ENERNORTH INDUSTRIES INC.

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL & GAS INFORMATION

The following information is related to our reserves, future net revenue and discounted value of future net cash flow of oil and natural gas. Sproule Associates Limited ("Sproule"), independent qualified evaluators of Calgary, Alberta evaluated these reserves effective June 30, 2004. We used these reserves in the preparation of our Financial Statements for the fiscal year ended June 30, 2004.

All of the Company's Petroleum and Natural Gas reserves covered by this report are located in the Provinces of Alberta and Ontario, Canada.

All monetary references contained in this Statement of Reserves Data and Other Oil and Gas Information are in Canadian dollars unless otherwise specified.

In certain instances, numbers may not total due to computer-generated rounds. In such cases differences are not material.

FORWARD LOOKING STATEMENTS

This Statement of Reserves Data and Other Oil and Gas Information contain forward-looking statements. These statements relate to future events or EnerNorth's future performance. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur.

Although EnerNorth believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. EnerNorth cannot guarantee future results, levels of activity, performance, or achievements. Moreover, EnerNorth does not assume responsibility for the accuracy and completeness of the forward-looking statements.

Statements relating to "reserves" or "resources" are deemed 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. All forward-looking statements contained in this Statement of Reserves Data and Other Oil and Gas Information are expressly qualified by this cautionary statement. EnerNorth is not under any duty to update any of the forward-looking statements after the date hereof to conform such statements to actual results or to changes in EnerNorth's expectations.

GLOSSARY OF TERMS

Natural Gas		
	Mcf	1,000 cubic feet
	MMcf	1,000,000 cubic feet
	Mcf/d	1,000 cubic feet per day
	MMcf/d	1,000,000 cubic feet per day
	McfGE	oil to gas in the ratio of 1 barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf)
	Bcf	1,000,000,000 cubic feet
	GJ	Gigajoules
Oil and Natural Gas Liquids		
	Bbls	Barrels
	Mbbls	1,000 barrels
	Blpd	Barrels of liquid per day
	Boe	Barrels of oil equivalent using a conversion ratio of 6 Mcf to 1 bbl of oil.
	Mboe	1,000 boe
	Mmboe	1,000,000 boe
	Bpd	Barrels per day
	Boepd	Barrels of oil equivalent per day
	Bopd	Barrels of oil per day
	NGLs	Natural gas liquids
	Stb	Stock tank barrels of oil (oil volume at 60 degrees F and 14.65 pounds per square inch absolute)
	Mstb	1,000 stock tank barrels

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
Metres	cubic feet	35.494
Bbls	cubic metres	0.159
Cubic metres	Bbls	6.289
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

PART 1
DATE OF STATEMENT

Item 1.1 Relevant Dates:

1. Date of Statement: September 27, 2004
2. Effective Date of Statement: June 30, 2004
3. Preparation Date of Statement: September 20, 2004

PART 2
DISCLOSURE OF RESERVES DATA

Item 2.1 Reserves Data (Constant Prices and Costs):

1. Breakdown of Proved Reserves (Constant Case):

Table 1 attached– Constant Prices

2. Net Present Value of Future Net Revenue (Constant Case):

Table 2 attached – Constant Prices

3. Additional Information Concerning Future Net Revenue (Constant Case):

Table 3 attached – Constant Prices

Table 4 attached – Constant Prices

Item 2.2 Reserves Data (Forecast Prices and Costs):

1. Breakdown of Reserves (Forecast Case):

Table 1 attached – Forecast prices

2. Net Present Value of Future Net Revenue (Forecast Case):

Table 2 attached – Forecast prices

3. Additional Information Concerning Future Net Revenue (Forecast Case):

Table 3 attached – Forecast prices

Item 2.3 Reserves Disclosure Varies With Accounting:

Not Applicable

Item 2.4 Future Net Revenue Disclosure Varies With Accounting:

Not Applicable

PART 3
PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Estimates:

The oil, natural gas and natural gas by-products constant prices used in the evaluation are based on the June 30, 2004 posted price as determined by Sproule Associates Limited as follows:

