FORM 51-102F3

MATERIAL CHANGE REPORT

Item 1. **<u>Name and Address of Issuer:</u>**

Argo Energy Ltd.("Argo")
750, 330 – 5th Avenue S.W.
Calgary, Alberta
T2P 0L4

Item 2. **<u>Date of Material Change</u>:**

July 30, 2004

Item 3. **<u>News Release:</u>**

Argo issued a news release respecting the material change described herein on July 30, 2004.

Item 4. **<u>Summary of Material Change:</u>**

The previously announced plan of arrangement (the "Arrangement") involving Argo and Energy North Inc. ("Energy North") was completed effective July 30, 2004.

Item 5. **<u>Full Description of Material Change:</u>**

At a special meeting of the Energy North shareholders and option holders held on July 30, 2004, the shareholders and option holders of Energy North approved the Arrangement, subsequent to which the Court of Queen's Bench of Alberta granted the final order approving the Arrangement.

Pursuant to the Arrangement, all outstanding common shares of Energy North were transferred to Argo and Energy North became a wholly-owned subsidiary of Argo. The shareholders of Energy North received, for each outstanding common share of Energy North held by them, 0.3084 of a common share of Argo. Also a total of 150,000 options of Energy North were arranged (and acquired by Argo). A total of 16,944,095 Argo common shares were issued pursuant to the Arrangement.

After giving effect to the Arrangement, Argo has outstanding approximately 52.0 million common shares (basic) and 57.9 million fully diluted common shares and net debt of approximately $34 million.

Application was made to delist the Energy North common shares from trading on the Toronto Stock Exchange ("TSX") and application was made to the applicable securities regulatory authorities for Energy North to cease to be a reporting issuer under the applicable securities laws in the jurisdictions of Alberta, British

Columbia and Ontario. The common shares of Argo began trading on the TSX on Thursday, August 5, 2004.

A report of reserves data and other oil and gas information as required under item 1 of section 2.1 of the Canadian Securities Administrators' National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**") for Argo (the "**Argo 51-101 Report**") was filed on SEDAR on April 29, 2004. The Argo 51-101 Report is derived from the report prepared by AJM Petroleum Consultants in accordance with NI 51-101 and the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the properties of Argo as of December 31, 2003. A summary of the Argo 51-101 Report is provided the information circular dated July 2, 2004 of Energy North (the "**Information Circular**") at pages A-9 to A-22 under the heading "Statement of Reserves Data and Other Oil and Gas Information" which was prepared in connection with the Arrangement.

Pursuant to the Arrangement, Argo acquired the crude oil, natural gas liquids and natural gas reserves of Energy North. A report of reserves data and other oil and other oil and gas information as required under item 1 of section 2.1 of NI 51-101 for Energy North (the **"Energy North 51-101 Report")** was filed on SEDAR on May 20, 2004 and July 2, 2004. The Energy North 51-101 Report is derived from the report prepared by Sproule Associates Limited in accordance with NI 51-101 and the standards contained in the COGE Handbook and evaluates the crude oil, natural gas liquids reserves attributable to the properties of Energy North as of December 31, 2003. A summary of the Energy North 51-101 Report is provided at pages B-7 to B-21 of the Information Circular under the heading "Statement of Reserves Data and Other Oil and Gas Information". Forms 51-101F1 and 51-101F2 which were filed on May 20, 2004 and 51-101F3 which was filed on July 2, 2004 are attached as Schedule "A" hereto.

The following discusses Argo's reasonable expectation of how the Arrangement (thereby being the acquisition of the Energy North properties), had it occurred prior to December 31, 2003 (the effective date of the Argo 51-101 Report), would have affected the reserves data or other information contained the Argo 51-101 Report. Based on the fact that: (1) the Argo 51-101 Report and the Energy North 51-101 Report were prepared in accordance with NI 51-101 and the COGE Handbook standards and definitions, and; (2) there are no common properties of Argo and Energy North (thereby creating material adjustments to development, capital or other costs) management reasonably expects that the crude oil, natural gas and natural gas liquids reserves attributable to the properties of Energy North as at December 31, 2003 as provided in the Energy North 51-101 Report could have been combined with those of Argo as provided in the Argo 51-101 Report.

