production or tied-in wells capable of production which were assigned probable additional reserves of 193 Mboe which is equivalent to 12% of the total.

As of December 31, 2005 the total estimated development capital associated with probable reserves is \$8,470,000. Ninety-eight percent (98%) of the capital is forecast to be spent within the next two years to develop these reserves.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. All of our reserves were evaluated by GLJ.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in oil and gas prices and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below:

Year (\$ thousands)	Forecast Prices and Costs		Constant Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2006	9,147	15,736	9,147	15,736
2007	279	1,961	274	1,923
2008	-	153	-	147
2009	60	60	57	57
2010	85	87	78	80
Thereafter	341	385	283	318
Total Undiscounted	9,912	18,382	9,839	18,261
Total Discounted at 10%	9,198	17,074	9,165	17,005

We estimate that our internally generated cash flow will be sufficient to fund our future development costs. We typically have three sources of funding to finance our capital expenditure programs: (i) internally generated cash flow; (ii) debt financing; and (iii) new equity issue, if available on favourable terms.

Other Oil and Gas Information

Oil and Gas Properties

We have existing production in the Pine Creek Block and an exploration focus in the southern portion of West Central Alberta and the Peace River Arch areas, where we hold the majority of our undeveloped lands. We also have farm-in arrangements with Daylight Trust in Cypress and Milo, British Columbia and to a lesser extent in our Pine Creek Block. The following is a description of these oil and natural gas properties in which we have an interest.

West Central Alberta – Producing Properties

Our primary producing region is the Pine Creek Block. We hold minor interests in 197 gross wells in this area which account for approximately 34% of our proved plus probable reserves and 30% of our production. The Pine Creek Block is a 63 square township block between Edmonton and Grand Prairie, Alberta. GLJ has assigned total proved plus probable reserves of 1,700 Mboe to our interest in this area.

The Pine Creek Block is comprised of major producing properties of Fox Creek, Windfall, Kaybob, Fir, Bigstone, Oldman, Marlboro, Pine Creek, Groat and McLeod. This area is characterized by multi-zoned gas and oil prospects from the shallower gas prone Belly River formation to the deeper but highly prospective Leduc and Wabamun gas horizons underlying the Pine Creek Gas Unit. We have access to or an ownership interest in a majority of the infrastructure that exists in this area.

In 2005, we participated in 20 wells (1.75 net) in this area. Nineteen (1.65 net) resulted in gas wells and 1.0 (0.1 net) is still standing. In 2006, we anticipate participating in 26 wells (1.6 net) in the area with a combination of exploration and development drilling targeting many prospective horizons including, but not limited to, the Belly River, Cardium, Dunvegan, Viking, Notikewan, Bluesky, Gething, Cadomin, Jurassic Nordegg, Triassic Montney, Wabamun and Leduc. Our management has extensive experience in these types of reservoirs and will be employing the use of seismic and our extensive core and cutting database in addition to detailed log analysis and geological mapping to minimize the risk in order to maximize the potential return of each investment opportunity.

West Central Alberta – Exploration Properties

We have the right to farm-in on Daylight Trust on industry standard terms on various exploratory locations within the Pine Creek Block that do not meet Daylight Trust's risk profile.

In Caroline, we have a significant land base targeting Cretaceous aged gas in the Viking and Cardium sands. We will continue to develop this opportunity rich land base through a combination of high working interest drilling and partial farm-outs to spread our risk exposure.

We also hold varying interests in exploratory lands within the highly prized Nisku oil fairway in Pembina which we intend to evaluate through a joint drilling program. Two 3D seismic programs have recently been shot over the undeveloped lands to assist in exploring for Nisku oil. We have working interests varying from 37.5% to 100% in seven sections of land in this area and are committed to participate in one well (0.375 net) on the play in 2006.

Peace River Arch – Exploration Properties

Our management and technical staff have extensive experience in exploring for and developing the gas charged Cretaceous and Triassic aged reservoirs in this area. In 2005, we participated in 10 wells (3.3 net) in this area. Two wells (0.6 net) resulted in oil wells, six (2.1 net) in gas wells and 2 (0.6 net) are still standing. Our undeveloped land base has multi-zoned potential including, but not limited to, the Dunvegan, Cadotte, Notikewan, Falher, Gething, Cadomin, Halfway and the Montney formations. GLJ has assigned total proved plus probable reserves of 689 Mboe to our interest in this area. In 2006, we anticipate participating in 13 wells (6.2 net) in this area. We will also continue to develop this opportunity rich land base through a combination of high working interest drilling and

partial farm-outs to spread our risk exposure. To date, we have also entered into a number of farm-in agreements with third parties in the area.

Foothills – Daylight Farm-ins

We have the right to farm-in on industry standard terms on various new drilling locations in the Cypress and Milo areas of British that do not meet Daylight Trust's risk profile.