Oil:	Edmonton Par	46.98 $/stb
Natural Gas:	Alberta AECO-C	6.62 $Mcf
Natural Gas By Products:	Pentanes Plus	46.24 $/bbl
	Propane	32.22 $/bbl
	Butanes	40.50 $/bbl
	Sulphur	40.00 $/lt

Item 3.2 Forecasted Prices Used in Estimates:

Table 5 attached – Forecast Prices

PART 4
RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

RECONCILATION OF THE COMPANY NET RESERVES BY PRINCIAPL PRODUCT TYPE BASED ON CONSTANT PRICES AND COSTS

The following table sets forth a reconciliation of the changes in EnerNorth's light and medium crude oil and natural gas liquids (Mbbl) and associated and non-associated gas (combined) (Mmcf) reserves as at June 30, 2004 against such reserves as at June 30, 2003 based on the constant price and cost assumptions.

	Light and Medium Oil			Associated and Non-Associated Gas		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)
At June 30, 2003	28.8	29.2	58.3	734.0	535.0	1,269.0
Extensions						
Improved Recovery						
Technical Revisions	(5.3)	(7.1)	(12.4)	(7.5)	(139.0)	(146.5)
Discoveries				489.0	65.0	554.0
Acquisitions						
Probable to Proved	4.8	(2.8)	2.0	15.6	38.7	54.3
Economic Factors						
Production	(4.4)		(4.4)	(81.1)	(1.7)	(82.8)
At June 30, 2004	23.9	19.6	43.5	1,150.0	498.0	1,648.0

RECONCILIATION OF THE CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10%
BASED ON CONSTANT PRICES AND COSTS

The following table sets forth changes between future net revenue estimates attributable to net proved reserves as at July 1, 2003 against such reserves as at June 30, 2004.

Canada	
Estimated Future Net Revenue at June 30, 2003	$4,704.0
Oil and Gas Sales During the Period, Net of Production Costs and Royalties	(276.1)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(437.9)
Changes in previously estimated development costs incurred during the period	-
Net change resulting from extensions and improved recovery	-
Net change resulting from discoveries	782.0
Changes resulting from acquisition of reserves	-
Changes resulting from disposition of reserves	-
Net Change resulting from revisions in quantity estimates	(431.9)
Net change in income taxes	-
Any other significant factors	340.9
Estimated Future Net Revenue at June 30, 2004	$4,681.0

PART 5
ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves:

1. Proved Undeveloped Reserves:

Not Applicable

2. Probable Undeveloped

The following table sets forth the Company's net volumes of probable undeveloped reserves that were attributed for each of our reserve categories. The Company commenced oil and gas operations during the financial year ended June 30, 2001.

	Light and Medium Oil and Natural Gas Liquids Net Probable (Mbbl)	Associated and Non-Associated Gas Net Probable (Mmcf)
June 30, 2001	-	226.0
June 30, 2002	5.5	524.0
June 30, 2003	-	488.0
June 30, 2004	10.6	288.30

Our undeveloped reserves at June 30, 2004 relates to three wells that are operated by a third party and require additional capital for pipeline and water disposal facilities in order to place on production. At the present time the capital costs required to tie these wells into production may not be not economic.

Item 5.2 Significant Factors or Uncertainties:

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economics 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 changes. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates, (iii) production decline rates, (iv) ultimate recovery of serves; (v) success of future development activities; (vi) marketability of production, (vii) effects of government regulation; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required for changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year–end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative. (For additional Risk Factors, please refer to the Company's annual Form 20F filed as an Annual Information Form on www.sedar.com).

Item 5.3 Future Development Costs:

The table below sets out future development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant and forecast prices and costs) and proved plus probable reserves (using forecast prices only) discounted by 10% (using forecast prices only).

Future Development Costs

($000's) Period	Total Proved Estimated Using Constant Prices	Total Proved Estimated Using Forecast Prices	Total Proved Plus Probable Estimated Using Forecast Prices	Total Proved Plus Probable Estimated Using Forecast Prices Discounted @10%
2004	40	40	166	149
2005			56	50

The future development costs are capital expenditures required in the future for the Company to convert probable reserves into proved developed reserves.

