TransGlobe Energy
CORPORATION

2002
Annual Report

Annual Meeting

TransGlobe Energy Corporation will hold its Annual and Extraordinary Meeting on Thursday, May 29, 2003 at 3:00 p.m. The meeting will be held in the McMurray Room at the Calgary Petroleum Club located at 319 - 5th Avenue S.W., Calgary, Alberta, Canada.

Abbreviations

Cdn	Canadian
U.S.	United States
WTI	West Texas Intermediate
Bbl	barrel
Bopd	barrels of oil per day
MBbls	thousand barrels
MMBbls	million barrels
Mcf	thousand cubic feet
Mcfpd	thousand cubic feet per day
MMcf	million cubic feet
MMcfpd	million cubic feet per day
Tcf	trillion cubic feet
Boe	*barrel of oil equivalent
Boepd	*barrel of oil equivalent per day
MBoe	*thousand barrels of oil equivalent
NGL	natural gas liquids
the Company	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
TransGlobe	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
yr	year
PSA	Production Sharing Agreement
MOM	Ministry of Oil and Minerals, Republic of Yemen
YOC	Yemen Oil Company
Q	Quarter

* conversion of natural gas to oil on the basis of 6,000 cubic feet of natural gas being equivalent to one barrel of oil

This annual report may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

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Highlights

HIGHLIGHTS:

Cash flow increased 66% to $9,709,852

Net income increased 77% to $5,426,389

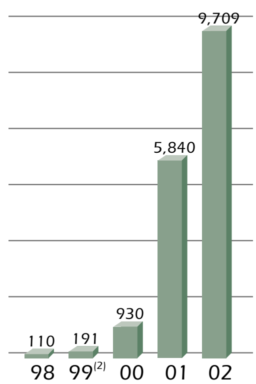
Production increased 27% to 1,732 Boed

Proven reserves increased 33% to 2,347,000 Boe

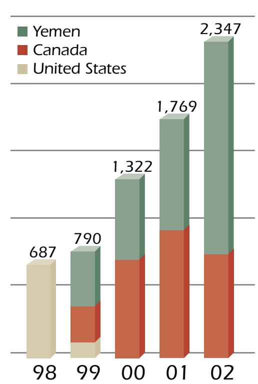
Working capital of $4,748,933 with no debt

Throughout the text of TransGlobe's annual report and consolidated financial statements, all dollar values are expressed in United States dollars unless otherwise stated.

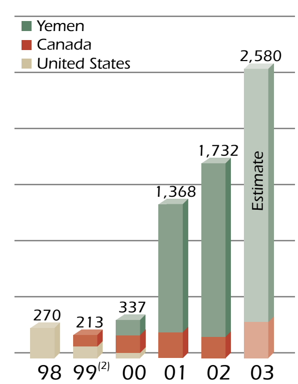
Annual Cash Flow
($000)



Proven Reserves
Thousand Boe's(1)



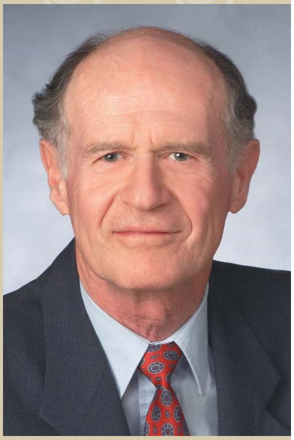
Average Annual Production
Barrels of oil equivalent per day(1)



(1) - 6:1 conversion for Natural Gas
(2) - Results for 1999 are for the 15 month period ended Dec 31, 1999

Message To The Shareholders

Ross G. Clarkson
President, CEO
and Director



Robert A. Halpin
Chairman of the Board
and Director

I am pleased to submit the 2002 Annual Report to the shareholders. Last year the Company achieved record production, cash flow, net income and reserves. In addition to achieving these milestones, the past year has seen a number of noteworthy events that will shape the future growth of the Company. The noteworthy events, the Tasour field extension and the An Nagyah discovery, will provide focus to the Company's efforts in the coming years.

- Tasour #7 - increased reserves leading to increased field production in 2003.

Months of work reprocessing seismic and reviewing analogue fields led to the decision to drill a deviated well targeting a possible extension of the Tasour field. The result was better than anticipated. Tasour #7 increased field reserves by 91 percent. Tasour #8 in January 2003 confirmed the field extension to the west. Another well in the eastern area of the extension (Tasour #9) is currently drilling.

This discovery has two important outcomes. The first outcome is a revision of the predicted production profile. The Tasour field is now anticipated to produce for a longer period of time, and at a higher rate of production. In 2003 the Tasour field is expected to average 16,000 barrels of oil per day (approximately 2,200 to TransGlobe) and will provide 90 percent of TransGlobe's revenues. Tasour provides a stable base of cash flow for the Company that affords an expanded exploration and development program in all operational areas.

The second outcome of this discovery is that it provides a whole new exploration concept along the southern, bounding fault. This may lead to additional Tasour reserves or to the discovery of new pools.

- An Nagyah Discovery - potential to take TransGlobe to a new level.

The An Nagyah discovery of 2002 may provide the foundation, or "anchor", project for commercial development of Block S-1. In December 2002 the Company participated in a new oil discovery in Block S-1 on the An Nagyah (pronounced An Nah - gee - yah) structure. The appraisal drilling on this discovery in early 2003 was very encouraging. Additional drilling and engineering work remains to be done on the An Nagyah structure before committing to a development project. This work is expected to be completed in the first half of 2003.

The An Nagyah discovery follows the 2000 Harmel oil discovery and the An Naeem gas/condensate discovery. A preliminary look at the development plan would envisage initially bringing An Nagyah on stream and then layering in Harmel and An Naeem production in a staged approach. All three discoveries are complementary to the commercial development. Development time to first oil could be similar to the Tasour field, which took eleven months to complete.

Block S-1 is expected to provide the next significant growth in revenues and cash flow. The Company is working towards this having an impact upon the 2004 numbers.

- *Other strategic choices affecting TransGlobe's future.*

During 2002 TransGlobe management reviewed the Company's project portfolio. The aim of the review was to ensure a diversified portfolio of projects which balance risk/reward ratios, cycle time, and oil versus gas. The higher cash flow of 2002 has allowed the Company to consider broadening its project portfolio.

The result is that in 2003 the Company will refocus some capital into Canadian natural gas exploration. Natural gas prices appear to have reached a sustainable higher level. This, along with shorter cycle time and low development costs, make gas a very attractive investment. Land for five drilling locations was recently acquired and additional lands are currently being sought to expand the drilling program. Successful wells could be tied-in in late 2003.

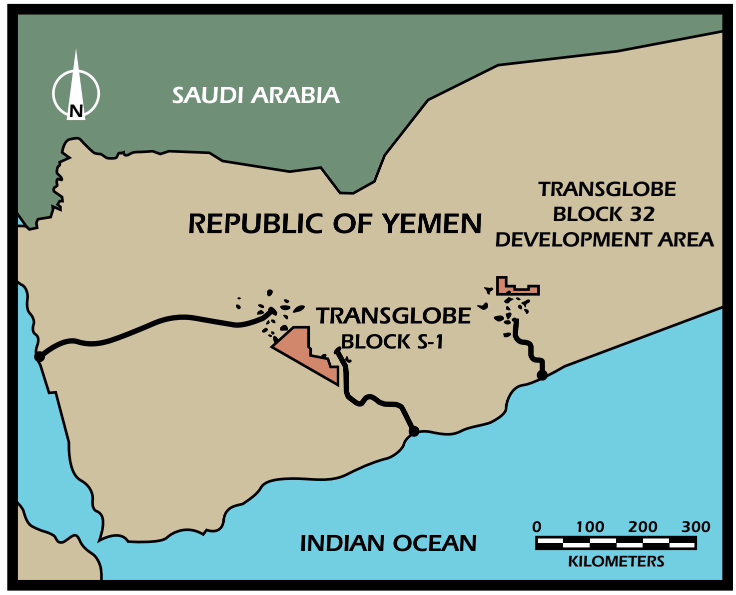
Over the course of the year the Company also reviewed several international new ventures. To enhance and accelerate our capabilities we have directed a portion of our 2003 budget to contract an additional staff member to focus exclusively on new ventures.

In conclusion TransGlobe has completed a record year and enters 2003 debt free, well funded and positioned for additional growth on all its projects. We anticipate 2003 will provide even greater gains for the shareholders.

Ross G. Clarkson — *April 17, 2003*
President, CEO and Director

OPERATING

INTERNATIONAL ACTIVITY



BLOCK 32, REPUBLIC OF YEMEN

- Tasour field extension and new pool discovery
- Record production
- Tasour facilities expanded for increased volumes
- Tasour water injection facilities expanded
- Two wells drilled and one well drilling at year end

Background

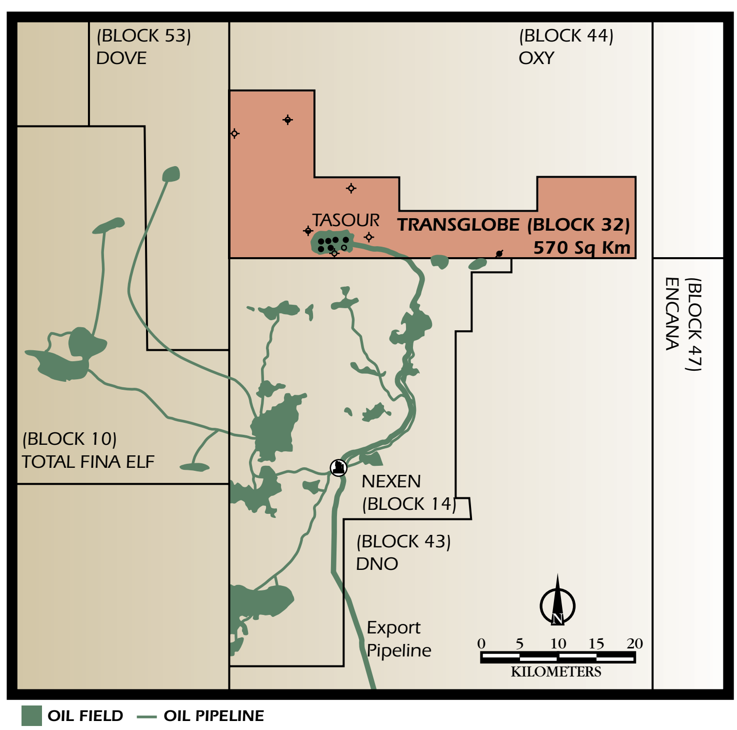
TransGlobe entered into its first international project in January 1997 through a farmout agreement and joint venture on Block 32. The Company has since participated in acquisition of seismic data, drilling of fourteen wells and construction of production facilities, resulting in commencement of Tasour field production on November 3, 2000. The joint venture currently consists of TG Holdings Yemen Inc. (a wholly-owned subsidiary of TransGlobe Energy Corporation) with a 13.81087% working interest and partners Ansan Wikfs Hadramaut Ltd. and DNO ASA holding the balance ("the Block 32 Joint Venture Group"). DNO ASA (an independent Norwegian oil company) is the operator of the Block. The Yemen Oil Company ("YOC" - a Yemen government oil company) has a 5% interest in the Block 32 Joint Venture Group's production sharing oil.