Red Earth – Development and Exploration Properties

We acquired our Red Earth assets effective October 1, 2005. The assets include a mix of operated and non-operated wells ranging in interests from 25 to 100%. GLJ has assigned total proved plus probable reserves of 2,082 Mboe to our interest in this area. Along with the producing wells, we also acquired an interest in 67,700 net undeveloped acres that contain both exploratory and development well potential. The main producing horizons in the area are the Granite Wash and Keg River formations. Both zones contain sweet, light (40° API) oil. Uphole potential also exists in the Slave Point (oil) and Bluesky (gas). In 2005, we participated in 8 (3.8 net) oil wells in this area.

We anticipate participating in 27 oil wells (14.1 net) for an average working interest of 52% in this area in 2006. Seventeen will be operated and 10 will be non-operated. As of March 15, 2006, we had participated in 9 oil wells (5.0 net) and we anticipate drilling two more (2.0 net) before the end of the first quarter. The existing Keg River pools in this area are being actively water flooded. Our operated lands are in various stages of development but could be amenable to water flooding in the future.

Sheldon – Development and Exploration Properties

We acquired this partially developed sweet gas property as part of the Plan of Arrangement in 2004. The area is characterized by relatively shallow, high deliverability, gas wells. The main producing horizons are the Bluesky and Gething zones with some uphole potential in the Badheart and Dunvegan. At the time of acquisition, the property consisted of three stranded gas wells (2.5 net) with a number of undeveloped sections that were scheduled to expire in late 2005. We drilled 2 gas wells (1.5 net) and were able to continue much of the land into 2006.

We plan to drill 4 more wells (4.0 net) in early 2006 and tie-in the existing wells. GLJ has assigned 283 Mboe of proved reserves and 393 Mboe of proved plus probable reserves to this property.

Exploration and Development Strategy of Midnight

Our exploration and development strategy involves the expansion of our asset base in Western Canada through: (i) drilling on our existing properties; (ii) adding lands and opportunities through acquisitions at Crown sales; (iii) farm-ins involving the drilling of wells to earn a negotiated working interest on the third parties' properties; and (iv) the acquisition of new properties from third parties. We intend to acquire additional land and drilling opportunities that have both development and exploration drilling potential in areas in which we have expertise and that have multi-zone productive capability which are within an area with existing production facilities accessible to or owned by us.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2005:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	67	17.2	15	2.7	178	20.4	50	8.1
British Columbia	-	-	-	-	1	0.2	1	0.5
Total	67	17.2	15	2.7	179	20.6	51	8.6

Properties with no Attributable Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2005:

	Undeveloped Acres	
	Gross	Net
Alberta	318,800	160,400
British Columbia	35,400	26,000
Total	354,200	186,400

Rights to explore, develop and exploit 40,000 net acres of 186,400 of our net acres relate to title documents whose primary terms come to an end between January 1, 2006 and December 31, 2006. Of these, we estimate that over 20,000 net acres will be further continued through submission of continuation applications and that additional lands will be continued through drilling.

We have no material work commitments with respect to our undeveloped land holdings. We are committed to shoot two 3D seismic programs in Northern Alberta and to drill one farm-in well. These work commitments will amount to an estimated capital expenditure in the aggregate of \$1.1 million.

Forward Contracts

We are not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which we may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Drilling Activity

The following table summarizes our drilling results for the period ended December 31, 2005:

	Exploratory		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	2	1.5	8	2.9
Natural Gas	12	3.4	20	3.0
Dry	-	-	-	-
Total	14	4.9	28	5.9

We currently expect to drill 20 to 25 net wells in 2006, with 12 to 15 wells expected to be development wells and 8 to 10 wells expected to be exploratory wells. As of March 15, 2006, 15 (7.7 net) wells have been drilled, of which 7 (5.1 net) wells have been cased as exploratory wells and 8 (2.6 net) wells have been cased as development wells. We may revise our estimate of exploratory and development drilling as new opportunities are presented.

Abandonment and Reclamation Costs

The following table discloses our abandonment and reclamation costs anticipated as at December 31, 2005, calculated both at an undiscounted and at a 10% discount rate with a portion thereof anticipated to be paid in each of the next three years.

	Abandonment and Reclamation Costs escalated at 2% Undiscounted (\$000)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (\$000)
Total as at December 31, 2005	2,871	996
Anticipated to be paid in 2006	264	252
Anticipated to be paid in 2007	157	136
Anticipated to be paid in 2008	165	130

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of the properties held by us upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

We currently estimate that the future environmental and reclamation obligations net of salvage value in respect of our assets will aggregate approximately \$2,871,000 escalated at 2% per year. Of this amount, \$1,868,000 has been reflected in the disclosed Reserves Data for proved plus probable reserves.

We estimate the costs to abandon and reclaim all shut-in and producing wells, facilities, gas plants, pipelines, batteries and satellites. Our model for estimating the amount and timing of future abandonment and reclamation expenditures is done on an operating area level. Estimated expenditures for each operating area are based on management's prior experience in the areas. Abandonment and reclamation costs have been estimated over an approximate 40 year period with the majority of the costs estimated to be incurred in the next 20 years. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of our associated reserves. We estimate that future salvage recovery on facilities is expected to exceed future abandonment costs on those facilities. As at December 31, 2005, we expected to incur reclamation and abandonment costs in respect of 49.1 net wells.