In the past the Company used its cash obtained from prior equity financings and its cash flow generated from the oil and gas division to develop its existing properties and fund new capital expenditures. The Company expects that its current cash flow from the oil and gas division to be sufficient to move its current probable reserves into a proved reserve category. Alternatively, the Company may look to farm out a portion of an interest in certain lands on favorable terms should the need arise. The Company may be required to find new equity issues in order to participate in any future acquisitions or exploration programs.

PART 6
OTHER OIL AND GAS INFORMATION

Item 6.1 Oil & Gas Properties and Wells:

Sibbald Property, Alberta: During the fiscal year 2004 the Company acquired through Alberta Crown land sales a 100% interest in 3 sections (1,920 net acres) and purchased 35 kilometers (22 miles) of seismic data. The Company currently has an interest in 10 sections or 6,400 gross acres (4,568 net acres) located in Townships 28 and 29, Range 2 W4M in the Sibbald Area approximately 160 miles east of Calgary, Alberta. The Company's wells are currently producing gas from the Bakken and Colony formations.

In May 2004 the Company re-entered and perforated the Colony zone in the 4-34-28-2 W4M well and placed the well on production on May 28, 2004. (The Company's 50% joint interest partner in is a penalty position in this well as they elected not to participate in the operations. Accordingly, the Company will retain 100% of the revenue until 300% of the joint venture partners share of capital costs are paid out to the Company).

In June 2004 the Company performed a 10 tonne sand frac in the Bakken formation in the 7-30-28-2 W4M well and placed the well on production June 25, 2004. (The Company's 37.5% joint interest partner is in a penalty position in this well as they elected not to participate in the operations. Accordingly, the Company will retain 100% of the revenue until 300% of the joint venture partners share of capital costs are paid out to the Company).

The Company held a 50% working interest in one section (640 gross acres – 320 net acres) of Crown land that expired in May 2004. As part of the expiry the Company abandoned the wellbore 10-2-29-2 W4M.

In May 2004 the Company commenced swabbing and testing of the Viking and Colony formations in the 6-28-28-2 W4M well. The Viking zone was wet and the Colony zone appears capable of production. The Company is currently evaluating pipeline tie in and compression of this well.

Farrow Property, Alberta: Effective January 2004 the Company exercised its Right of First Refusal and acquired a 68.5% working interest from three joint venture partners increasing the Company's working interest to 100% in the E 1/2 of Section 26-19-24 W4M (320 net acres). The Company is evaluating the replacement of a bottom hole pump for the 8-26-19-24 W4M well to place the oil well back on production. Effective May 1, 2004 the Company exercised an option and acquired a 33.33% working interest in Section 35-19-24 W4M (213 net acres). The Company and its partner are currently assessing a drill location on this section of land.

Olds Innisfail, Alberta: In fiscal 2003 the company participated in drilling and completing the 6-20-33-28 W4M Viking gas well. During fiscal 2004 the well was tied in and commenced production October 1, 2003. The Company has a 12.5% working interest in this well. In addition, the Company is currently participating for its 12.5% working interest in the tie in of a sour Viking gas well located 14-10-34-1 W45M.

Edson Property, Alberta: The Company has a 10% working interest in three (3) sections (1,920 gross acres) in the Edson area of Alberta. The Edson exploratory well 10-13-52-16W5M was spud on December 10, 2001, drilled to a depth of 3,149 meters (approximately 10,328 feet) to the Winterburn formation, and cased as a Winterburn Gas well shut in pending pipeline and water disposal facilities