The Block 32 development area covers 570 square kilometers (approximately 228 square miles). The development area encompasses all of the Tasour structure and nine additional prospects. The approved development/production period extends until the year 2020, with an optional five-year extension to 2025.

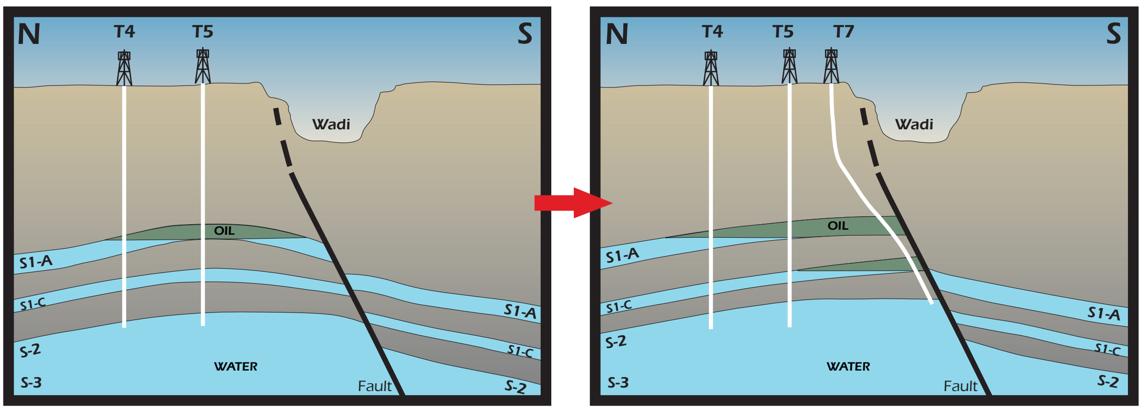
2002 Activities and Results

Exploration

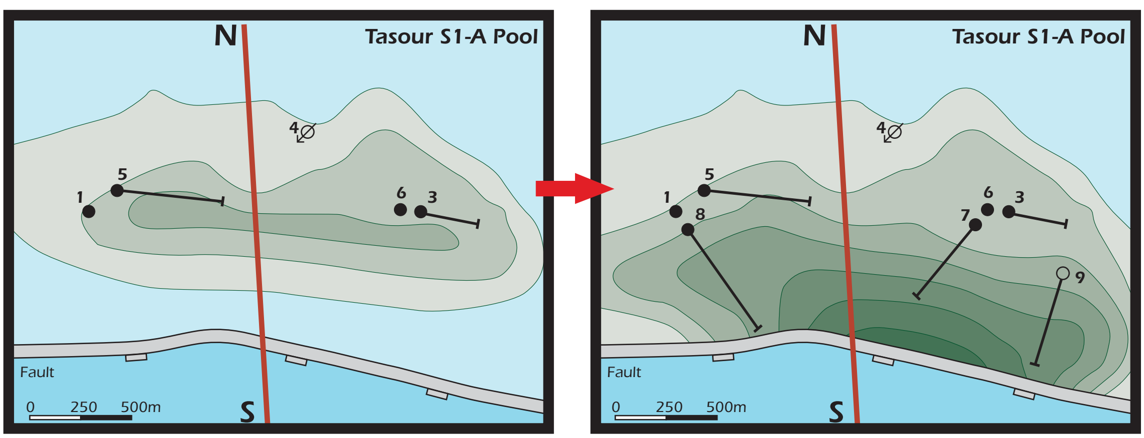
The past year witnessed excellent growth in reserves, production and a reduction in operating costs for the Tasour field. The Block 32 Joint Venture Group drilled three wells in 2002, one of which was drilling over the year end. One well encountered oil and was placed on production (Tasour #7), one well was dry and abandoned and the third well (Tasour #8) was completed as an oil producer early in 2003.



The first well, Asswairy #1, was drilled in early 2002. Although several zones with oil shows were tested, no hydrocarbons were recovered so the well was abandoned. The second well, Tasour #7, was drilled in September to evaluate a potential field extension to the south of the mapped limits of the Tasour field (see figure below). The Tasour #7 well encountered the main producing zone (Qishn S-1A sandstone) in a structurally higher position than the previously mapped crest of the field. The well also encountered a new productive zone in an underlying sand, the Qishn S-1C. As can be seen from the cross section and revised maps, the size of the Tasour field was enlarged considerably and several new development drilling locations in the southern extension were identified. The first of the new development wells was successfully completed at Tasour #8 in January 2003 at an initial rate of 9,000 Bopd. A second development well targeting the southern field extension commenced drilling at Tasour #9 in April 2003.



Pre Tasour 7 Interpretation **Post Tasour 7 Interpretation**



The extension of the Tasour field to the southern, bounding fault has increased the size of the field to over 20 million barrels. When commerciality was declared in 2000 the field proven plus probable reserves were estimated at only 6.9 million barrels. This represents a 300% increase in the estimated size of the Tasour field. The Tasour field had produced 7.5 million barrels by December 31, 2002. The remaining proven plus probable reserves are now estimated at 13.3 million barrels (1.836 million barrels to TransGlobe).

The Tasour #7 and #8 wells have changed the structural mapping of the Tasour field. The revised structural picture of the field has set up a number of potential exploration prospects to the west and the east of the Tasour field along the main bounding fault. Additional seismic reprocessing and remapping work is underway to select new exploration drilling locations. It is anticipated the first of these locations will be drilled in Q-2, 2003 as a potential extension of the Tasour field to the west (probably named Tasour #10).

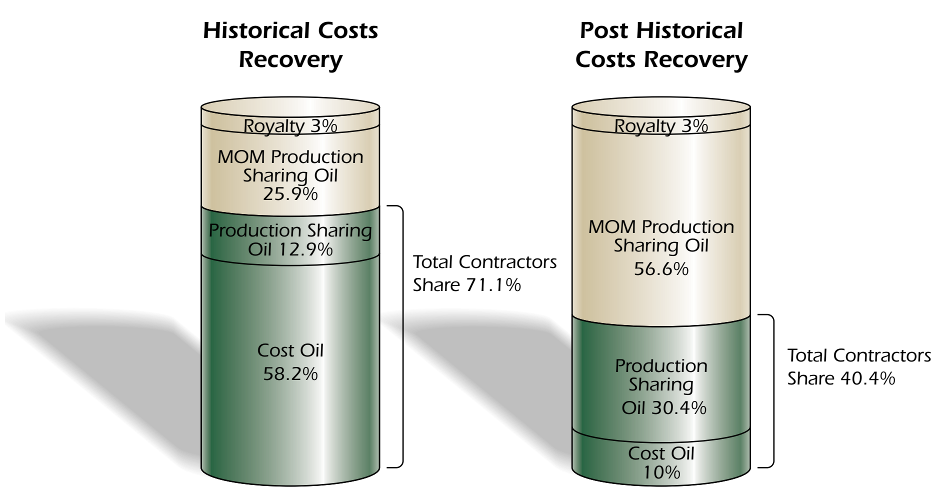
In addition to the exciting new potential along the main Tasour south bounding fault trend, the Block 32 Joint Venture Group shot a 120 kilometer 2-D seismic program to further delineate prospects on the eastern portion of the block. The data was processed in Q-1 2003 and is being interpreted. It is expected that some of these prospects will be ready to drill in the future. The eastern prospects will not be drilled until at least 2004, depending upon the results in and around the Tasour field.

Production

In Block 32, TransGlobe's working interest production increased 37% from an average of 1,131 Bopd in 2001 to an average of 1,545 Bopd in 2002, with an exit rate of 1,996 Bopd for the month of December 2002. Production increases in 2002 are primarily attributed to the field extension and to the new pool discovery drilled at Tasour #7 in September 2002.

With the completion of Tasour #8 in January 2003 the production potential of the six wells exceeded the facility capacity. Tasour field production was restricted to 16,000 Bopd (2,210 Bopd to TransGlobe) during January and February 2003 due to limited export pump capacity. In March production averaged 17,870 Bopd (2,468 Bopd to TransGlobe) as shut in wells were returned to production and two wells were worked over to replace submersible pumps. The Tasour central production facility ("CPF") was initially designed to process 15,000 Bopd with expansion capability to match the sales pipeline capacity of 25,000 Bopd. The facility was expanded in early 2002 to handle additional water and oil production. A second facility expansion to increase export pumping capacity to greater than 20,000 Bopd was completed in late February 2003. In addition to the CPF expansion, a water disposal/injection scheme was initiated in 2002, with the majority of the water being injected into Tasour #4. The produced oil and water is separated at the Tasour CPF and the sales oil is pumped to the Nexen Inc. CPF where it enters the Nexen Inc. export pipeline. The oil is pumped to the tanker loading facilities at Riyan on the Indian Ocean for export and sale.

The Block 32 PSA allows for the recovery of historical costs out of production. With the significantly increased oil production and higher oil prices in late 2002 and early 2003 it is expected that all of the historical costs will be recovered early in the second quarter of 2003. A diagram of the production sharing splits before and after full cost recovery is shown on the figure below. In general terms the Block 32 Joint Venture Group's ("Contractors") share of oil will reduce from 71.1% to an estimated 40% to 50% of production, depending upon gross revenue, operating costs and future eligible capital expenditures. All qualifying new capital expenditures, such as new seismic or new wells within the Block 32 development area, can be recovered out of cost oil. Therefore the cost oil portion of production can increase or decrease depending on future expenditures.