The following table lists the heading of each of the tables required under item 1 of section 2.1 of NI 51-101 for each of Argo and Energy North respectively. (Argo uses titles for the tables in the Argo 51-101 Report and Energy North numbered its tables in the Energy North 51-101 Report and are listed below to correspond to those in the Argo 51-101 Report). The amounts stated in each such table would have been combined had the Arrangement occurred prior to December 31, 2003, as follows:

Argo **NI 51-101 Tables**		**Energy North** **NI 51-101 Tables**
Reserve Estimation and Economic Evaluation – Forecast Prices and Costs		Table 1
Net Present Values of Future Net Revenue Before Income Tax		Table 2
Reserve Estimation and Economic Evaluation – Constant Prices and Costs		Table 1
After Income Tax		Table 2
Total Future Net Revenue as at December 31, 2003 and estimated Production for Year Ended December 31, 2004 (forecast and constant prices are 2 columns in the same table)		Table 3
Future Net Revenue by Production Group (forecast and constant prices are 2 columns in the same table)		Table 4
Pricing Assumptions		Table 5 and Table 6
Reconciliation of Changes in Reserves		Table 8
Reconciliation of Changes in Net Present Values of Future Net Revenues		Table 7
Additional Information Relating to Reserves Data (1)		Additional Information Relating to Reserves Data

Note:

(1) The information provided under Additional Information Relating to Reserves Data for Argo would be combined with the information provided under each respective subheading in the Energy North 51-101 Report (see pages 1 to 4 inclusive of Schedule "A" hereto) except for the disclosure under the heading "Additional Information Relating to Reserves Data - Tax Horizons" which would be replaced as follows:

"Argo has tax pools of approximately $16 million as at December 31, 2004 which are expected to shelter the Company from being cash taxable until early in 2005, assuming current industry conditions prevail."

Item 6. **Reliance on subsection 7.1(2) or (3) of National Instrument 51-102**

Not applicable.

Item 7. **Omitted Information:**

Not applicable.

Item 8. **Executive Officer:**

Bradley Johnson, Chief Executive Officer
Telephone: (403) 770-6317

Item 9. **Date of Report**

August 9, 2004

SCHEDULE "A"

ENERGY NORTH INC.

May 19, 2004

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION
FORM NI 51-101 F1

Energy North Inc. ("the Company") with this and other filings (including 2003 Annual Report, quarterly Interim Reports for 2003 and 2003 audited Financial Statements) provides disclosure of its oil and gas activities in accordance with National Instrument 51-101. All disclosures should be considered together. The Company's oil and gas activities are all in Canada.

The information contained herein supplements the reserves data found in the 2003 Annual Report. Sproule Associates Limited provided a report on (January 1, 2003) relating to their reserve and economic evaluation of the oil and gas properties owned by the Company as of (January 1, 2004). All data is as of December 31, 2003.

The following tables are attached:

1.) Summary of Oil and Gas Reserves, Constant and Forecast Prices and Costs
2.) Summary of Net Present Values, Constant and Forecast Prices and Costs
3.) Total Future Net Revenue (Undiscounted), Constant and Forecast Prices and Costs
4.) Future Net revenue by Production Group, Forecast Prices and Costs
5.) Summary of Pricing and Inflation Rate Assumptions, Crude Oil, Natural Gas & By-Products Constant Prices and Costs, prepared by independent reserves evaluator, Sproule Associates Limited
6.) Summary of Pricing and Inflation Rate Assumptions, Crude Oil, Natural Gas & By-Products Forecast Prices and Costs, prepared by independent reserves evaluator, Sproule Associates Limited.
7.) Company Net Revenue Reconciliation
8.) Reconciliation of Reserves
9.) Future Development Costs
10.) Summary of 2003 Operations by Quarter

Undeveloped Reserves

The Company has 0.656 billion cubic feet of natural gas of proved undeveloped reserves. 0.222 billion cubic feet of these reserves are associated with shallow gas bearing zones in the Medallion area which lie above currently producing zones and will be produced once the deeper zones have been depleted. 0.411 billion cubic feet of proved undeveloped reserves are associated with one well in the Markerville area of Alberta which was drilled but not producing by year end 2003.

Future Development Costs

Funding of Future development is expected to be from internally generated cash flow and incremental bank debt. Incremental cost of funds is not expected to materially affect reserves or net revenue.

Energy North Inc.
2003 Oil and Gas Wells

Producing Wells				Non Producing Wells (SI and Suspended)			
Oil		Gas		Oil		Gas	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
43	37.5	47	19.5	37	29.5	49	22.5
0	0	0	0	1	0.5	0	0
43	37.5	47	19.5	38	30	49	22.5

Properties With No Reserves Assigned

The Company has interests in approximately 85,000 acres of undeveloped land (51,000 acres net). Of these, rights to 6,729 acres (3,276 acres net) are expected to expire in 2004.