DOE Area, Alberta: On August 13, 2003, the Company participated in Wabamun formation gas test well by paying 24% of the costs to drill to earn (i) a 24% interest before payout (subject to a 5-15% sliding scale convertible royalty), and a 15% interest after payout (ii) a 15% working interest in 9 sections (5,760 gross acres – 864 net) of multi formation prospective lands. The Company has also agreed to a 15% working interest in a 20 section (12,800 gross acre) Area of Mutual Interest ("AMI") around the test well area. The Wabamun well is currently suspended, waiting abandonment by the operator. On June 15, 2004 under the AMI the Company acquired a 15% working interest in two additional 2 sections (1,280 gross acres - 192 net). On July 7, 2004 after a geophysical and geological review the Company elected not to participate in the casing, completion and tie in of a lease preserving well and subsequently forfeited a 15% interest in 1 wellbore and 1 section (640 gross acres – 96 net) of land. In addition the Company further elected not to participate in the drilling of an additional well that is subject to 300% payout penalty provision in favor of the Operator. The Company currently has a 15% interest in 9 sections (5,760 gross acres-864 net acres).

*Prince Edward Island***:** In 2001 the Company acquired a 25% interest in (525,857 gross acres - 131,464 net) under permit for all hydrocarbons. In March 2003 the Operator of the PEI property drilled a gas test well on a permit offsetting the Company's interests and subsequently determined the well uneconomic and abandoned it. In June 2003, the Operator drilled a second gas test well on the same permit offsetting the Company's interest and extensive testing indicated that the well did not yield commercial volumes. Work on the wellbore has been suspended and the operator has claimed the Company's interest in the permits under circumstances that are disputed by the Company.

Brazeau River Property, Alberta: This prospect is comprised of 2 sections of land (1,280 gross acres). During fiscal 2002, the Company participated in the re-entry of a cased well bore 2-28-47-12 W5M by paying a 50% interest before payout, to earn a 25% interest after payout in the well bore and lands. The development well was re-entered and tested in the Rock Creek and Elkton formation and completed as a Rock Creek oil well. The well is currently shut in pending economic evaluation of pipeline tie in.

Bigstone & Kaybob Properties, Alberta: The Bigstone property is located in Township 61 Range 22 W5M in Alberta. The Company holds an average 20% interest in approximately (640 gross acres) of land. One well at Bigstone is currently producing natural gas and liquids. The Company has an 18% to 20% working interest in approximately (1920 gross acres) of land located in Township 61, Range 19 and 21 W5M. There are currently three wells producing natural gas and liquids.

2. The following table sets out the number of gross and net Producing oil and natural gas wells and the number of gross and net Non-Producing oil and natural gas wells that the Company has an interest in by location.

Location	Gross Producing Gas Wells	Net Producing Gas Wells	Gross Non-Producing Gas Wells	Net Non-Producing Gas Wells	Gross Producing Oil Wells	Net Producing Oil Wells	Gross Non-Producing Oil Wells	Net Non-Producing Oil Wells
Alberta	9	3.5	10	2.25	-	-	2	1.25
Ontario	1	0.11	-	-	2	0.29	1	0.22

Item 6.2 Properties With No Attributed Reserves:

1. The Company has an interest in 7,040 gross acres (1,157 net acres) of land with no attributed reserves located in Alberta, Canada. The lands are operated by a third party and the Company is not aware of any work commitments as of the date of this report.

2. The 7,040 gross acres (1,157 net acres) of land with no attributed reserves of which the Company has an interest, 1,280 gross acres (176 net acres) will expire prior to fiscal 2005 unless the lands are continued.

Item 6.3 Forward Contracts:

The Company has no forward contracts.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs:

The Company bases its estimates for costs of abandonment and reclamation of surface leases and wells on previous experience with similar well site locations. The total of such costs for financial statement purposes was $135,819. The Company believes that its estimates of $30,000 gross per well for abandonment and reclamation costs are reasonable and applicable to its wells. The independent evaluator therefore used them in the estimate of net revenue. Ultimately all wells will require abandonment and reclamation. A provision of $216,000 undiscounted is included in the estimates of future net revenue for the abandonment of 7.44 net wells ($94,671 discounted by 10%). Of the $216,000 provision the Company expects to pay $71,000 in abandonment over the next 3 financial years.

Item 6.5 Tax Horizons:

The Company and its subsidiaries have non-capital losses of approximately $9,006,022 that are available to reduce future taxable income. The Company also has Cumulative Canadian oil and gas property expenses of $6,773,378 and capital loss carry forwards of $10,231,641. The tax reserves are more than the future undiscounted net revenues to be derived from the oil and gas reserves. As a result the expected future tax payable is nil.