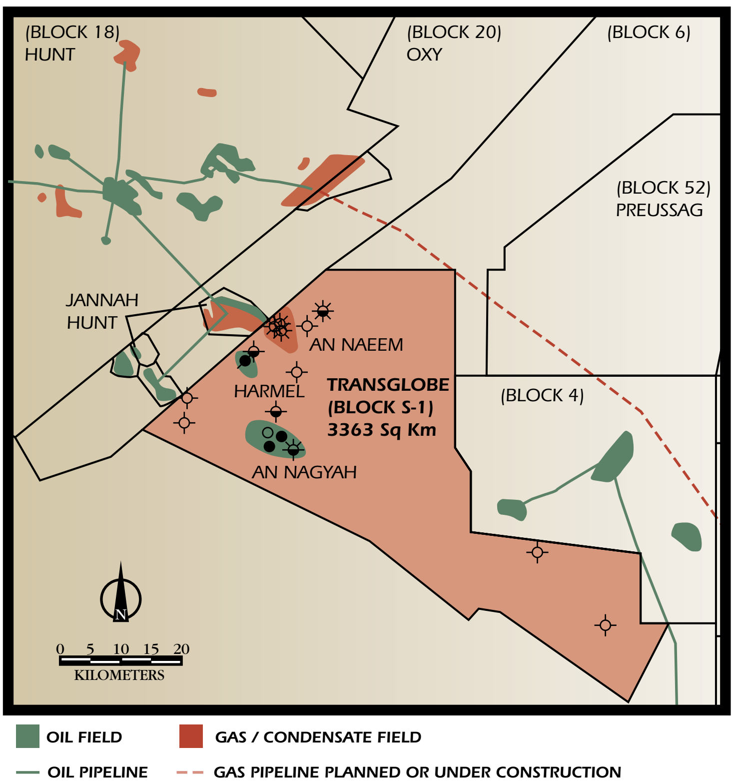
Block 32 Production Sharing - 0 to 25,000 Bopd

2003 Outlook

The 2003 Block 32 Joint Venture budget and work program includes drilling two development/appraisal wells, two exploration wells and one contingency well. To date, two wells have been drilled resulting in a producing oil well at Tasour #8 and an exploratory dry hole at Haibish. The development/appraisal well at Tasour #9 commenced drilling in April 2003. It is expected that an exploratory well to the west of the Tasour field will be drilled in the June 2003 (Tasour #10). Another contingent well could be drilled in the fourth quarter of 2003.

BLOCK S-1, REPUBLIC OF YEMEN

- New oil discoveries at An Nagyah #2 (Dec. 2002) and An Nagyah #3 (Feb. 2003)
- Gas/Condensate found at An Naeem #3
- Appraisal drilling planned at An Nagyah #4
- Entered Second Exploration Period (Mar. 2002)



Background

TransGlobe entered into its second international exploration venture in 1997 by signing a Production Sharing Agreement ("PSA") for the Damis S-1 Block ("Block S-1") with the Ministry of Oil and Minerals ("MOM").The PSA was ratified by the Yemen Parliament on June 14, 1998 and was signed by the President of the Republic of Yemen on June 28, 1998. TG Holdings Yemen Inc. (a wholly owned subsidiary of TransGlobe Energy Corporation) entered into a joint venture arrangement for Block S-1 with a subsidiary of Vintage Petroleum Inc., a U.S. independent exploration and production company based in Tulsa, Oklahoma ("Block S-1 Joint Venture Group"). During 2000 Vintage earned a 75% working interest in Block S-1 by funding 100% of the work commitments for the first exploration period of the Block S-1 PSA and by spending a minimum of $20 million. TransGlobe has retained a 25% working interest in Block S-1. The YOC has a 17.5% interest in the Block S-1 Joint Venture Group's share of production sharing oil.

Block S-1 is strategically located near existing pipelines and adjacent to the Yemen Hunt Oil Co.'s Marib al Jawf production area. Close proximity to pipelines and Yemen Hunt Oil Co.'s infrastructure will significantly reduce the cost of developing an oil discovery on Block S-1 and will shorten the time period required to commence oil production. The Marib al Jawf basin is a prolific producing region with discovered fields of over 900 MMBbls of oil and 7 Tcf of gas with current production of 140,000 Bopd.

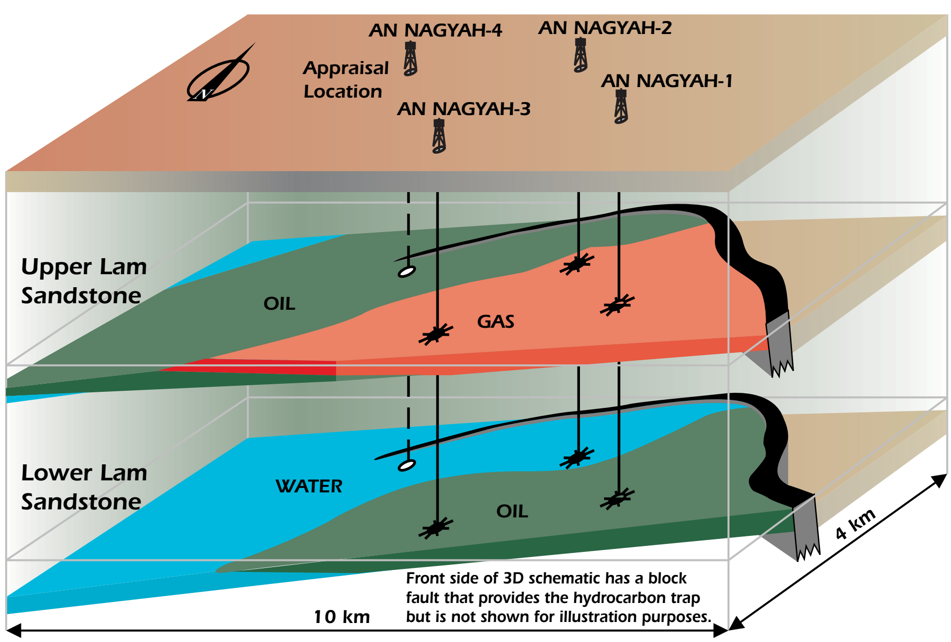
The first exploration period ended on March 28, 2002 and the Block S-1 Joint Venture Group elected to proceed with a second exploration period of 2 1/2 years. The second exploration period will expire on September 28, 2004 with an optional six month extension to March 28, 2005. The second exploration period commitments were satisfied by the drilling of An Naeem #2 (2000), Osaylan #1 (2002), An Nagyah #2 (2002) and a 3-D seismic survey (2001).

Block S-1 originally encompassed an area of 4,484 square kilometers (approximately 1,794 square miles). Upon entering the second exploration period a mandatory 25% relinquishment reduced the area to 3,363 square kilometers (approximately 1,345 square miles). The relinquished lands were not considered prospective.

2002 Activities and Results

Exploration

The 3-D seismic acquired in 2001 was interpreted during the first half of 2002 and drilling locations were selected. In September 2002 the Block S-1 Joint Venture Group initiated the second drilling campaign on the block. Two wells were drilled and tested and one well was still drilling at the end of 2002. The first well, Osaylan #1, was drilled to a total depth of 1,902 meters and was abandoned after encountering minor oil shows. The primary target, the Alif reservoir sandstone, was encountered however the logs did not indicate hydrocarbons were present. The second exploration well, An Nagyah #2, was drilled to a total depth of 1,624 meters and discovered light 46 degree oil in the Upper Lam formation. The well was suspended as a potential future oil producer after testing up to 1,100 Bopd from the Upper Lam formation. The third exploration well, An Naeem #3, was drilled to a total depth of 1,623 meters to evaluate a potential oil rim on the An Naeem structure. The An Naeem #3 well tested gas and condensate from the Alif zone and did not encounter the anticipated oil rim. The fourth well of the program, An Nagyah #3, commenced drilling in February 2003 to appraise the light oil discovery made at An Nagyah #2. The well was drilled to a total depth of 1,292 meters and encountered the Upper Lam sandstones in a structurally higher position than the An Nagyah #2 well. Although the Upper Lam sandstones had a thicker gross reservoir section and better indicated porosity and permeability than found at An Nagyah #2, the Upper Lam was not flow tested as it was entirely above the gas/oil contact found in the An Nagyah #2 well. The An Nagyah #3 well did test 240 Bopd of light 42 degree oil from a new pool in the Lower Lam. The core and test data indicate the Lower Lam reservoir has less porosity and permeability than the Upper Lam reservoir and therefore may require stimulation to enhance production. The discovery of a new productive horizon in the Lower Lam should augment development economics. The fifth well in the program, An Nagyah #4, is scheduled to commence drilling in late April to appraise the Upper Lam oil pool discovered in An Nagyah #2 in a structurally down dip position. The diagram below indicates the relative positions of the An Nagyah wells and the northward dipping Upper and Lower Lam zones.



The An Nagyah structural closure mapped on 3-D seismic data could encompass up to 18 square kilometers (7 square miles). A successful appraisal well at An Nagyah #4 could lead to a fast track development of the discovery or to additional appraisal drilling and testing prior to committing to a development scheme.

Potential Development Scheme

Management of the Company is optimistic that the An Nagyah light oil discovery could provide the Company with its first oil production from Block S-1 as early as the second half of 2004. This is contingent upon the results of future appraisal drilling, particularly at An Nagyah #4.

The development plan envisions an integrated, phased project which includes the light oil discovered at An Nagyah, the natural gas/condensate discovery at An Naeem and the shallow medium gravity oil discovery at Harmel #1. The An Nagyah discovery could initially produce 6,000 to 10,000 Bopd (1,500 to 2,500 Bopd to TransGlobe) exported through the Hunt Oil Co. operated pipeline system to the tanker loading facility on the Red Sea. The nearest potential tie in point to the export pipeline system is approximately 28 kilometers (18 miles) from An Nagyah.

Natural gas and condensate from the An Naeem discovery would be pipelined to An Nagyah. Gas would be separated for injection into the Upper Lam formation to maintain reservoir pressure and increase oil recovery. Stabilized condensate from An Naeem would be sold with the An Nagyah light oil production and used to blend with the medium gravity oil discovered at Harmel. With An Nagyah as the anchor project, the Harmel #1 shallow oil well could be placed on early production. Initially the Harmel oil would be trucked to the An Nagyah facility for blending with An Naeem condensate and sold with the An Nagyah production.

Additional Harmel shallow oil wells could be drilled and placed on production until sufficient reservoir information is obtained to properly evaluate the merits of a full scale commercial development of the Harmel shallow oil discovery. The Harmel #1 well tested medium gravity crude from three shallow horizons at a depth of approximately 400 to 700 meters. The horizons were mapped on good quality 3-D seismic and display a structural closure of up to 25 square kilometers (10 square miles). Should full commercial development proceed, forty to eighty additional shallow wells could be required to exploit the large structure.

Concurrent with the appraisal and evaluation of a potential light oil development scheme at An Nagyah, we are studying the feasibility of developing the large gas reserves found in the An Naeem #1, #2 and #3 wells. The gas could be utilized in Yemen for electricity generation or exported to nearby markets utilizing CNG ("Compressed Natural Gas") technology. Both possibilities are under investigation. A gas development project of this magnitude will require significantly more time to evaluate, design and construct than conventional oil production. However it could be a significant addition to the Company's longer-term asset portfolio.

2003 Outlook

The primary focus for 2003 will be the appraisal and testing of the An Nagyah light oil discovery which could lead to the declaration of a commercial oil project prior to year end. The Lam reservoir encountered at An Nagyah is a new producing horizon in Yemen. Its discovery opens up a new exploration focus for Block S-1. In addition to the An Nagyah appraisal work, the current drilling program results are being integrated into the Company's extensive seismic database to define future exploration drilling prospects.