Abandonment and Reclamation Costs

The Alberta Energy and Utilities publishes estimates of abandonment and reclamation costs for various types of wells that are utilized in its Licensee Liability Rating program. The Company considers these estimates to be 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 $1,769,000 (undiscounted) is included in the estimates of future net revenue, $878,000 discounted at 10%.

Costs to abandon and reclaim pipelines and facilities are not included in the evaluation; these costs are expected to be offset in the aggregate by proceeds from the sale of surface equipment.

In the next three years the Company expects to incur $104,000 (undiscounted) in abandonment and reclamation costs.

Tax Horizon

The Company had previously forecast that its tax pools would not be sufficient to maintain its taxable income at NIL and that it may be subject to current income taxes in 2004. The Company has revised its forecast and does not now expect to pay current income taxes in 2004. It is not known when current taxes will be payable, as it depends on reinvestment, results and utilization of existing and future tax pools.

Costs Incurred 2003

Property acquisitions	$1,747,000
Exploration costs	$3,329,000
Development costs	$4,261,000
Total	**$9,337,000**

Exploration and Development Activities

Wells drilled in 2003

	Gas		Oil		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development	5	0.925	3	375	2	1.5	10	2.80
Exploration	15	11.220	0	0	0	0	15	11.22
Total	20	12.145	3	375	2	1.5	25	14.02

Production estimates

Estimated Company working interest (gross) production for 2004 in the independent evaluation:

	Oil [bopd]	**Gas [mcf/d]**	**Natural Gas Liquids [bopd]**	**Total BOE [BOE/d]**
Total Proved	245	5,323	129	1,261
Proved + Probable	256	5,980	138	1,381
Property exceeding 20%				
Proved	75	1,510	97	424
Proved + Probable	84	1,581	101	448

2003 Annual Production by Field:

Area	Oil Bbls	NGL Bbls	Gas Mcf	BOE
St. Albert	38,907	40,699	608,243	180,980
Sounding Lake	69,638	1,777	110,425	89,820
Sylvan Lake	410	2,887	242,435	43,703
Medallion	29	724	190,692	32,535
Vulcan	0	173	99,105	16,691
Zama	28	513	86,770	15,003
Alexander	802	0	35,112	6,654
Vega	0	126	34,171	5,822
Cadogan	0	0	25,687	4,281
Esther	0	0	24,853	4,142
Innisfail	186	149	13,692	2,617
Coronation	0	9	13,198	2,209
Knopck	89	8	11,931	2,085
Trochu/Ghost Pine	28	246	7,533	1,530
Sturgeon Lake	685	57	841	882
Bistcho	669	0	0	669
Twining	79	8	160	113
Herronton	13	0	437	85
Total	**111,562**	**47,377**	**1,505,284**	**409,820**

TABLE 1

NI 51-101
Summary of Oil and Gas Reserves
as of December 31, 2003
Forecast Prices and Costs
Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved								
Developed Producing	149.6	131.9	181.5	167.7	6,133	5,043	198.5	168.7
Developed Non Producing	13.1	9.4	-	-	13	9	0.8	0.6
Undeveloped	26.4	22.9	-	-	683	565	13.9	11.7
Total Proved	**189.1**	**164.2**	**181.5**	**167.7**	**6,829**	**5,617**	**213.2**	**181.0**
Probable	60.2	50.3	85.1	78.3	3,903	3,240	89.9	75.2
Total Proved Plus Probable	**249.3**	**214.4**	**266.6**	**246**	**10,732**	**8,857**	**303.1**	**256.3**

(1) Includes solution gas

NI 51-101
Summary of Oil and Gas Reserves
as of December 31, 2003
Constant Prices and Costs
Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved								
Developed Producing	176.3	156.4	230.7	213.5	6,197	5,088	198.5	168.8
Developed Non Producing	13.1	9.2	-	-	13	9	0.8	0.6
Undeveloped	26.4	22.9	-	-	684	565	13.9	11.7
Total Proved	**215.8**	**188.5**	**230.7**	**213.5**	**6,894**	**5,662**	**213.3**	**181.1**
Probable	60.3	50	107.1	98.7	3,940	3,262	90.3	75.5
Total Proved Plus Probable	**276.1**	**238.5**	**337.8**	**312.2**	**10,834**	**8,924**	**303.6**	**256.5**