Item 6.6 Costs Incurred:

1. (a) During the financial year ended June 30, 2004, the Company’s unproved property acquisition costs were $230,081and proved property acquisition costs were $220,000.
   (b) During the financial year ended June 30, 2004 the Company incurred exploration costs of $785,639.
   (c) During the financial year ended June 30, 2004 the Company’s development costs were $504,434.

2. Not Applicable.

Item 6.7 Exploration and Development Activities:

1. Drilling Activity. As of June 30, 2004 the Company, through the Oil & Gas Division had the following drilling activities. A gross well is a well in which an interest is owned. The number of net wells represents the sum of a fractional interest the Company owns in gross wells.

Number of Exploratory gas wells drilled	**2004**	
	Gross	**Net**
Abandoned	1	.24
Suspended *	1	.24

* Suspended well is pending abandonment.

2. Refer to Part 6.1 (Other Oil and Gas Information).

Item 6.8 Production Estimates:

1. The following tables sets forth the volume of production by product type estimated for the first year reflected in the constant price case of future net revenue.

	Light/Medium Oil and Natural Gas Liquids (Mbbl)	Associated and Non Associated Gas (Mmcf)
June 30, 2005	4.0	134.5

2. The following table reflects the fields that represents 20% or more of the volume of production estimated for the first year reflected in the constant price case of future net revenue.

June 30, 2005	Light/Medium Oil and Natural Gas Liquids (Mbbl)	Associated and Non Associated Gas (Mmcf)
Farrow, Alberta	2.5	
Kaybob, Alberta		31.5
Sibbald, Alberta		79.5

Item 6.9 Production Histories:

1. The following table sets forth certain information in respect of production, product prices received, production costs and netbacks received by the Company for each quarter of fiscal 2004.

	Three Months Ended September 30, 2003	Three Months Ended December 31, 2003	Three Months Ended March 31, 2004	Three Months Ended June 30, 2004
Average Daily Production				
Light and Medium Oil (bbl/d)	4.97	8.18	2.36	3.48
Natural Gas Liquids (bbl/d)	5.92	7.37	7.62	9.39
Natural Gas (Mcf/d)	212.22	163.33	125.56	368.51
Average Net Prices Received				
Light and Medium Oil ($/bbl)	$ 40.36	$ 38.36	$ 35.97	$ 33.02
Natural Gas Liquids ($/bbl)	$ 31.85	$ 33.50	$ 30.77	$ 22.76
Natural Gas ($/Mcf)	$ 6.24	$ 7.77	$ 7.65	$ 6.05
Royalties				
Light and Medium Oil ($/bbl)	$ 6.61	$ 5.30	$ 2.13	$ 1.85
Natural Gas Liquids ($/bbl)	$ 8.38	$ 7.94	$ 5.78	$ 3.95
Natural Gas ($/Mcf)	$ 1.00	$ 1.51	$ 1.46	$ 0.65
Production Costs				
Light and Medium Oil ($/bbl)	$ 11.99	$ 9.73	$ 12.18	$ 11.72
Natural Gas Liquids ($/bbl)	$ 15.02	$ 14.20	$ 13.02	$ 14.24
Natural Gas ($/Mcf)	$ 2.63	$ 3.32	$ 3.08	$ 2.30
Netbacks Received				
Light and Medium Oil ($/bbl)	$ 21.76	$ 23.33	$ 21.66	$ 19.45
Natural Gas Liquids ($/bbl)	$ 8.45	$ 11.36	$ 11.97	$ 4.57
Natural Gas ($/Mcf)	$ 2.61	$ 2.94	$ 3.11	$ 3.10

2. The following table indicates the Company's total production for fiscal 2004 from its core properties.

	Natural Gas Liquids (Mbbl)	**Natural Gas (Mmcf)**
Sibbald, Alberta	-	21.91
Kaybob, Alberta	1.79	5.81