Tax Horizon

We forecast our tax horizon assuming a continuing business model whereby we re-invest cash flow at historic capital efficiencies in order to achieve minimum production and reserve growth. Under this scenario, we will not be in a taxable position. This result is dependent upon commodity prices and capital spending levels.

At December 31, 2005, we had approximately \$102.5 million in tax pools available to shelter taxable income in future years of which approximately 15% is comprised of Canadian exploration expense which is deductible at 100%.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2005.

Expenditures	2005
<i>(\$ thousands)</i>	
Property acquisition costs – Proved Properties	\$47,666
Property acquisition costs – Undeveloped Properties ⁽¹⁾	3,564
Exploration Costs ⁽²⁾	12,175
Development Costs ⁽³⁾	13,093
Total	<u>\$76,498</u>

Notes:

- (1) Cost of land acquired, and lease rentals on unproved properties.
- (2) Geological and geophysical costs, capitalized general and administration costs and drilling and completion costs for exploration wells.
- (3) Drilling and completion costs for development wells and equipping, tie-in and facility costs for all wells.

Production Estimates

The following table sets out the 2006 yearly average rates for our production as estimated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data*".

	Light and Medium Oil	Natural Gas	Natural Gas Liquids	boe
	<i>(bbls/d)</i>	<i>(Mcf/d)</i>	<i>(bbls/d)</i>	<i>(boe/d)</i>
Proved Producing				
Red Earth	525	482	-	606
Pine Creek	-	1,308	16	235
Oldman	-	552	22	114
Wapiti	-	547	44	135
Others	61	1,835	50	415
Total Proved Producing	<u>586</u>	<u>4,724</u>	<u>132</u>	<u>1,505</u>
Total Proved				
Red Earth	657	820	-	794
Pine Creek	-	1,425	18	256
Wapiti	-	1,118	91	277
Oldman	-	576	23	119
Others	69	3,246	54	664
Total Proved	<u>726</u>	<u>7,185</u>	<u>186</u>	<u>2,110</u>

Production History

The following table summarizes our net daily production, before royalties, for the periods indicated.

	Quarters Ended 2005			
	Q4	Q3	Q2	Q1
Light and Medium Crude Oil & NGLs <i>(bbls/d)</i>	599	270	297	135
Natural Gas <i>(mcf/d)</i>	4,694	4,885	5,151	3,924
Combined <i>(boe/d)</i>	<u>1,382</u>	<u>1,084</u>	<u>1,156</u>	<u>788</u>

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

	Quarters Ended 2005			
	Q4	Q3	Q2	Q1
Light and Medium Crude Oil & NGLs (\$/bbls)				
Average Price Received	66.19	64.97	53.64	58.96
Royalties Paid	16.93	11.71	17.69	11.61
Operating Expenses	8.22	9.05	9.20	11.03
Transportation Expenses	0.05	0.20	0.00	0.25
Netback Received ⁽¹⁾	<u>40.99</u>	<u>44.01</u>	<u>26.75</u>	<u>36.07</u>
Natural Gas (\$/mcf)				
Average Price Received	11.73	9.70	7.62	6.92
Royalties Paid	2.87	3.09	1.97	1.59
Operating Expenses	1.37	1.51	1.53	1.84
Netback Received ⁽¹⁾	<u>7.49</u>	<u>5.10</u>	<u>4.12</u>	<u>3.49</u>
Combined (\$/boe)				
Average Price Received	69.02	60.13	48.01	44.68
Royalties Paid	17.09	16.82	13.33	9.89
Operating Expenses	8.22	9.05	9.20	11.03
Transportation Expenses	0.03	0.05	0.00	0.04
Netback Received ⁽¹⁾	<u>43.68</u>	<u>34.21</u>	<u>25.48</u>	<u>23.72</u>

Notes:

(1) Netbacks are calculated by subtracting royalties, operating costs and transportation from revenues.

The following table indicates our average daily production from our important fields for the year ended December 31, 2005:

	Light and Medium Crude Oil and NGLS	Gas	boe
	<i>(bbls/d)</i>	<i>(Mcf/d)</i>	<i>(boe/d)</i>
Wapiti	84	1,088	266
Pinecreek	15	1,080	195
Oldman	23	589	122
Red Earth	101	51	110
Other Fields	103	1,808	403
Total Alberta	<u>326</u>	<u>4,616</u>	<u>1,096</u>
Total British Columbia	-	50	8
Total	<u><u>326</u></u>	<u><u>4,666</u></u>	<u><u>1,104</u></u>

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value. At March 15, 2006, we had outstanding, 38,327,829 Common Shares, 1,084,300 options, each of which is exercisable for one (1) Common Share at an average exercise price of \$3.50 per share and 2,083,333 Warrants.