CANADA

- New production at Cherhill and Nevis
- Dramatically improved natural gas prices (Q-4 2002)
- Divestiture of minor properties
- Expanded 2003 capital budget

Background

TransGlobe acquired its Canadian operations in April 1999. The majority of the Canadian operations are operated by TransGlobe and are focused almost exclusively in the southern/central part of the province of Alberta. The Canadian operations have been successfully expanded to provide increased cash flow and asset value. Although Canadian production is now dwarfed by our international production, the Canadian operations will continue to be expanded to capitalize on the North American gas market. In addition to developing and exploiting our producing areas, the Company has acquired land and has generated a number of drillable prospects within its core focus areas.

2002 Activities and Results

Drilling activity in Canada was curtailed during 2002 due to allocation of resources to the projects in Yemen and due to depressed natural gas prices in North America during the first three quarters of 2002. The Company drilled three wells in 2002 resulting in two producers at Nevis and one shut-in gas well at Morningside.

At Cherhill, the Company completed and tied in a 100% working interest gas well drilled in late 2001. The well commenced production in February 2002 and is currently producing 55 to 60 Boepd.

At Morningside, the Company drilled and completed a marginal shallow gas well (58% working interest) which may be pipeline-connected in the future. Also at Morningside, the Company plans to install a three mile pipeline to connect a 100% working interest gas well which should initially produce 100+ Boepd. It is expected to be connected by the fall of 2003, pending the successful resolution of ongoing landowner negotiations which have delayed the project to date.

At Nevis, the Company drilled two wells in the latter half of 2002 which were placed on production in early 2003. Additional acreage was acquired in the area in late 2002 and early 2003. The Company plans to acquire additional acreage in the area and to drill a minimum of two wells with contingency for another six to eight wells, all focused on natural gas.

The Company sold minor non-core producing properties at Provost, Alberta and Wildmint, British Columbia in 2002.

2003 Outlook

With record cash flow from Yemen in 2002 and early 2003, the Company expanded the Canadian budget to focus on natural gas projects. To date, the Company acquired mineral rights on 7,200 net acres in 2003 and farmed-in on an additional 4,480 (2,240 net) acres. The Company plans to acquire additional mineral rights and is negotiating several farm in proposals. The majority of the land is located in Central Alberta on three main prospects, of which two are new focus areas for the Company.

It is anticipated that the Company will drill a minimum of four to six wells, with contingency for an additional six to eight wells. All the prospects are focused towards natural gas. It is expected that drilling will commence in June. Successful wells could be on production by late 2003 as all the prospects are near to existing infrastructure and can be accessed year round.

PRODUCTION

The following table is a summary of working interest production, before royalty, by country for the years ended 2002 and 2001.

	2002			2001		
	Oil & Liquids MBbls	**Gas MMcf**	**Total Boe MBoe**	Oil & Liquids MBbls	Gas MMcf	Total Boe MBoe
Canada	**13.6**	**325.7**	**67.9**	19.3	404.0	86.6
Yemen	**564.1**	**-**	**564.1**	412.7	-	412.7
Total	**577.7**	**325.7**	**632.0**	432.0	404.0	499.3

RESERVES AND ESTIMATED FUTURE NET REVENUES

Outtrim Szabo Associates Ltd. of Calgary, Alberta, independent petroleum engineering consultants, evaluated the Company's Canadian reserves at December 31, 2002 and 2001. In Canada, proven reserves declined 18% from 946 MBoe at year end 2001 to 772 MBoe at year end 2002. The decline is primarily due to production, well performance and the divestiture of minor properties during 2002.

Fekete Associates Inc. of Calgary, Alberta, independent petroleum engineering consultants, evaluated the Company's Block 32 reserves in the Republic of Yemen at December 31, 2002 and 2001. TransGlobe's proven reserves in the Tasour field (13.81087% working interest) in Yemen are up 91% from 823 MBbls at year end 2001 to 1,575 MBbls at year end 2002. The increase replaced 233% of 2002 production. The increase in Yemen reserves is attributable to the excellent field performance and to the Tasour #7 field extension and new pool discovery on Block 32. Although a light oil discovery at An Nagyah #2 on Block S-1 was announced December 10, 2002, a medium gravity oil pool was found at Harmel #1 and a gas-condensate pool at An Naeem #1, #2 and #3, proven reserves will not be assigned to Block S-1 until additional appraisal drilling and project evaluation are completed.

Reserves

	Reserves, Working Interest Before Royalties					
	Dec. 31, 2002			Dec. 31, 2001		
	Oil & Liquids MBbls	**Gas MMcf**	**Total Boe MBoe**	Oil & Liquids MBbls	Gas MMcf	Total Boe MBoe
Proven						
Canada	**183.0**	**3,536**	**772.3**	143.8	4,814	946.1
Yemen*	**1,574.9**	**-**	**1,574.9**	823.4	-	823.4
Total proven	**1,757.9**	**3,536**	**2,347.2**	967.2	4,814	1,769.5
Proven plus probable						
Canada	**216.6**	**6,450**	**1,291.6**	187.0	7,290	1,402.0
Yemen*	**1,835.7**	**-**	**1,835.7**	967.0	-	967.0
Total proven plus probable	**2,052.3**	**6,450**	**3,127.3**	1,154.0	7,290	2,369.0
Total proven plus 1/2 probable	**1,905.1**	**4,993**	**2,737.3**	1,060.6	6,052	2,069.3

* Yemen reserves presented are for the Block 32 Tasour field only.

Estimated Future Net Revenues

The estimated future net revenues presented below are calculated using the average price received during the final month of the respective reporting periods. The prices were held constant for the life of the reserves.

	Present Value of Future Net Revenues, Before Income Tax**							
	Constant Pricing							
	Dec. 31, 2002 Discounted at				Dec. 31, 2001 Discounted at			
	Undis-counted ($000)	**10% ($000)**	**15% ($000)**	**20% ($000)**	Undis-counted ($000)	10% ($000)	15% ($000)	20% ($000)
Proven								
Canada *	**12,214**	**8,761**	**7,702**	**6,884**	10,347	6,943	5,961	5,225
Yemen **	**13,309**	**11,904**	**11,322**	**10,802**	6,518	5,830	5,546	5,294
Total proven	**25,523**	**20,665**	**19,024**	**17,686**	16,865	12,773	11,507	10,519
Proven plus probable								
Canada *	**20,054**	**12,792**	**10,888**	**9,499**	14,770	9,284	7,848	6,802
Yemen **	**15,405**	**13,590**	**12,852**	**12,199**	8,720	7,539	7,072	6,665
Total proven plus probable	**35,459**	**26,382**	**23,740**	**21,698**	23,490	16,823	14,920	13,467
Total proven plus 1/2 probable	**30,491**	**23,524**	**21,382**	**19,692**	20,177	14,798	13,214	11,993

* Canadian values converted at the December 31, 2002 and December 31,2001 exchange rates of 1.5776 and 1.5928 $US/$Cdn respectively.

** Yemen future net revenues presented are for the Block 32 Tasour field only and include Yemen income tax.

The estimated future net revenues presented below are calculated using escalated pricing forecasts of the respective engineering consulting firms.

Present Value of Future Net Revenues, Before Income Tax**

	Escalated Pricing							
	Dec. 31, 2002				Dec. 31, 2001			
	Discounted at				Discounted at			
	Undis- counted ($000)	**10% ($000)**	**15% ($000)**	**20% ($000)**	Undis- counted ($000)	10% ($000)	15% ($000)	20% ($000)
Proven								
Canada *	**7,922**	**5,817**	**5,162**	**4,651**	11,124	7,336	6,268	5,476
Yemen **	**9,122**	**8,231**	**7,855**	**7,519**	6,358	5,683	5,405	5,158
Total proven	**17,044**	**14,048**	**13,017**	**12,170**	17,482	13,019	11,673	10,634
Proven plus Probable								
Canada *	**12,602**	**8,282**	**7,126**	**6,273**	16,256	9,905	8,317	7,177
Yemen **	**10,409**	**9,295**	**8,833**	**8,421**	8,570	7,398	6,934	6,531
Total proven plus probable	**23,011**	**17,577**	**15,959**	**14,694**	24,826	17,303	15,251	13,708
Total proven plus 1/2 probable	**20,028**	**15,812**	**14,488**	**13,432**	21,154	15,161	13,462	12,171

* Canadian values converted at the December 31, 2002 and December 31,2001 exchange rates of 1.5776 and 1.5928 $US/$Cdn respectively.

** Yemen future net revenues presented are for the Block 32 Tasour field only and include Yemen income tax.

The following table summarizes the constant pricing used to estimate future net revenues.

	December 2002		December 2001	
	Oil US$/Bbl	**Natural Gas US$/Mcf**	Oil US$/Bbl	Natural Gas US$/Mcf
Canada *	**25.23**	**4.24**	17.07	2.83
Yemen	**30.28**	**-**	18.62	-

* Canadian values converted at the December 31, 2002 and December 31,2001 exchange rates of 1.5776 and 1.5928 $US/$Cdn respectively.

The following table summarizes the escalated pricing used to estimate future net revenues.

	Yemen (Fekete Pricing)		North America (Outtrim Pricing)			
	Masila Blend US$/Bbl		WTI Oil Ref. US$/Bbl		Gas-AECO Spot US$/Mcf	
Year	**2002**	2001	**2002**	2001	**2002***	2001*
2002	**N/A**	18.25	**N/A**	20.50	**N/A**	2.58
2003	**23.27**	18.25	**26.00**	20.81	**3.58**	2.75
2004	**21.02**	18.75	**23.35**	21.12	**3.21**	2.78
2005	**20.27**	19.25	**21.63**	21.44	**2.93**	2.78
2006	**20.52**	19.75	**21.96**	21.76	**2.95**	2.80
2007	**20.97**	20.20	**22.29**	22.08	**2.97**	2.85
Escalated	**2%/yr**	2%/yr	**1.5%/yr**	1.5%/yr	**1.2% to 14 Then 1.5%**	1.2% to 13 then 1.5%

* Canadian values converted at the December 31, 2002 and December 31, 2001 exchange rates of 1.5776 and 1.5928 $US/$Cdn respectively.

FINANCIAL

Management's Discussion and Analysis

The following discussion and analysis is management's opinion of TransGlobe's historical financial and operating results and should be read in conjunction with the message to the shareholders, the operations review, the audited consolidated financial statements of the Company for the years ended December 31, 2002 and 2001, together with the notes related thereto. ***All dollar values are expressed in U.S. dollars, unless otherwise stated.***

RESULTS OF OPERATIONS

Net income for 2002 was $5,426,389 ($0.11 per share basic and $0.10 per share diluted) compared to a net income of $3,062,237 ($0.06 per share, basic and diluted) in 2001. Cash flow from operations for 2002 was $9,709,852 ($0.19 per share, basic and diluted) compared to $5,840,455 ($0.12 per share basic and $0.11 per share diluted) in 2001. The increase in net income and cash flow in 2002 is primarily a result of increased production (27%), increased commodity prices and from cost oil reallocation with partners in the Republic of Yemen.