Table 1
NI 51-101
Summary of Oil and Gas Reserves as of June 30, 2004

Constant Prices and Costs

Reserves

	Light & Medium Oil		Heavy Oil		Natural Gas (Non-Associated & Associated)		Natural Gas (Solution)		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	1.7	1.6	0.0	0.0	1,063	937	0	0	7.9	5.5
Developed Non-Producing	20.9	16.1	0.0	0.0	251	215	0	0	1.1	0.8
Undeveloped	0.0	0.0	0.0	0.0	0	0	0	0	0.0	0.0
Total Proved	**22.6**	**17.7**	**0.0**	**0.0**	**1,314**	**1,151**	**0**	**0**	**9.0**	**6.2**
Probable	14.9	11.5	0.0	0.0	633	499	0	0	11.5	7.9
Total Proved Plus Probable	**37.5**	**29.2**	**0.0**	**0.0**	**1,948**	**1,651**	**0**	**0**	**20.4**	**14.1**

Reference: Item 2.2(1) of Form 51-101F1

Table 2
NI 51-101
Summary of Net Present Values of Future Net Revenue as of June 30, 2004

Constant Prices and Costs

	Net Present Values of Future Net Revenue				
	Before Income Taxes Discounted at (%/Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved					
Developed Producing	4,723	3,102	2,341	1,909	1,631
Developed Non-Producing	1,317	1,143	1,008	901	814
Undeveloped	0	0	0	0	0
Total Proved	**6,041**	**4,246**	**3,349**	**2,810**	**2,446**
Probable	2,927	1,849	1,332	1,034	841
Total Proved Plus Probable	**8,967**	**6,095**	**4,681**	**3,844**	**3,287**

Reference Item 2.2(2) of Form 51-101F1

Notes:

- NPV of FNR include all resource income:
  - Sale of oil, gas, by-product reserves
  - Processing third party reserves
  - Other income
- Discount Rates:
  - Constant case, 0, 10 percent per year
  - Forecast prices and costs, 0, 5, 10, 15, 20 percent per year
- After tax has not been included at the request of the Company. The Company has informed Sproule that it anticipates being in a non-taxable position for the life of the Company's remaining reserves.

Table 3
NI 51-101
Total Future Net Revenue
(Undiscounted)
as of June 30, 2004

Constant Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Proved Reserves	9,705	1,158	2,302	40	165	6,041
Total Proved Plus Probable	15,057	2,062	3,621	221	186	8,967

Reference Item 2.2(3)(b) of Form 51-101F1

Table 4
NI 51-101
Net Present Value of Future Net Revenue
by Production Group
as of June 30, 2004

Constant Prices and Costs

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)**
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	327
	Heavy Crude Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	2,835
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	535
	Heavy Crude Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	3,820

Reference Item 2.1(3)(c) of Form 51-101F1

Table 1
NI 51-101
Summary of Oil and Gas Reserves
as of June 30, 2004

Forecast Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	1.7	1.6	0.0	0.0	1,060	935	0	0	7.9	5.5
Developed Non-Producing	20.5	15.8	0.0	0.0	251	215	0	0	1.1	0.8
Undeveloped	0.0	0.0	0.0	0.0	0	0	0	0	0.0	0.0
Total Proved	**22.2**	**17.4**	**0.0**	**0.0**	**1,312**	**1,149**	**0**	**0**	**9.0**	**6.2**
Probable	14.6	11.3	0.0	0.0	632	498	0	0	11.4	7.9
Total Proved Plus Probable	**36.8**	**28.7**	**0.0**	**0.0**	**1,944**	**1,647**	**0**	**0**	**20.4**	**14.1**

Reference: Item 2.2(1) of Form 51-101F1

Table 2
NI 51-101
Summary of Net Present Values of Future Net Revenue as of June 30, 2004

Forecast Prices and Costs

	Net Present Values of Future Net Revenue				
	Before Income Taxes Discounted at (%/Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved					
Developed Producing	3,863	2,597	2,013	1,684	1,473
Developed Non-Producing	964	874	799	737	684
Undeveloped	0	0	0	0	0
Total Proved	**4,827**	**3,471**	**2,812**	**2,421**	**2,157**
Probable	2,264	1,412	1,020	800	658
Total Proved Plus Probable	**7,091**	**4,883**	**3,832**	**3,220**	**2,815**