(1) Includes solution gas

TABLE 2

NET PRESENT VALUE OF FUTURE NET REVENUE
FORECAST PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
Proved										
Developed Producing	23,156	20,430	18,453	16,945	15,751	18,913	16,595	14,912	13,634	12,625
Developed Non - Producing	237	207	183	163	147	152	131	113	99	87
Undeveloped	1,713	1,428	1,210	1,039	902	1,183	966	793	659	551
Total Proved	**25,106**	**22,065**	**19,846**	**18,148**	**16,800**	**20,261**	**17,692**	**15,818**	**14,391**	**13,263**
Probable	14,362	10,792	8,559	7,050	5,971	9,568	7,176	5,681	4,671	3,949
Total Proved Plus Probable	**39,467**	**32,857**	**28,405**	**25,198**	**22,771**	**29,841**	**24,867**	**21,499**	**19,062**	**17,212**

NET PRESENT VALUE OF FUTURE NET REVENUE
CONSTANT PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)			AFTER INCOME TAXES DISCOUNTED AT (%/year)		
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)
Proved						
Developed Producing	29,499	25,779	23,038	22,990	20,021	17,848
Developed Non - Producing	278	242	213	173	147	127
Undeveloped	2,384	1,990	1,690	1,693	1,379	1,143
Total Proved	**32,160**	**28,010**	**24,940**	**24,855**	**21,548**	**19,118**
Probable	18,496	13,863	10,938	12,285	9,187	7,232
Total Proved Plus Probable	**50,656**	**41,874**	**35,879**	**37,140**	**30,735**	**26,350**

TABLE 3

Total Future Net Revenue
(Undiscounted)
as of December 31, 2003
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	50,316	8,538	14,110	970	1,592	25,106	4,845	20,261
Total Proved Plus Probable	77,123	13,088	21,367	1,432	1,769	39,467	9,627	29,841

NI 51-101
Total Future Net Revenue
(Undiscounted)
as of December 31, 2003
Constant Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	60,587	10,202	15,803	968	1,454	32,160	7,305	24,855
Total Proved Plus Probable	92,399	15,778	22,967	1,421	1,577	50,656	13,516	37,140

TABLE 4

NI 51-101
Net Present Value of Future Net Revenue
by Production Group
as of December 31, 2003
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 other by-products)	1,253
	Heavy Oil (including solution gas and other by-products)	655
	Natural Gas (including solution gas and other by-products)	10,916
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,689
	Heavy Oil (including solution gas and other by-products)	941
	Natural Gas (including solution gas and other by-products)	15,392

NI 51-101
Net Present Value of Future Net Revenue
by Production Group
as of December 31, 2003
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 other by-products)	2,589
	Heavy Oil (including solution gas and other by-products)	2,045
	Natural Gas (including solution gas and other by-products)	19,792
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	3,383
	Heavy Oil (including solution gas and other by-products)	2,666
	Natural Gas (including solution gas and other by-products)	28,564

TABLE 5

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	Oil			Natural Gas Liquids and Sulphur						
Year	WTI CUSHING OKLAHOMA ($US/bbl)	Edmonton Par Price 40 degree API ($Cdn/bbl)	Hardisty Bow River $Cdn/bbl	Natural Gas [1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Edmonton Propane FOB Field Gate ($Cdn/bbl)	Plant Gate Sulphur (Mlt)	Inflation Rate [2] (%/Year)	Exchange Rate[3] ($US/$Cdn)
Historical [4]										
2000	30.30	44.03	34.49	5.07	46.27	34.83	31.34	14.14	1.50	0.674
2001	25.94	39.06	25.04	6.23	42.46	27.93	29.87	-2.26	2.00	0.646
2002	26.09	40.12	31.85	4.04	40.80	25.39	20.36	12.71	2.70	0.637
2003	31.13	43.21	32.95	6.66	44.14	34.41	32.87	42.34	2.50	0.716
Issuer's Weighted Average 2003 Prices	-	41.94	35.52	6.19	28.11	28.11	28.11	38.34		
Forecast										
2004	29.63	37.99	29.69	6.04	38.91	31.15	28.04	40.00	1.50	0.750
2005	26.80	34.24	26.64	5.36	35.07	25.52	22.56	30.45	1.50	0.750
2006	25.76	32.87	25.72	4.80	33.67	23.28	20.58	20.60	1.50	0.750
2007	26.14	33.37	26.27	4.91	34.17	23.63	20.89	15.69	1.50	0.750
2008	26.53	33.87	26.74	4.98	34.69	23.98	21.20	15.92	1.50	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 issuers 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.