OPERATING RESULTS

	Consolidated			
	2002		2001	
	$	**$/Boe**	$	$/Boe
Oil and gas sales	**15,386,359**	**24.34**	11,045,880	22.11
Royalties	**2,132,254**	**3.37**	2,491,795	4.99
Operating expenses	**1,843,273**	**2.92**	1,540,369	3.08
Net operating income*	**11,410,832**	**18.05**	7,013,716	14.04

* Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in the Republic of Yemen (2002 - $986,862, $1.56/Boe; 2001 - $634,716, $1.27/Boe).

In 2002 the Company operated in two geographic areas, segmented as the Republic of Yemen and Canada. Management's discussion and analysis will follow under each of these segments.

Republic of Yemen

	2002		2001	
	$	**$/Boe**	$	$/Boe
Oil sales	**14,206,217**	**25.18**	9,137,800	22.14
Royalties	**1,967,506**	**3.49**	2,137,124	5.18
Operating expenses	**1,394,379**	**2.47**	1,133,092	2.74
Net operating income*	**10,844,332**	**19.22**	5,867,584	14.22

* Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in the Republic of Yemen ($2002 - $986,862, $1.75/Boe; 2001 $634,716, $1.54/Boe).

TransGlobe commenced production on Block 32 on November 3, 2000. Production from the block is shared between the Block 32 Joint Venture Group and MOM pursuant to a PSA. The PSA provides for MOM to receive a 3% royalty of gross production (10% over 25,000 Bopd) with the remaining 97% of revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of the revenue after deducting royalty. Cost recovery oil allows the Block 32 Joint Venture Group to recover operating costs and exploration and development expenditures as outlined in the PSA. The remaining oil is allocated to production sharing oil shared 65% by MOM and 33.25% by the Block 32 Joint Venture Group and 1.75% to YOC. The net result of the entire production sharing agreement is that 71.1% of the oil is allocated to the Block 32 Joint Venture Group during recovery of historical costs. The Block 32 Joint Venture Group's Yemen income taxes are paid out of the MOM's share of production sharing oil. These terms remain in place until gross proven recoverable reserves exceed 30 million barrels of oil or until gross production exceeds 25,000 Bopd.

With significantly increased production, higher oil prices and a 91% increase in proven reserves, management expects to have recovered all the historical costs early in the second quarter of 2003. Following the recovery of the historical exploration and development costs, any new expenditures are recovered out of cost oil from production. Operating expenses are recovered out of cost oil immediately and future eligible expenditures within the Block (such as new wells or facilities) can be recovered out of future production within two years of the expenditures. The Block 32 Joint Venture Group's share of production following the recovery of historical costs will vary from year to year, depending upon gross revenues, operating costs and eligible capital expenditures within the PSA area. After recovery of historical costs management anticipates that the revenues from the Tasour field that could be allocated to cost recovery will exceed any new expenditures. This will result in a lower cost oil allocation and a larger production sharing oil allocation. The net result is expected to be a reduction of the Block 32 Joint Venture Group's total share of oil from 71.1% to an estimated 40% to 50% of production, depending upon gross revenue, operating costs and eligible capital expenditures (see diagram on Page 8).

Oil production was 1,545 Bopd to TransGlobe in 2002 compared to 1,131 Bopd in 2001 with an average selling price of $25.18 per barrel (2001 - $22.14 per barrel). Oil exported for sale (Masila blend) is marketed by Nexen Marketing International Ltd. and the price is based on an average dated Brent price less a quality/transportation differential between the dated Brent and the Masila blend. This differential averaged $0.47 per barrel in 2002 and $1.49 per barrel in 2001. TransGlobe expects 2003 gross production from the Tasour field to average 16,000 Bopd (2,210 Bopd to TransGlobe), not including production from future drilling success.

A decrease in royalty expense to $1,967,506 in 2002 compared to $2,137,124 in 2001 is a direct result of reallocations made between the Block 32 Joint Venture Group partners for historical cost pool recoveries during 2002. TransGlobe received a total reallocation of $1,349,077 in 2002 from the Block 32 Joint Venture Group. The majority of the 2002 historical cost pool reallocation represents the recovery of TransGlobe's original farm-in costs on Block 32 in 1997. It is anticipated that the balance of the historical cost pools dating back to 1992 will be recovered in early 2003, which will result in a final historical cost pool reallocation between the Block 32 Joint Venture Group partners. When the remaining historical costs are recovered in 2003, TransGlobe will have a lower interest in the old historical cost pools (8.88302% versus 13.81087%) and therefore TransGlobe will have a cost sharing reallocation of approximately $1,245,000 to the other partners in the Block 32 Joint Venture Group. Thereafter all future expenditures paid out of cost oil will be allocated at TransGlobe's working interest (13.81087%).

The royalty expense is comprised of the MOM's 3% royalty, a portion of MOM's share of production sharing oil representing a royalty, the YOC's share of production sharing oil and a 2% royalty to the agent of the Block 32 Joint Venture Group (less operating cost deductions). Royalties averaged $3.49 per barrel for 2002 compared to $5.18 per barrel in 2001. Royalties before historical cost pool reallocation would have averaged $5.88 per barrel for 2002 with the increase over 2001 attributable to increased oil prices.

Operating costs of $1,394,379 averaged $2.47 per barrel in 2002 compared to $2.74 per barrel in 2001. The decreased cost per barrel is attributed to the allocation of fixed operating costs over increased production volumes. The Transportation and Facilities Usage Contract with Nexen Inc. and the MOM allows for an increase in the export pipeline and loading terminal tariff following recovery of historical costs. Currently the tariff is approximately $0.70 per barrel and it is expected to increase to approximately $1.10 per barrel following historical cost recovery in the second quarter of 2003.

Canada

	2002		2001	
	$	**$/Boe**	$	$/Boe
Oil sales	**210,827**	**22.01**	246,310	21.61
Gas sales (6 : 1)	**901,138**	**16.60**	1,487,615	22.07
NGL sales	**68,177**	**16.84**	174,155	21.51
	1,180,142	**17.38**	1,908,080	21.96
Royalties	**164,748**	**2.43**	354,671	4.08
Operating expense	**448,894**	**6.61**	407,277	4.69
Net operating income	**566,500**	**8.34**	1,146,132	13.19

A 19% decrease in gas volumes and a 25% decrease in average natural gas prices in 2002 resulted in a 39% decrease in gas sales. Gas production averaged 892 Mcfpd in 2002 compared to 1,108 Mcfpd for 2001. The decrease in production is primarily attributed to natural production declines, divestiture of minor properties and to shut-in production during the year in response to low gas prices in the summer. The average natural gas price for 2002 was $2.77 per Mcf compared to $3.68 per Mcf for 2001. To ensure continuous gas production during the traditionally weaker summer market, the Company has entered into a fixed price natural gas sales contract for 500 GJ/day (approximately 500 Mcfpd, or less than 50% of current production) at a price of Cdn$7.65/GJ for the period March 1, 2003 to November 1, 2003.

Oil production averaged 26 Bopd in the year 2002 compared to 31 Bopd in 2001. The decrease is a result of natural production declines and divestiture of minor properties. The average oil price in 2002 was $22.01 per barrel compared to $21.61 per barrel in 2001.

Natural gas liquids production averaged 11 barrels per day in 2002 compared to 22 barrels per day in 2001. Natural gas liquid prices averaged $16.84 per barrel in 2002 and $21.51 per barrel in 2001.

Royalty expenses averaged $2.43 per Boe in 2002 compared to $4.08 per Boe in 2001 which is a reflection of lower prices and gas cost allowance adjustments.

The Company's operating costs of $448,894 during 2002 averaging $6.61 per Boe compared to $4.69 per Boe in 2001 is the result of increased water handling and allocating fixed operating costs over lower production volumes.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses ("G&A") increased 44% to $820,691 from $570,609 in 2001, mainly due to an increase in salary and consulting costs, office rent, insurance and professional services. Management expects G&A to stabilize at this level for 2003.

	2002		2001	
	$	**$/Boe**	$	$/Boe
Gross G&A	**1,213,094**	**1.92**	985,902	1.97
Capitalized G&A	**(392,403)**	**(0.62)**	(415,293)	(0.83)
Net G&A	**820,691**	**1.30**	570,609	1.14

DEPLETION AND DEPRECIATION EXPENSE

Depletion and depreciation was $4,277,000 in 2002 compared to $2,762,000 in 2001. The increase is attributable to the inclusion of additional costs in the depletable base in the Republic of Yemen. In Yemen unproven properties in the amount of $7,184,372 were excluded from costs subject to depletion and depreciation. This represents a portion of the costs incurred in Block S-1. These costs will be included in the depletable base as Block S-1 is developed or as impairment is determined.

	2002		2001	
	$	**$/Boe**	$	$/Boe
Republic of Yemen	**3,960,000**	**7.02**	2,405,000	5.83
Canada	**317,000**	**4.67**	357,000	4.11
	4,277,000	**6.77**	2,762,000	5.53

INCOME TAXES

Current income tax expense represents income taxes paid in the Republic of Yemen which increased to $986,862 during 2002 from $634,716 in 2001 as a result of increased production and revenues in Yemen. Future income tax recovery of $67,168 is a result of offsetting unrecorded future tax benefits in Canada against the future tax effect of tax renunciations to flow through shareholders.

The Company has non-capital losses and tax pools for carry forward against future taxable income in Canada in the amount of Cdn$18,674,000 and tax losses in the United States of $13,100,000.

The Company will not record the future tax benefit of these tax losses and pools in the consolidated financial statements until additional producing reserves are added in Canada.

CAPITAL EXPENDITURES/DISPOSITIONS

Capital Expenditures

	2002	2001
Republic of Yemen	**$ 5,435,398**	$ 3,406,363
Canada	**1,041,146**	1,375,888
	$ 6,476,544	$ 4,782,251

Capital expenditures in the year 2002 in the Republic of Yemen were split mainly between Block 32 and Block S-1. On Block 32 expenditures of $2,022,323 were incurred on a three well drilling program comprised of Asswairy #1, Tasour #7 and Tasour #8, facility expansion, water disposal well, additional working interest payment described below and various well workovers. Capital expenditures of $1,472,611 in 2001 on Block 32 were incurred on a three well drilling program comprised of Tasour #5, Tasour #6 and a portion of Asswairy #1, plus a 120 kilometer 2-D seismic program.