Reference Item 2.2(2) of Form 51-101F1

Notes:

- NPV of FNR include all resource income:
  - Sale of oil, gas, by-product reserves
  - Processing third party reserves
  - Other income
- Discount Rates:
  - Constant case, 0, 10 percent per year
  - Forecast prices and costs, 0, 5, 10, 15, 20 percent per year
- After tax has not been included at the request of the Company. The Company has informed Sproule that it anticipates being in a non-taxable position for the life of the Company's remaining reserves.

Table 3
NI 51-101
Total Future Net Revenue
(Undiscounted)
as of June 30, 2004

Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Proved Reserves	8,724	894	2,757	40	206	4,827
Total Proved Plus Probable	13,407	1,546	4,311	222	236	7,091

Reference Item 2.2(3)(b) of Form 51-101F1

Table 4
NI 51-101
Net Present Value of Future Net Revenue by Production Group as of June 30, 2004

Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	210
	Heavy Crude Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	2,455
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	356
	Heavy Crude Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	3,232

Reference Item 2.1(3)(c) of Form 51-101F1

Table 5
NI 51-101
Summary of Pricing and Inflation Rate Assumptions as of June 30, 2004

Forecast Prices and Costs

	Oil							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical[4]								
2000	30.30	44.03	28.61	5.07	46.27	34.83	1.5	0.674
2001	25.94	39.06	18.05	6.23	42.46	27.93	2.0	0.646
2002	26.09	40.12	27.58	4.04	40.80	25.39	2.7	0.637
2003	31.14	43.23	27.39	6.66	44.16	34.55	2.5	0.716
Forecast								
2004	38.49	49.81	32.07	7.64	51.02	37.13	1.5	0.750
2005	35.40	45.71	29.75	7.22	46.81	34.07	1.5	0.750
2006	29.59	37.99	25.92	5.76	38.90	26.90	1.5	0.750
2007	26.14	33.37	21.33	4.91	34.17	23.63	1.5	0.750
2008	26.53	33.87	21.84	4.98	34.69	23.98	1.5	0.750
Thereafter				Various Escalation Rates				

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) Item 3.2(1)(b) of Form 51-101F1 also requires disclosure of the *reporting issuer's* weighted average historical prices for the most recent financial year (2003, in this example).

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of EnerNorth Industries Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at June 30 , 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at June 30, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserve quantities were estimated as at June 30, 2004 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.

   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).

3. 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.

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of June 30, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of EnerNorth Industries Inc., as of June 30, 2004, prepared July and August 2004	Canada				
Total			**Nil**	**3,832**	**Nil**	**3,832**

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
August 25, 2004

James D. Hudson, R.P.T. (Eng.)
Project Leader & Shareholder

M. Maughan.

Michael W. Maughan, C.P.G., P.Geol.
Manager, Geoscience, & Associate

L Precul

Lucia M. Precul, P.Eng.
Senior Petroleum Engineer

Ken H. Crowther, P.Eng.
President

ENERNORTH INDUSTRIES INC.
FORM 51-101F3
STATEMENT OF RESERVES DATA
REPORT OF MANAGEMENT AND DIRECTORS
September 20, 2004

Management of EnerNorth Industries Inc. ("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 June 30, 2004 using the forecast prices and costs; and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at June 30, 2004 using constant prices and costs; and
(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 will be filed with securities regulatory authorities concurrently with this report.

The Petroleum and Natural Gas Reserve 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;

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Petroleum and Natural Gas Reserve Committee of the board of directors has reviewed the Company's procedure for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management.

The board of directors has approved

(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.

"SANDRA J. HALL"
Sandra J. Hall, President and Director

"JAMES C. CASSINA"
James C. Cassina, Chairman and Director

"IAN DAVEY"
Ian Davey, Director

"MILTON KLYMAN"
Milton Klyman, Director

"RAMESH K. NAROOLA"
Ramesh K. Naroola, Director

September 27, 2004