Our shareholders have authorized the number of Common Shares that may be subject to options granted under our stock option plan at any time to 10% of the number of outstanding Common Shares from time to time. Based on the issued and outstanding Common Shares as at March 15, 2006 the number of options which may be issued under our stock option plan is currently limited to 3,832,783 options of which options to purchase 1,084,300 (3% of the outstanding Common Shares) are outstanding and 2,748,483 options are available for future grants (7% of the outstanding Common Shares). Notwithstanding these authorization limits, we have agreed to limit option grants

under our stock option plan to 5% of our outstanding Common Shares until November 30, 2005 and to 7.5% of the outstanding Common Shares until November 30, 2006.

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital. Our share provisions have been filed on SEDAR at www.sedar.com.

Common Shares

Subject to the provisions of the *Business Corporations Act* (Alberta), holders of Common Shares are entitled to receive notice of, to attend and vote at all meetings of our shareholders and are entitled to one vote, in person or by proxy, for each Common Share held.

Holders of Common Shares are entitled to receive, if, as and when declared by our directors, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by our directors.

On our liquidation, dissolution or winding-up, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs, holders of the Common Shares shall be entitled to receive our remaining property and assets.

Warrants

The Warrants were issued under and pursuant to a private placement on November 29, 2004. Each Warrant is exercisable for one (1) Common Share at a price of \$3.00 per share provided that certain specific performance criteria are met. One-third of the Warrants vested on November 29, 2005 and were exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$3.00 per share. An additional one-third of the Warrants will vest on November 29, 2006 and will only be exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$3.75 per share. The balance of the Warrants will vest on November 29, 2007 and will only be exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$4.50 per share. All of these performance requirements were met in December 2005. The Warrants expire on November 29, 2008.

MARKET FOR SECURITIES

Our Common Shares are listed for trading on the Toronto Stock Exchange under the symbol "MOX". The following table sets out the price range for and trading volume of the Common Shares since commencement of trading on December 2, 2004.

	<u>High</u>	<u>Low</u>	<u>Volume</u>
2004			
December	\$4.20	\$3.20	6,559,221
2005			
First quarter	\$4.98	\$3.06	7,362,504
Second quarter	\$4.05	\$3.10	7,467,768
Third quarter	\$4.59	\$3.20	6,871,415
Fourth quarter	\$4.85	\$3.80	3,725,282
2006			
January	\$4.70	\$4.01	835,805
February	\$4.30	\$3.70	2,189,853
March (1-15)	\$4.00	\$3.70	1,134,764

DIVIDEND POLICY

We have not paid or declared any dividends on our outstanding Common Shares and have no intention of paying dividends in the foreseeable future. The payment of dividends depends upon our requirements to fund future growth, our financial condition and other factors that the board of directors may consider appropriate in the circumstances.

OFFICERS AND DIRECTORS

The names, municipalities of residence of our directors and officers, their positions and offices held with us, the date they became a director and their principal occupations during the past five years are as follows:

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Paul E. Moynihan ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Chairman and Director	2004	Mr. Moynihan has been a Managing Director & Partner of Mustang Capital Partners Inc., a Calgary based investment banking and funds management firm, since December 2002. Prior thereto, Mr. Moynihan was a Managing Director in the Investment Banking division of TD Securities Inc.
Fred Woods Calgary, Alberta	President, Chief Executive Officer and Director	2004	Mr. Woods has been President, Chief Executive Officer and a Director of Midnight or its predecessor since July 2000. From March 1997 to May 2000, Mr. Woods was President and Chief Operating Officer of Ulster Petroleum Ltd. (an intermediate oil and gas company). Prior thereto, Mr. Woods was Executive Vice-President of Ulster Petroleum Ltd.
Anthony M. Lambert Calgary, Alberta	Director	2004	Mr. Lambert has been President, Chief Executive Officer of Daylight Energy Trust since December, 2004. On August 3, 2005 he resigned as Vice-President, Operations, Chief Operating Officer of Midnight. Mr. Lambert has been a Director of Midnight or its predecessor since July 2000. From August 1995 to May 2000, Mr. Lambert was the Vice-President, Operations of Ulster Petroleum Ltd.
Jay D. Squiers ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Dallas, Texas	Director	2004	Mr. Squiers has been a Managing Director of Fortress Investment Group, LLC. an investment and asset management firm, since August 2005 based in Dallas, Texas. Prior there to he was a Senior Vice-President of Prudential Capital Group, a private capital lender since 2002. Mr. Squiers began his career at Prudential Capital Group in 1991.
Tom J. Medvedic ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	2004	Mr. Medvedic is Vice-President, Finance and Chief Financial Officer of Calfrac Well Services Ltd. Mr. Medvedic was appointed Chief Financial Officer of Calfrac Well Services Ltd. in December 2004. Prior to July 2004, Mr. Medvedic was Treasurer of Ensign Resource Service Group Inc. Mr. Medvedic is a Chartered Accountant with a specialization in tax.
Judith A. Stripling Calgary, Alberta	Vice President, Finance and Chief Financial Officer		Ms. Stripling has been Vice-President, Finance and Chief Financial Officer of Midnight or its predecessor since July 2000. Prior thereto, Ms. Stripling was Vice-President, Finance and Chief Financial Officer of Ulster Petroleum Ltd.
Thomas F. Moslow Calgary, Alberta	Vice President, Exploration		Dr. Moslow has been Vice-President, Exploration of Midnight or its predecessor since July 2000. From 1997 to May 2000, Dr. Moslow was Chief Geologist and later Vice-President of New Ventures and Technology at Ulster Petroleum Ltd.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Randy Ford Calgary, Alberta	Vice President, Operations		Mr. Ford has been Vice-President, Operation of Midnight since June 15, 2005. From October 2000 to June 2005 Mr. Ford worked his way to the position of Group Leader of Drilling- Peace County and Bighorn Business Units with Encana (a senior oil and gas company) or its predecessor. From October 1996 to May 2000, Mr. Ford was Vice-President, Drilling & Completions at Ulster Petroleum Ltd.
Andrew D. Weldon Calgary, Alberta	Vice President, Land		Mr. Weldon has been Vice-President, Land of Midnight since February 2002. From March 1998 to January 2001, Mr. Weldon was Vice-President, Land at Startech Energy Inc. (an intermediate oil and gas company). Prior thereto, Mr. Weldon was the Land Manager of a predecessor company of Startech Energy Inc.
Chris von Vegesack Calgary, Alberta	Corporate Secretary		Mr. Vegesack has been a partner at Burnet, Duckworth & Palmer LLP, a Calgary based law firm, since 1986. Mr. Vegesack specializes in corporate finance and mergers and acquisitions. Mr. Vegesack has been the Corporate Secretary of Midnight or its predecessor since July, 2000.