Effective January 1, 2000, the Company entered into an agreement to purchase an additional 4% working interest in Block 32 for a total purchase price of $2,136,163, increasing the Company's working interest to 13.81087%. The Company made an initial payment of $1,176,163. A potential future obligation totalling $960,000 will be due in six payments of $160,000 for each cumulative million barrels of gross oil production commencing at 7 million barrels to a maximum of 12 million barrels. The purchase also includes the proportionate historical cost pools attributable to the interest acquired. During 2002 the Company made the first payment of $160,000 and subsequent to December 31, 2002 a second and a third payment of $160,000 each were made. The Company expects that the remaining payments will be made during 2003.

On Block S-1 the Company incurred $3,404,599 primarily on drilling three wells comprised of Osaylan #1, An Nagyah #2 and An Naeem #3, contractual government payments, pre-drilling inventory and geological / geophysical / geochemical studies. Capital expenditures on Block S-1 in 2001 were $1,890,684 primarily on field acquisition of a 230 square kilometer 3-D seismic program, Harmel #1 production test and various contractual government payments.

Canadian capital expenditures of $1,041,146 in 2002 relate to several mineral lease acquisitions, drilling two wells at Nevis and one well at Morningside and tie in costs at Cherhill, Morinville and Morningside areas.

Dispositions

Proceeds on disposal of oil and gas properties represent dispositions in Canada of minor properties at Wildmint and Provost in 2002.

FINDING AND DEVELOPMENT COSTS

	Three Year Average	**2002**	2001	2000
Total capitalized costs		**$ 6,476,544**	$ 4,782,251	$ 5,973,407
Proved reserve additions and revisions (MBoe)		**1,209.7**	946.2	754.3
Proved plus probable reserve additions and revisions (MBoe)		**1,390.2**	700.5	1,075.3
Average cost per Boe - proved	**$ 5.92**	**$ 5.35**	$ 5.05	$ 7.92
- proved plus probable	**$ 5.44**	**$ 4.66**	$ 6.83	$ 5.55

RECYCLE RATIO

	Three Year Average	**2002**	2001	2000
Netback ($/Boe)	**$ 13.14**	**$ 15.36**	$ 11.69	$ 7.56
Proved finding and development costs ($/Boe)	**$ 5.92**	**$ 5.35**	$ 5.05	$ 7.92
Recycle ratio	**2.22**	**2.87**	2.31	0.95

The recycle ratio measures the efficiency of TransGlobe's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the netback by the proved finding and development cost on a Boe basis. Netback is defined as net sales revenues less operating, general and administrative, foreign exchange (gain) loss, interest and current income tax expense per Boe of production.

LIQUIDITY AND CAPITAL RESOURCES

Funding for the Company's capital expenditures in 2002 was provided by cash flow from operations and working capital.

At December 31, 2002 the Company had working capital of $4,748,933, nil debt and a revolving credit facility of Cdn$2,500,000 and an acquisition/development credit facility of Cdn$2,000,000.

The Company expects to fund its 2003 exploration and development program (budgeted at $10 million firm and contingent) through the use of working capital, cash flow and debt as required. Should cash flow be negatively impacted by reduction in production volumes or commodity prices, the Company has significant flexibility to adjust its Canadian capital budget of $2.7 million.

In December 2002, the Company announced the approval of a Normal Course Issuer Bid to acquire up to 4,855,435 common shares over a 12 month period expiring December 8, 2003. In 2003 the Company acquired 100,000 common shares at a price of Cdn$0.60/share. The acquired shares have been returned to treasury and cancelled.

COMMITMENTS AND CONTINGENCIES

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

	2003	2004	2005	2006	2007
Office and equipment leases	$ 112,000	$ 114,000	$ 114,000	$ 114,000	$ 40,000
Expected contingent payments on Block 32 additional interest acquisition in 2000	800,000(1)	-	-	-	-
	$ 912,000	$ 114,000	$ 114,000	$ 114,000	$ 40,000

(1) In 2003, $320,000 has been paid to date.

The Block S-1 second exploration period letter of credit issued in 2002 in the amount of $1,500,000, was fully released in 2003.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 1 of the Consolidated Financial Statements.

Oil and Gas Reserves Determination

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available, and as economic conditions impact oil and gas prices and costs.

Full Cost Accounting for Oil and Gas Activities

Depletion and Depreciation Expense

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs, estimated future development costs and estimated future site restoration costs is amortized using the unit of production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves will result in a corresponding reduction in depletion and depreciation expense. A decrease in estimated future development costs will result in a corresponding reduction in depletion and depreciation expense.

Unproven Properties

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion and depreciation until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Ceiling Test

The full cost method of accounting requires the calculation of a ceiling test which limits the net capital costs carried to an amount that is equal to the estimated future net revenues from the Company's oil and gas properties plus the cost (net of impairment) of unproved properties. The test is a cost recovery test and is not intended to represent an estimate of fair market value. The test is performed quarterly. If the net carrying cost of the oil and gas properties exceeds the indicated limit then the difference is charged to earnings.

RISKS

The Company is exposed to a variety of business risks and uncertainties in the international petroleum industry including commodity prices, exploration success, production risk, foreign exchange, interest rates, government regulation, changes of laws affecting foreign ownership, political risk of operating in foreign jurisdictions, taxes, environmental preservation and safety concerns.

Many of these risks are not within the control of management, but the Company has adopted several strategies to reduce and minimize the effects of these factors:

- The Company applies rigorous geological, geophysical and engineering analysis to each prospect.
- The Company utilizes its in-house expertise for all international ventures and employs and contracts professionals to handle each aspect of the Company's business.
- The Company maintains U.S. dollar bank accounts which is its main operating currency.
- The Company maintains a conservative approach to debt financing and currently has no long-term debt.
- The Company maintains insurance according to customary industry practice, but cannot fully insure against all risks.
- The Company conducts its operations to ensure compliance with governmental regulations and guidelines.
- The Company retains independent petroleum engineering consultants to determine year-end Company reserves and estimated future net revenues.

QUARTERLY FINANCIAL SUMMARY

	2002			
	Q-4	**Q-3**	**Q-2**	**Q-1**
Oil and gas sales, net of royalties	**$5,459,364**	**$2,964,411**	**$2,859,258**	**$1,971,072**
Cash flow from operations	**$4,380,792**	**$2,111,302**	**$1,951,125**	**$1,266,633**
Cash flow from operations per share				
- Basic	**$ 0.09**	**$ 0.04**	**$ 0.04**	**$ 0.02**
- Diluted	**$ 0.09**	**$ 0.04**	**$ 0.04**	**$ 0.02**
Net income	**$3,197,791**	**$1,040,470**	**$ 873,125**	**$ 315,003**
Net income per share				
- Basic	**$ 0.07**	**$ 0.02**	**$ 0.02**	**$ 0.01**
- Diluted	**$ 0.06**	**$ 0.02**	**$ 0.02**	**$ 0.01**

	2001			
	Q-4	Q-3	Q-2	Q-1
Oil and gas sales, net of royalties	$ 1,647,479	$ 1,928,521	$ 2,488,120	$ 2,489,965
Cash flow from operations	$ 1,029,365	$ 1,266,471	$ 1,805,319	$ 1,739,300
Cash flow from operations per share				
- Basic	$ 0.02	$ 0.03	$ 0.04	$ 0.03
- Diluted	$ 0.02	$ 0.02	$ 0.04	$ 0.03
Net income	$ 337,365	$ 685,471	$ 1,034,101	$ 1,005,300
Net income per share				
- Basic	$ 0.01	$ 0.01	$ 0.02	$ 0.02
- Diluted	$ 0.01	$ 0.01	$ 0.02	$ 0.02

Management's Report

The consolidated financial statements of TransGlobe Energy Corporation were prepared by management within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of consolidated financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by the shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of three independent directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements.

Ross G. Clarkson
President &
Chief Executive Officer

David C. Ferguson
Vice President, Finance &
Chief Financial Officer

February 28, 2003

Auditors' Report

To the Shareholders of
TransGlobe Energy Corporation:

*We have audited the consolidated balance sheets of **TransGlobe Energy Corporation** as at December 31, 2002 and 2001 and the consolidated statements of income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.*

We conducted our audits in accordance with Canadian and United States generally accepted auditing standards. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied, except for the accounting policy change as described in Note 1 to the consolidated financial statements, on a consistent basis.

Deloitte & Touche LLP

Calgary, Alberta
February 28, 2003

Chartered Accountants

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA- U.S. REPORTING DIFFERENCES

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting policies that have been implemented in the financial statements. As discussed in Note 1 to the consolidated financial statements, in 2002 the Company has adopted the new Canadian Institute of Chartered Accountants Handbook recommendations for stock compensation.

Deloitte & Touche LLP

Calgary, Alberta
February 28, 2003

Chartered Accountants

Consolidated Statements of Income and Deficit

(Expressed in U.S. Dollars)

	Year Ended December 31, 2002	Year Ended December 31, 2001
REVENUE		
Oil and gas sales, net of royalties	**$ 13,254,105**	$ 8,554,085
Other income	**42,108**	16,470
	13,296,213	8,570,555
EXPENSES		
Operating	**1,843,273**	1,540,369
General and administrative	**820,691**	570,609
Foreign exchange (gain) loss	**(6,988)**	(3,800)
Interest	**16,154**	4,424
Depletion and depreciation	**4,277,000**	2,762,000
	6,950,130	4,873,602
Net income before income taxes	**6,346,083**	3,696,953
Income taxes (Note 6)		
- future	**(67,168)**	-
- current	**986,862**	634,716
	919,694	634,716
NET INCOME	**5,426,389**	3,062,237
Deficit, beginning of year	**(17,724,698)**	(20,786,935)
Deficit, end of year	**$ (12,298,309)**	$ (17,724,698)
Net income per share (Note 8)		
Basic	**$ 0.11**	$ 0.06
Diluted	**$ 0.10**	$ 0.06

Consolidated Balance Sheets

(Expressed in U.S. Dollars)

	December 31, 2002	December 31, 2001
ASSETS		
Current		
Cash	**$ 2,595,170**	$ 1,174,846
Accounts receivable	**2,984,000**	975,773
Prepaid expenses	**88,837**	60,687
	5,668,007	2,211,306
Capital assets		
Canada (Note 2)	**3,651,305**	3,044,746
Republic of Yemen (Note 3)	**15,066,835**	13,591,437
	18,718,140	16,636,183
	$ 24,386,147	$ 18,847,489
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 919,074**	$ 828,959
Provision for site restoration and abandonment	**122,209**	106,209
	1,041,283	935,168
SHAREHOLDERS' EQUITY		
Share capital (Note 5)	**35,643,173**	35,637,019
Deficit	**(12,298,309)**	(17,724,698)
	23,344,864	17,912,321
	$ 24,386,147	$ 18,847,489

APPROVED BY THE BOARD

Ross G. Clarkson, Director

Lloyd W. Herrick, Director

Consolidated Statements of Cash Flows

(Expressed in U.S. Dollars)