TABLE 6

	Oil [1]			Natural Gas Liquids and Sulphur						
Year	WTI CUSHING OKLAHOMA ($US/bbl)	Edmonton Par Price 40 degree API ($Cdn/stb)	Hardisty Bow River $Cdn/stb	Natural Gas[1] AECO Gas Prices ($Cdn/Mcf)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Edmonton Propane FOB Field Gate ($Cdn/bbl)	Plant Gate Sulphur (Mlt)	Inflation Rate[2] (%/Year)	Exchange Rate[3] ($US/$Cdn)
2003 (Year End)	-	38.10	31.79	6.26	29.68	29.68	29.68	52.00	-	-
Issuer's Weighted Average 2003 Prices	-	41.94	35.52	6.19	28.11	28.11	28.11	38.34	-	-
Forecast										
2004	29.63	37.99	29.69	6.04	38.91	31.15	28.04	40.00	1.50	0.750
2005	26.80	34.24	26.64	5.36	35.07	25.52	22.56	30.45	1.50	0.750
2006	25.76	32.87	25.72	4.80	33.67	23.28	20.58	20.60	1.50	0.750
2007	26.14	33.37	26.27	4.91	34.17	23.63	20.89	15.69	1.50	0.750
2008	26.53	33.87	26.74	4.98	34.69	23.98	21.20	15.92	1.50	0.750
Thereafter	Various Escalation Rates									

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Exchange rates used to generate the benchmark reference prices in this table.

TABLE 7

Energy North Revenue Reconciliation

Based on Constant Prices and Costs, Future Values @ 10% Discount

	2003 M$	Notes
Estimated Future Net Revenue Atax at Beginning of Year	20,622	
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	-8,992	
Net Change in Prices, Production Costs and Royalties Related to Future Production	-2,353	
Changes in Previously Estimated Development Costs Incurred During the Period	1,509	
Changes in Estimated Future Development Costs	-813	
Extensions and Improved Recovery	5,823	1,3
Discoveries	4,947	1,3
Acquisitions of Reserves	15	3
Dispositions of Reserves	-1,563	3
Net Change Resulting from Revisions in Quantity Estimates	-9,707	
Accretion of Discount	2,509	
Net Change in Income Taxes for Current Period	3,307	2
Net Change in Income Taxes for Future	4,091	2
Miscellaneous Changes	-277	
Estimated Future Net Revenue Atax at End of Year	19,118	

Notes:
1 New Drills
2 Tax Pools not included in Beginning Year Evaluation
3 Base on Net Reserves after Royalties

TABLE 8

ENERGY NORTH INC.

RECONCILIATION OF WORKING INTEREST RESERVES
1-Jan-04

PROVED	LT.&MED. OIL (MSTB)	HEAVY (MSTB)	NGLs (MSTB)	NON ASSOC.& SOL. GAS (MMCF)	BOEs
RESERVES @ JANUARY 1, 2003	711.8	0.0	271.4	6,947.0	2,141.0
PRODUCTION	-41.0	-69.5	-48.3	-1,505.0	-409.6
ACQUISITIONS	0.0	0.0	0.0	1.0	0.2
DISPOSITIONS	0.0	0.0	-0.4	-666.0	-111.4
DISCOVERIES AND EXTENSIONS	40.1	0.0	38.9	4,104.0	763.0
REVISIONS	-270.8	251.0	-50.1	-2,052.0	-411.9
RECLASSIFICATIONS	-251.0	0.0	0.0	0.0	-251.0
RESERVES @ JANUARY 1, 2004	189.1	181.5	211.5	6,829.0	1,720.3

PROBABLE	LT.&MED. OIL (MSTB)	HEAVY (MSTB)	NGLs (MSTB)	NON ASSOC.& SOL. GAS (MMCF)	BOEs
RESERVES @ JANUARY 1, 2003	78.5	0.0	54.7	2,990.0	631.5
PRODUCTION	0.0	0.0	0.0	0.0	0.0
ACQUISITIONS	0.0	0.0	0.0	1.0	0.2
DISPOSITIONS	0.0	0.0	-0.4	-484.0	-81.1
DISCOVERIES AND EXTENSIONS	5.5	0.0	19.7	2,412.0	427.2
REVISIONS	-23.8	0.0	14.4	-1,008.0	-177.4
RECLASSIFICATIONS	0.0	85.1	0.0	0.0	85.1
RESERVES @ JANUARY 1, 2004	60.2	85.1	88.4	3,911.0	885.5