Notes:

- (1) Member of the Audit Committee, Tom Medvedic is the Chairman of this committee.
- (2) Member of the Reserves Committee, Paul Moynihan is the Chairman of this committee.
- (3) Member of the Compensation Committee, Jay Squiers is the Chairman of this committee.
- (4) Member of the Corporate Governance Committee, Tom Medvedic is the Chairman of this committee. The Corporate Governance committee also reviews the technical services matters.
- (5) Midnight does not have an executive committee.
- (6) The terms of office of all directors of Midnight will expire on the date of the next annual meeting of shareholders of Midnight.

As at the date hereof, our directors and officers and their associates and affiliates, as a group, beneficially own, directly or indirectly, or exercise control or direction over, approximately 3,893,704 Common Shares representing 10.2% of our outstanding Common Shares. The directors and officers also hold 1,983,333 Warrants and 75,000 options which would increase their beneficial ownership to 14.3% of the outstanding Common Shares on a fully diluted basis. The information as to Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised, is based upon information received from such directors and officers.

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of Midnight has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person.

Penalties or Sanctions

No director, officer or promoter of Midnight, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of Midnight, or, to our knowledge, a shareholder holding sufficient securities of Midnight to affect materially the control of Midnight, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Conflicts

Certain of our directors and officers may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with our interests. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta). Mr. Moynihan, one of our directors, is a partner in an investment banking firm which provides services to us. Mr. von Vegesack, our Corporate Secretary, is a partner in a law firm which provides services to us. We periodically utilize the oilfield services of Calfrac Well Services Ltd. in its operations, of which Mr. Medvedic, one of our directors, is the Vice-President, Finance and Chief Financial Officer. Our board of directors does not believe that any activities undertaken by Mr. Moynihan, Mr. von Vegesack or Mr. Medvedic interfere, or could be perceived to interfere, in any material way with their ability to act with a view to our best interests.

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by us is accumulated and communicated to our management as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by our annual filings, that our disclosure controls and procedures are effective to provide reasonable assurance that material information related to us, is made known to them by others in our company. It should be noted that while our Chief Executive Officer and Chief Financial Officer believe that our disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

ESCROWED SECURITIES

To the knowledge of Midnight, none of our securities are held in escrow.

The Common Shares subscribed for in our initial private placement on November 29, 2004 were subject to a contractual hold period whereby 25% of the shares were released from such hold period on March 29, 2005 and the remaining 75% balance of the shares were released from such hold period on November 29, 2005.

In addition, a contractual hold period has been imposed on the former senior executives of MOG to hold any Common Shares subject to the following terms: 25% of the shares were released from the contractual hold period on March 31, 2005, an additional 37.5% are eligible for release on March 31, 2006 and the balance of the shares are eligible for release on March 31, 2007. These securities may be released from this contractual hold period earlier in certain circumstances with the consent of MOG's former financial advisor.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

We have established an audit committee to assist our Board of Directors in carrying out its oversight responsibilities with respect to financial reporting, internal controls and our external audit process. The Mandate and Terms of Reference of the Audit Committee is attached as Schedule "C".

Composition of the Audit Committee

The following table sets forth the name of each current member of the Audit Committee, whether such member is independent, financially literate and the relevant education and experience of such member.