	Year Ended December 31, 2002	Year Ended December 31, 2001
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net income	**$ 5,426,389**	$ 3,062,237
Adjustments for:		
Depletion and depreciation	**4,277,000**	2,762,000
Performance bonus expense paid in shares (Note 5)	**73,631**	16,218
Future income taxes	**(67,168)**	-
Cash flow from operations (Note 8)	**9,709,852**	5,840,455
Changes in non-cash working capital (Note 7)	**(2,478,700)**	621,196
	7,231,152	6,461,651
FINANCING		
Issue of share capital (Note 5)	**(308)**	210,797
Issuance (repayment) of long-term debt	**-**	(77,634)
	(308)	133,163
INVESTING		
Purchase of capital assets		
Yemen	**(5,435,398)**	(3,406,363)
Canada	**(1,041,146)**	(1,375,888)
Proceeds on disposal of oil and gas properties	**133,587**	-
Changes in non-cash working capital (Note 7)	**532,437**	(702,631)
	(5,810,520)	(5,484,882)
NET INCREASE IN CASH	**1,420,324**	1,109,932
CASH, BEGINNING OF YEAR	**1,174,846**	64,914
CASH, END OF YEAR	**$ 2,595,170**	$ 1,174,846
Cash flow from operations per share (Note 8)		
Basic	**$ 0.19**	$ 0.12
Diluted	**$ 0.19**	$ 0.11

Notes to the Consolidated Financial Statements

Years Ended December 31, 2002 and December 31, 2001

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, TransGlobe Oil and Gas Corporation, TransGlobe Petroleum International Inc., TransGlobe International (Holdings) Inc., and TG Holdings Yemen Inc.

Accounting principles

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada, which conform in all material respects with accounting principles generally accepted in the United States, except as disclosed in Note 14.

Oil and gas properties

The Company follows the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

The capitalized costs, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on the estimated gross proven reserves and determined by independent petroleum engineers. Oil and gas reserves and production were converted into equivalent units of 6,000 cubic feet of natural gas to one barrel of oil based upon relative energy content.

Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation. These costs are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and depreciation.

The capitalized costs less accumulated depletion and depreciation, future income taxes and the provision for future site restoration costs in each cost centre are limited to an amount equal to the estimated future net revenue from proven reserves plus the cost (net of impairment) of unproven properties.

The total capitalized costs less accumulated depletion and depreciation, future income taxes and the provision for future site restoration costs of all cost centres is further limited to an amount equal to the estimated future net revenue from proven reserves plus the cost (net of impairment) of unproven properties of all costs centres less estimated future site restoration costs, general and administrative expenses, financing costs and income taxes.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Estimated future site restoration costs are provided for using the unit-of-production method and remaining proven reserves. Costs are estimated by the Company based on current regulations, costs, technology and industry standards. The annual charge is included in the provision for depletion and depreciation. Actual site restoration expenditures are charged to the accumulated provision account as incurred.

Furniture and fixtures are depreciated at declining balance rates of 20 to 30 percent.

Foreign currency

The Company uses the United States dollar as its reporting currency since the majority of the Company's business is transacted in United States dollars. The Company and its subsidiaries are considered to be integrated operations and the accounts are translated using the temporal method. Under this method, monetary assets and liabilities are translated at the rates of exchange in effect at the balance sheet date; non-monetary assets at historical rates and revenue and expense items at the average rates for the period, other than depletion and depreciation which are translated at the same rates of exchange as the related asset. The net effect of the foreign currency translation is included in current operations.

Cash and cash equivalent

Cash includes actual cash held and short-term investments such as treasury bills with maturity of less than three months.

Revenue recognition

The Company records oil and gas revenue at the time of physical transfer to purchaser.

Income taxes

The Company records income taxes using the liability method. Under this method, future income tax assets and liabilities are measured using the enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

Flow through shares

The Company has financed a portion of its exploration and development activities in Canada through the issue of flow through shares. Under the terms of these share issues, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded as the related expenditures are made. The Company has sufficient tax losses for which the future tax benefit is not recorded to offset the increase in future taxes due to the renouncement of expenditures.

Stock options

The Company has a stock option plan as described in Note 5. No compensation expense has been recorded upon the granting of the options at market prices. Effective January 1, 2002, the Company adopted CICA 3870 "Stock Based Compensation and Other Stock Based Payments". As permitted by CICA 3870, the Company has applied this change prospectively for new awards granted on or after January 1, 2002. For 2002 the Company has calculated the impact on net earnings and earnings per share on a proforma basis (Note 5(g)). For periods prior to January 1, 2002 the Company did not recognize any compensation expense when stock options were issued to employees.

Per share amounts

Net income and cash flow from operations per share are calculated using the weighted average number of shares outstanding during the year. Diluted net income and cash flow from operations per share are calculated using the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment, the provision for site restoration costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future periods could be significant.

2. CAPITAL ASSETS - CANADA

	2002	2001
Oil and gas properties	**$ 4,618,485**	$ 3,725,222
Furniture and fixtures	**201,539**	187,243
Accumulated depletion and depreciation	**(1,168,719)**	(867,719)
	$ 3,651,305	$ 3,044,746

During the year the Company capitalized overhead costs relating to exploration and development activities of $153,569 (2001 - $156,311).

Depletion and depreciation expense includes $16,000 (2001 - $24,000) related to the provision for site restoration which is calculated based on a total future estimated cost of $319,000 (2001 - $297,000).

3. CAPITAL ASSETS - REPUBLIC OF YEMEN

	2002	2001
Block 32	**$ 13,575,336**	$ 11,553,012
Block S-1	**8,016,556**	4,611,957
Other	**81,943**	73,468
Accumulated depletion and depreciation	**(6,607,000)**	(2,647,000)
	$ 15,066,835	$ 13,591,437

The Company commenced production on Block 32 in November 2000. This represents the early stages of a major development program contracted under the Production Sharing Agreement ("PSA") for the next twenty years. On Block S-1, the second period of the exploration program will be undertaken during 2002, 2003 and 2004. The Company and its partner on Block S-1 have elected to enter the second exploration period effective March 28, 2002. Unproven properties in the amount of $7,184,372 were excluded from costs subject to depletion and depreciation representing a portion of the costs incurred in Block S-1. During the year the Company capitalized overhead costs relating to exploration and development activities of $238,834 (2001 - $258,982).

Block 32

The PSA provides for the Ministry of Oil and Mineral Resources (the "MOM") in the Republic of Yemen to receive a royalty of 3% (10% over 25,000 barrels of oil per day ("Bopd")) of gross production with the remaining 97% of revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of 97% of the revenue limited to operating costs and allocated recoverable exploration and development expenditures as outlined in the PSA. Cost recovery oil is 100% for the account of the Block 32 Contractor (Joint Venture Partners) to recover operating costs and exploration and development expenditures. The remaining production sharing oil is shared 65% by MOM and 35% by the Block 32 Contractor which is further shared 5% Yemen Oil Company ("YOC")/95% Block 32 Contractor. These terms remain in place as long as proven recoverable reserves do not exceed 30 million barrels of oil (gross) or production of 25,000 Bopd.

Block S-1

The PSA provides MOM with a sliding scale royalty of 3%-10% based on daily oil production between 0-100,000 Bopd with the remaining revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 50% of after royalty revenue limited to operating costs and allocated recoverable exploration and development expenditures, as outlined in the PSA, to be utilized 100% by the Block S-1 Contractor. The balance of the revenue is allocated to production sharing oil and is shared 65%-80% by MOM and 35%-20% by the Block S-1 Contractor (which is further shared 17.5% YOC/82.5% Block S-1 Contractor) based on the production level.

4. LONG-TERM DEBT

Effective January 1, 2002, Canadian accounting standards require that revolving debt with terms of 364 days or less is to be included in current liabilities.

The Company has a Cdn$2,500,000 revolving loan facility and a Cdn$2,000,000 non-revolving acquisition/development facility with a Canadian chartered bank. The loan facilities bear interest at the bank's Canadian prime rate plus three quarters of one percent and Canadian prime rate plus one percent, respectively, and are secured by a first floating charge debenture over all Canadian assets of the Company, a general assignment of book debts and certain negative pledges. At December 31, 2002 $nil (2001 - $nil) was drawn on these loan facilities.

The Company has a $1,500,000 letter of credit issued in support of the commitments of the second exploration period on Block S-1 in the Republic of Yemen which is secured by a guarantee obtained from Export Development Canada. Subsequent to December 31, 2002 this letter of credit was reduced to $750,000 (see Note 10).

5. SHARE CAPITAL

a) Authorized

The authorized share capital is 500,000,000 common shares with no par value.

b) Issued

	Number of Shares	Amount
Balance, December 31, 2000	50,500,801	**$ 35,410,004**
Exercise of stock options (e)	125,000	**27,500**
Exercise of warrants (f)	50,000	**27,500**
Performance bonus expense paid in shares (d)	50,000	**16,218**
Private placement, net of issue costs (c)	519,000	**155,797**
Balance, December 31, 2001	51,244,801	**35,637,019**
Future tax effect (c)	-	**(67,168)**
Share issue costs	-	**(309)**
Performance bonus expense paid in shares (d)	250,000	**73,631**
Balance, December 31, 2002	51,494,801	**$ 35,643,173**

c) In December 2001, the Company issued 519,000 flow through common shares in a private placement at Cdn$0.49 per share for net proceeds of US$155,797, subscribed by insiders of the Company. The terms of the flow through shares provide that the Company renounce Canadian tax deductions in the amount of Cdn$254,310 to the subscribers with the entire amount to be expended by the Company by December 31, 2002. As at December 31, 2002, the entire amount was spent. As described in Note 1, share capital is reduced and future income taxes are increased by the estimated amount of the future income taxes payable by the Company ($67,168) as a result of renouncing the expenditures to subscribers.

d) Pursuant to an employment contract and the Company meeting certain performance criteria, the Company issued 250,000 and 50,000 common shares to the President of the Company in 2002 and 2001, respectively, recorded at market prices at respective dates of issue.

e) Share purchase options

The Company established a stock option plan in April 1997, with subsequent amendments (the "Plan"). The maximum number of common shares to be issued upon the exercise of options granted under the Plan is 5,052,580 common shares. All incentive stock options granted under the Plan will have a per-share exercise price not less than the trading market value of the common shares at the date of grant and will vest as to 50% of the options, six months after the grant date, and as to the remaining 50%, one year from the grant date.