PROVED PLUS PROBABLE	LT.&MED. OIL (MSTB)	HEAVY (MSTB)	NGLs (MSTB)	NON ASSOC.& SOL. GAS (MMCF)	BOEs
RESERVES @ JANUARY 1, 2003	790.3	0.0	326.1	9,937.0	2,772.6
PRODUCTION	-41.0	-69.5	-48.3	-1,505.0	-409.6
ACQUISITIONS	0.0	0.0	0.0	2.0	0.3
DISPOSITIONS	0.0	0.0	-0.8	-1,150.0	-192.5
DISCOVERIES AND EXTENSIONS	45.6	0.0	58.6	6,516.0	1,190.2
REVISIONS	-294.6	251.0	-35.7	-3,060.0	-589.3
RECLASSIFICATIONS	-251.0	85.1	0.0	0.0	-165.9
RESERVES @ JANUARY 1, 2004	249.3	266.6	299.9	10,740.0	2,605.8

TABLE 9

Future Development Costs

	Escalated Pricing		Constant Pricing	
	Proved (m$)	Proved+ Probable (m$)	Proved (m$)	Proved+ Probable (m$)
2004	936	1,210	936	1,210
2005	0	102	0	100
2006	0	0	0	0
2007	0	51	0	48
2008	0	0	0	0
2009	34	34	31	31
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	36	0	31
Total	970	1,432	968	1,421
Discounted @ 10%	925	1,321	923	1,314

TABLE 10

Energy North Inc.
Summary of 2003 Operations by Quarter

	Average	1st. Qtr.	2nd. Qtr	3rd. Qtr	4th. Qtr.
Volume					
Oil (bopd)	305.60	396.60	299.10	295.40	248.60
Gas (mcf/d)	4,124.00	3,216.50	2,950.20	4,557.70	5,448.70
NGL (bpd)	127.50	114.00	103.90	136.20	135.70
Price					
Oil ($/bbl)	35.98	46.60	27.46	35.18	30.39
Gas ($/mcf)	6.26	7.31	7.05	5.81	5.60
NGL ($/bbl)	28.63	29.57	24.71	29.06	29.84
Royalties					
Oil ($/bbl)	7.67	9.13	8.43	8.29	4.02
Gas ($/mcf)	1.13	1.61	1.30	0.85	1.01
NGL ($/bbl)	3.00	3.87	1.52	1.74	2.92
Operating Expenses					
Oil ($/bbl)	8.33	9.08	7.92	7.35	7.95
Gas ($/mcf)	1.26	1.10	1.61	1.11	1.29
NGL ($/bbl)	6.30	4.77	6.89	6.83	7.50
Netback					
Oil ($/bbl)	21.99	38.93	11.11	19.54	18.82
Gas ($/mcf)	3.87	4.60	4.14	3.85	3.30
NGL ($/bbl)	19.33	20.93	16.30	20.49	19.42

Form 51-101 F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Energy North Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at December 31, 2003. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 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 December 31, 2003 using constant prices and costs; and

   (ii) the related estimated future net revenue (not included in this report).

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 December 31, 2003, 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 Energy North Inc , as of December 31, 2003 prepared January to March 2004	Canada				
Total			Nil	28,405	Nil	28,405

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 Ltd.
Calgary , Alberta

March 15, 2004

"George F. Fukushima"
George F. Fukushima, P.Eng.
Project Manager & Associate

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

"Hari M. Kapil"
Hari M. Kapil, P.Eng.
Senior Vice-President, Engineering

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities ("NI 51-101")*. This form does not apply in British Columbia.

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.(1)

2. The report referred to in item 3 of section 2.1 of *NI 51-101* shall in all material respects be as follows:

Report of Management and Directors on Reserves Data and Other Information

Management of Energy North 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 December 31, 2003 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, 2003 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 has been filed with securities regulatory authorities with this report.

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, on the recommendation of the Reserves Committee, 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 judgements regarding future events, actual results will vary and the variation may be material.

Date: June 30, 2004

"Richard Edgar"
Richard Edgar, President and Chief Executive Officer

" William Patterson"
William Patterson, Vice President Finance and Chief Financial Officer

"Graeme Dales"
Graeme Dales, Director

"Francis Lefaivre"
Francis Lefaivre, Director

1 For the convenience of readers, Appendix 1 to Companion Policy 51-101CP sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in *NI 51-101, Form 51-101F1, Form 51-101F2* or the Companion Policy.