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Tom J. Medvedic (Chairman)	Yes	Yes	Mr. Medvedic is Vice-President, Finance and Chief Financial Officer of Calfrac Well Services Ltd. As a Chartered Accountant, Mr. Medvedic has attained experience in preparing, analyzing and evaluating financial statements. Mr Medvedic has an understanding of the accounting principles used by Midnight as well as the implications of those accounting principles on Midnight's financial results. As a Chief Financial Officer of a public company, Mr. Medvedic is well informed of new accounting pronouncements and of best practises.
Paul E. Moynihan	Yes	Yes	Mr. Moynihan holds a Bachelor of Applied Science in Chemical Engineering from the University of Waterloo and a Master of Business Administration degree from the University of Western Ontario (Ivey). During his fourteen year career as an investment banker, Mr. Moynihan has obtained significant financial experience and exposure to mergers and acquisitions, capital markets, accounting and financial issues along with securities and other industry matters.
Jay D. Squiers	Yes	Yes	Mr. Squiers holds a law degree (Honors) from University of Texas, a Bachelor of Economics (magna cum laude) from Princeton and earned the Chartered Financial Analyst designation in 1997. Mr. Squiers has obtained significant financial experience and exposure to accounting and financial issues in his career at Prudential Capital Group. As a Senior Vice President, he was actively involved in originating, underwriting and managing a portfolio of private placement investments for that division of Prudential Financial, Inc. As a Managing Director of Fortress Investment Group, LLC. he is responsible for identifying, underwriting and executing debt acquisition and originating opportunities in the energy and general corporate sectors.

External Auditor Service Fees

Audit Fees

The audit fees consist of a budget for 2005 of \$55,000 payable to KPMG LLP for professional services rendered for the audit of our financial statements for the period ended December 31, 2005 and for services provided in connection with statutory and regulatory filings. In addition, professional services for quarterly reviews for 2005 of \$28,000 were paid to KPMG LLP.

Tax, Audit and Related Fees

We have paid \$30,000 to KPMG LLP for professional services of related fees (attendance at due diligence and audit for the business acquisition report) and \$1,200 for tax fees for the period ended December 31, 2005.

Pre-Approval of Policies and Procedures

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP as set forth in item 5 of the Audit Committee charter, under the heading "*Audit Committee Charter – Responsibilities and Duties*". The Audit Committee has approved the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, re-occurring or otherwise likely to be provided by KPMG LLP during the current fiscal year. The list of services is sufficiently detailed as to the particular services to be provided to ensure that the audit committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

LEGAL PROCEEDINGS

There are no legal proceedings which we are a party or of which any of our property is subject which is material to us and we are not aware of any such proceedings that are contemplated or pending.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last fiscal year and in any proposed transaction which has materially affected or would materially affect us, other than as disclosed herein.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP chartered accountants, Suite 1000, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

Valiant Trust Company at its principal offices in Calgary, Alberta is transfer agent and registrar of our Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, we have not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year but still in effect, other than the administrative and technical services agreement with Daylight dated November 29, 2004. A copy of this agreement has been filed on SEDAR at www.sedar.com.

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 us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our auditors. None of the designated experts of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Midnight.

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 us or of any associate or affiliate of us except for Chris von Vegesack, our Corporate Secretary, who is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

INDUSTRY CONDITIONS

The oil and 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 and British Columbia, 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 our 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 we are 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

In Canada, 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 exports may be made pursuant to export contracts with terms not exceeding one year in the case of oil other than heavy crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board of Canada ("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 license from the NEB and the issuance of such a license requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold 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 criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of two years or less or for a term of between 2 and 20 years (in quantities of not more than 30,000 m³ /d) may be made pursuant to an NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of Alberta and British Columbia also regulate the removal of natural gas 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 limits the ability to produce and to market natural gas production. The pro-rating of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade, and further 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 or in such other representative period as the parties may agree), (ii) impose an export price higher than the domestic price subject to an exception with respect to certain 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.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector 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 that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil, natural gas, natural gas liquids and sulphur 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 also subject to certain provincial taxes and royalties. Our operations which are not Crown lands and are subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and 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.

From time to time the governments of Canada and the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects, 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 allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "Technical Paper"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry (to a maximum of \$2,000,000) to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of ARTC that we will be required to include in federal taxable income will be 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

Alberta

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24 month, 8,000 m³ exemption is available to production from a reactivated well that has not produced for: (i) a 12 month period, if resuming production in October, November or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in

February 1993 or later. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12 month royalty exemption (to a maximum of \$1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 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%.

In Alberta, 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 gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural 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.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for oil at or below \$100 per cubic metre and 25% for prices above \$210 per cubic metre. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. The ARTC rate is currently applied to a maximum of \$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the applicable government department for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it would conduct a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than \$10,000 in royalties per year and non-corporate entities from qualifying from the program.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. 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). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on 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. 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.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "AEPEA"), which came into force on September 1, 1993 and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The AEPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations and significantly increase penalties. We are committed to meeting our 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 AEPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe 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 and 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. In April, 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ("LFEs"), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 mt, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of

experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August, 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased, although not material, expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment.

All government regulations and procedures will be followed in strict adherence to the law. We believe in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to us.

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 term future of the business.

Commodity Prices

Natural gas is a commodity influenced by factors within North America. The continued tight supply demand balance for natural gas is causing significant elasticity in pricing. Despite record drilling activity, a strong economy, weather, fuel switching and demand for electrical generation there still exists concerns about storage inventory levels and uncertainty in supply prospects. The current 12 month forward strip for natural gas at AECO is \$8.00/Mcf which exceeds our budgeted price of \$6.60/Mcf.

Crude oil is influenced by the world economy and OPEC's ability to adjust supply to world demand. Oil prices in 2003 and 2004 were kept high by political unrest and supply disruptions. More recently, higher world demands combined with lower inventory levels are responsible for the current price strength. The current 12 month forward strip for WTI is US\$55/bbl which exceeds our budgeted price of US\$42/bbl.

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. The cost of purchasing land and properties similarly increase 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.

Industry Consolidation and Competition

Over the past few years, consolidation within the Canadian oil and gas industry has resulted in a significant reduction of the number of junior to intermediate-sized exploration and production companies. American companies have also been acquiring companies and assets in Canada. The strength in commodity prices is expected to result in a continued high level of corporate and asset transactions as buyers strive to increase their asset base and sellers take advantage of high transaction prices.

Along with this merger and acquisition activity, a number of traditional exploration and production companies have recently converted into income or royalty trusts. This trend, which has increased competition for investment dollars and property acquisitions, is expected to continue in the near-term.

Strong commodity prices have increased operating cash flows leading to increased drilling activity. 2004 was another record year for the drilling and related service companies. This level of activity increases competition for oilfield goods and services and may cause drilling and operating costs to increase.

Capital Markets

Generally during the past two years, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry. We compete with the numerous new companies and their new stories in obtaining access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. Some companies will have to rely on internally generated funds to conduct their exploration and developmental programs.

RISKS AND UNCERTAINTIES

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by us will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Our long-term commercial success will depend on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that we will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, we may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues 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.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of our oil and gas reserves. We might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in our future net production revenue, causing a reduction in our oil and gas acquisition and development activities. In addition, bank borrowings available to us are expected to be determined in

part by our borrowing base. A sustained material decline in prices from historical average prices could limit our borrowing base, therefore reducing the bank credit available to us, and could require that a portion of any existing bank debt be repaid.

In addition to establishing markets for its oil and natural gas, we must also successfully market our oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by us will be affected by numerous factors beyond our control. We will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by us. Our ability to market our natural gas may depend upon our ability to acquire space on pipelines which deliver natural gas to commercial markets. We will also likely be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and 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. We have limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements; Liquidity

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

Our lenders are provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default, such as bankruptcy, these lenders may foreclose on or sell our properties. The proceeds of any such sale would be applied to satisfy amounts owed to our lenders and other creditors and only the remainder, if any, would be available to us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom, including many factors beyond Midnight's control. The reserve and associated cash flow information set forth herein represents 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 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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. 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, GLJ, our independent reserves evaluator, has used both constant and forecast price and cost estimates in calculating reserve quantities included herein. Actual future net revenue 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 revenues derived therefrom will vary from the estimates contained in the GLJ Report, and such variations could be material. The GLJ Report is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report. The GLJ Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in our resources since that date.

Reserve Replacement

Our future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on us successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves we may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. There can be no assurance that our future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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 us and may delay exploration and development activities.

Reliance on Operators and Key Employees

To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, our success will be largely dependent upon the performance of our management and key employees. We do not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of our management or any key employee could have a material adverse effect on us.

Assessments of Value of Acquisitions

Acquisitions of oil and gas issuers and oil and gas assets are typically based on engineering and economic assessments made by independent engineers and ours own assessments. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. In particular, the prices of and markets for oil and natural gas products may change from those anticipated at the time of making such assessments. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that we use for our year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by us. Any such instance may offset the return on and value of our Common Shares.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make 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 our ability to realize the anticipated growth opportunities and synergies from combining our acquired businesses and operations. The integration of an 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, as we grow, non-core assets may be disposed of, so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Competition

We actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than us. Our competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Our competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than us.

Certain of our customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply oil or gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Environmental Risks

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 international conventions and state and/or provincial and municipal 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 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 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 foreign governments and third parties and may require us to incur costs to remedy such discharge. 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 our financial condition, results of operations or prospects.

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 that may be amended from time to time. See "*Industry Conditions*." Our operations may require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at our projects and the obtaining of such licences and permits may delay our operations.

Third Party Credit Risk

We are or may be exposed to third party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from 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 our goods and services.

Aboriginal Claims

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

Title to Assets

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. It is our practice in acquiring significant oil and gas leases or interest in oil and gas leases to fully examine the title to the interest under the lease. In the case of minor acquisitions, we may rely upon the judgment of oil and gas lease brokers or landmen who perform the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. We believe that this practice is widely followed in the oil and gas industry. Nevertheless, there may be title defects which affect lands comprising a portion of our properties. To the extent title defects do exist, it is possible that we may lose all or a portion of our right, title, estate and interest in and to the properties to which the title relates.

Insurance

Our involvement in the exploration for and development of oil and gas properties may result in us becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although we have insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, we 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 such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects.

Changes in Legislation

The return on an investment in our securities is subject to changes in Canadian federal and provincial tax laws and government incentive programs and there can be no assurance that such laws or programs will not be changed in a manner that adversely affects us or the holding and disposing of our securities.

Accounting Write-Downs as a Result of GAAP

Canadian generally accepted accounting principles ("GAAP") requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in our financial statements. The accounting policies may result in non-cash charges to net income and write-down of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of our shares.

Under GAAP, the net amounts at which petroleum and natural gas costs are carried are subject to a test which is based in part upon estimated future net cash flow from reserves. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Conflicts of Interest

Our directors or officers 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 Midnight. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director or officer of a company who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with us 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 *Business Corporations Act* (Alberta).

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." Our exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject us to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada 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 in the *Climate Change and Emissions Management Act* (Alberta) (yet to be proclaimed), may require the reduction of emissions or emissions intensity produced by our operations and facilities. The direct or indirect costs of these regulations may adversely affect our business.

ADDITIONAL INFORMATION

Additional information relating to us may be found on SEDAR at www.sedar.com <<http://www.sedar.com>>. Additional information including remuneration of our directors and officers, principal holders of Common Shares and options to acquire Common Shares, is contained in our Information Circular - Proxy Statement dated March 15, 2005 and will be contained in our Information Circular - Proxy Statement for our Annual Meeting of Shareholders to be held on May 12, 2006 and further information in respect of financial matters is provided in our financial statements for the periods ended December 31, 2005 and 2004.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

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SCHEDULE A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (FORM 51-101 F3)

Management of Midnight Oil Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company'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, 2005 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, 2005 using constant prices and costs; and
- (b) (ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has:

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) 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
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company'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, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (c) 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.

Signed "Fred Woods"

Fred Woods, President and Chief Executive Officer

Signed "Paul Moynihan"

Paul Moynihan, Director and Chairman of the Reserves Committee

Signed "Tom Medvedic"

Tom Medvedic, Director and Member of the Reserves Committee

Signed "Jay Squiers"

Jay Squiers, Director and Member of the Reserves Committee

March 15, 2006

SCHEDULE B

REPORT ON RESERVES DATA (FORM 51-101 F2)

To the board of directors of Midnight Oil Exploration Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2005. The reserves data consist of the following:
 - (a)
 - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b)
 - (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and
 - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to total proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us for the period ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	February 1, 2006	Canada	\$nil	\$84,742	\$nil	\$84,742

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
7. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

GLJ Petroleum Consultants Ltd

Signed "Doug Sutton"

Doug R. Sutton, P. Eng

Vice President Corporate Evaluations

February 24, 2006

SCHEDULE C

MIDNIGHT OIL EXPLORATION LTD.

MANDATE AND TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Midnight Oil Exploration Ltd. ("Midnight") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and 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 on meeting their responsibilities in respect of the review and approval of the financial statements of Midnight and related documentation;
2. To provide a communication link between independent 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 shall be comprised of at least three (3) directors of Midnight, none of whom are members of management of Midnight and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110")) unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon;
2. The Board shall appoint the Committee Chair, who shall be an independent director; and
3. All of the members of the Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

1. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting;
2. The Committee shall satisfy itself on behalf of the Board with respect to Midnight's internal control systems and its ability to:
 - identify, monitor and mitigate business risks; and
 - ensure compliance with legal, ethical and regulatory requirements;

3. The primary responsibility of the Committee is to review the annual and interim financial statements of Midnight 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;
 - 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. The Committee is to 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 Midnight's disclosure of all other financial information;
5. With respect to the appointment of external auditors by the Board, the Committee shall:
 - 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 shall 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 Midnight 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 report to the Committee at the next scheduled meeting such pre-approval and the member 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 Midnight) their assessment of the internal controls of Midnight, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall 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 Midnight and its subsidiaries

7. The Committee shall review risk management policies and procedures of Midnight (eg. hedging, litigation and insurance)
8. The Committee shall establish a procedure for:
 - the receipt, retention and treatment of complaints received by Midnight regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Midnight of concerns regarding questionable accounting or auditing matters;
9. The Committee shall review and be apprised of any intent of Midnight regarding the hiring of partners and employees who work on Midnight's account and former partners and employees of the present and former external auditors of Midnight;
10. The Committee shall have the authority to investigate any financial activity of Midnight. All employees of Midnight are to cooperate as requested by the Committee; and
11. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Midnight without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every motion shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote;
2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting;
3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by 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 shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair;
5. The Committee shall 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. At each of these meetings, the Committee will have an "in-camera" session with the external auditors;
6. Agendas, approved by the Chair, shall 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 Midnight as it may see fit from time to time to attend at meetings of the Committee and assist thereat 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/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Midnight;
10. Any members of the Committee may be removed or replaced at any time by the Board and shall 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 shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee; and
11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.

Definitions – In this Charter:

"financially literate" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by Midnight's financial statements.