	2002		2001	
	Number of Options	**Weighted-Average Exercise Price**	Number of Options	Weighted-Average Exercise Price
Options outstanding at beginning of year	**2,379,500**	**$ 0.31**	2,806,500	$ 0.32
Granted	**1,400,000**	**0.32**	240,000	0.34
Exercised	**-**	**-**	(125,000)	0.22
Expired	**(155,000)**	**0.22**	(542,000)	0.38
Options outstanding at end of year	**3,624,500**	**$ 0.32**	2,379,500	$ 0.31
Options exercisable at end of year	**2,924,500**		2,239,500	

The following table summarizes information about the stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding at Dec. 31, 2002	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at Dec. 31, 2002	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$ 0.22	1,285,000	0.7	$ 0.22	1,285,000	0.7	$ 0.22
Cdn 0.45	20,000	1.8	Cdn 0.45	20,000	1.8	Cdn 0.45
Cdn 0.55	200,000	3.4	Cdn 0.55	200,000	3.4	Cdn 0.55
Cdn 0.39	40,000	3.8	Cdn 0.39	40,000	3.8	Cdn 0.39
Cdn 0.73	679,500	2.6	Cdn 0.73	679,500	2.6	Cdn 0.73
Cdn 0.50	1,400,000	4.3	Cdn 0.50	700,000	4.3	Cdn 0.50
	3,624,500	2.7	$ 0.32	2,924,500	2.3	$ 0.32

f) Share purchase warrants

The following table summarizes the share purchase warrants exercised and expired during the years ended and as at December 31, 2002 and 2001:

Number of Warrants						
Dec. 31, 2001	Granted	Expired	Exercised	**Dec. 31, 2002**	Warrant Price	Expiry Date
2,139,806	-	2,139,806	-	-	Cdn$ 1.15	Jan. 27, 2002
775,000	-	775,000	-	-	$ 0.55	Aug. 25, 2002
1,500,000	-	1,500,000	-	-	$ 0.47	Sept. 8, 2002
4,414,806	-	4,414,806	-	-		

Number of Warrants						
Dec. 31, 2000	Granted	Expired	Exercised	Dec. 31, 2001	Warrant Price	Expiry Date
2,139,806	-	-	-	2,139,806	Cdn$ 1.15	Jan. 27, 2002
875,000	-	50,000	50,000	775,000	$ 0.55	Aug. 25, 2002
1,500,000	-	-	-	1,500,000	$ 0.47	Sept. 8, 2002
4,514,806	-	50,000	50,000	4,414,806		

g) Stock-based compensation

The Company accounts for its stock-based compensation plans using the intrinsic-value of the options granted whereby no costs have been recognized in the financial statements for stock options granted to employees and directors at market values. Effective January 1, 2002 under Canadian generally accepted accounting principles, the impact of using the fair value method on compensation costs and recorded net earnings must be disclosed. If the fair value method had been used, the Company's net earnings per share would approximate the following pro forma amounts (the pro forma amounts shown do not include the compensation costs associated with stock options granted prior to January 1, 2002):

	2002
Compensation costs	**$ 140,000**
Net earnings:	
As reported	**5,426,389**
Pro forma	**5,286,389**
Net earnings per common shares:	
As reported - Basic	**$ 0.11**
- Diluted	**$ 0.10**
Pro forma - Basic and diluted	**$ 0.10**

The fair value of each option granted on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants is as follows:

Risk free interest rate (%)	5.05
Expected lives (years)	5.00
Expected volatility (%)	66.35
Dividend per share	0.00

6. INCOME TAXES

The Company has deductible temporary differences for which no future income tax asset has been recorded. Those deductible temporary differences are Cdn$2,260,000 in non-capital losses and approximately Cdn$5,645,000 of income tax pools in excess of the carrying value of the Company's Canadian capital assets. The Company also has $13,100,000 of income tax losses in the United States. The Canadian loss carryforwards expire between 2006 and 2010 and the United States loss carryforwards expire between 2006 and 2020. In total, these temporary differences would generate a future income tax asset of Cdn$3,624,400 on Canadian operations for which a valuation allowance of an identical amount would be recorded.

Current income taxes in the amount of $986,862 (2001 - $634,716) represents income taxes incurred and paid under the laws of the Republic of Yemen.

The components of expected income tax expense are as follows:

	2002	2001
Computed Canadian expected income tax expense at 42.15% (2001 - 42.67%)	**$ 2,674,874**	$ 1,577,490
Non-deductible Crown charges (net of ARTC)	**64,036**	127,518
Resource allowance	**(2,773)**	(99,174)
Lower tax rates in the Republic of Yemen	**(1,872,869)**	(829,858)
Future income taxes recovered	**(67,168)**	-
Other	**123,594**	(141,260)
	$ 919,694	$ 634,716

7. SUPPLEMENTAL CASH FLOW INFORMATION

	2002	2001
Operating activities		
Decrease (increase) in current assets		
Accounts receivable	**$ (2,317,826)**	$ 732,992
Prepaid expenses	**(28,150)**	(9,577)
Increase (decrease) in current liabilities		
Accounts payable	**(132,724)**	(102,219)
	$ (2,478,700)	$ 621,196
Investing activities		
Decrease (increase) in current assets		
Accounts receivable	**$ 309,598**	$ (91,856)
Increase (decrease) in current liabilities		
Accounts payable	**222,839**	(610,775)
	$ 532,437	$ (702,631)
Interest paid	**$ 16,154**	$ 4,424
Taxes paid	**$ 986,862**	$ 634,716

8. NET INCOME AND CASH FLOW PER SHARE

	2002	2001
Basic		
Net income per share	**$ 0.11**	$ 0.06
Cash flow from operations per share	**$ 0.19**	$ 0.12
Weighted average number of shares outstanding	**51,449,596**	50,640,877
Diluted		
Net income per share	**$ 0.10**	$ 0.06
Cash flow from operations per share	**$ 0.19**	$ 0.11
Weighted average number of shares outstanding	**51,944,926**	51,118,289

9. SEGMENTED INFORMATION

In 2002 the Company operated in two geographic segments, Canada and the Republic of Yemen. The capital assets in each geographic segment are disclosed in Notes 2 and 3. The Company's revenue in the Republic of Yemen is based on a 30 day dated Brent average oil price less pricing quality differential and is paid monthly by operator.

The results of operations for the year ended December 31, 2002 are comprised of the following:

	Republic of Yemen	Canada	Total
REVENUE			
Oil and gas sales, net of royalties	**$ 12,238,711**	**$ 1,015,394**	**$ 13,254,105**
EXPENSES			
Operating	**1,394,379**	**448,894**	**1,843,273**
Depletion and depreciation	**3,960,000**	**317,000**	**4,277,000**
Segmented operations	**$ 6,884,332**	**$ 249,500**	**7,133,832**
Other income			**42,108**
			7,175,940
General and administrative			**820,691**
Foreign exchange (gain) loss			**(6,988)**
Interest			**16,154**
Income taxes (Note 6)			**919,694**
NET INCOME			**$ 5,426,389**

The results of operations for the year ended December 31, 2001 are comprised of the following:

	Republic of Yemen	Canada	Total
REVENUE			
Oil and gas sales, net of royalties	$ 7,000,676	$ 1,553,409	$ 8,554,085
EXPENSES			
Operating	1,133,092	407,277	1,540,369
Depletion and depreciation	2,405,000	357,000	2,762,000
Segmented operations	$ 3,462,584	$ 789,132	4,251,716
Other income			16,470
			4,268,186
General and administrative			570,609
Foreign exchange (gain) loss			(3,800)
Interest			4,424
Income taxes (Note 6)			634,716
NET INCOME			$ 3,062,237

10. COMMITMENTS AND CONTINGENCIES

The Company is committed to office and equipment leases over the next five years as follows:

2003	$112,000
2004	114,000
2005	114,000
2006	114,000
2007	40,000

The Company has issued a three year letter of credit in the amount of $1,500,000 in support of the commitments of the second exploration period on Block S-1 in the Republic of Yemen. This letter of credit is secured by a guarantee obtained from Export Development Canada. The Company's obligation to Export Development Canada is secured by a first floating charge debenture (subordinated to the Bank's interest in the Canadian assets and first to the foreign assets). The Block S-1 second exploration period commitments were fulfilled during 2002 and subsequent to December 31, 2002 the Company's letter of credit was reduced to $750,000. It is expected that the remaining balance of $750,000 will be released in the first quarter of 2003.

Effective January 1, 2000, the Company entered into an agreement to purchase an additional four percent working interest, increasing the Company's working interest to 13.81087% in Block 32 for a total purchase price of $2,136,163. The Company made an initial payment of $1,176,163. A potential future obligation totalling $960,000 will be due in six payments of $160,000 for each cumulative million barrels of gross oil production from Block 32 commencing at 7 million barrels to a maximum of 12 million barrels. During 2002 the Company made the first payment of $160,000 and subsequent to December 31, 2002 a second payment of $160,000 was made. The Company expects that the remaining payments will be made during 2003.

11. FINANCIAL INSTRUMENTS

Carrying values of financial instruments, which include accounts receivable, accounts payable and accrued liabilities approximate their fair value due to the short-term or the floating interest rate nature of these amounts.

The Company has foreign exchange risk due to the fact that it operates internationally using foreign currencies. The Company has commodity price risk associated with its sale of crude oil and natural gas.

The majority of the accounts receivable are in respect of oil and gas operations. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any material credit loss in the collection of accounts receivable to date.

12. COMPARATIVE FIGURES

Certain of the prior period's comparative figures have been reclassified to conform with the current period's presentation.

13. SUBSEQUENT EVENT

Subsequent to December 31, 2002, the Company entered into a contract to sell 500 gigajoules (GJ) per day of natural gas in Canada from March 1 to October 31, 2003 for Cdn$7.65/GJ.

14. DIFFERENCES BETWEEN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA AND THE UNITED STATES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP) which differ in certain respects from those principles and practices that the Company would have followed had its consolidated financial statements been prepared in accordance with United States generally accepted accounting principles and practices (U.S. GAAP).

Escrowed shares

For U.S. GAAP purposes, escrowed shares would be considered a separate compensatory arrangement between the Company and the holder of the shares. Accordingly, the fair market value of shares at the time the shares are released from escrow will be recognized as a charge to income in that year with a corresponding increase in share capital. The difference in share capital between Canadian GAAP and U.S. GAAP represents the effect of applying this provision in 1995 when 187,500 escrow shares were released resulting in an increase in share capital of $833,333 with the offset to deficit.

Stock based compensation

In 1995, the United States Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation." The Company has a stock-based compensation plan as more fully described in Note 5. With regard to its stock option plan, the Company applies APB Opinion No. 25 as interpreted by FASB Interpretation No. 44 in accounting for this plan and accordingly no compensation cost has been recognized. Had compensation expense been determined based on fair value at the grant dates for the stock option grants consistent with the method of SFAS No. 123, the Company's net income would have been decreased by $171,000 (December 31, 2001 net income would have been decreased by $302,000). Basic net income per share would have been reduced to $0.10 and diluted net income per share would be unchanged (2001 basic and diluted net income per share would have been reduced to $0.05).

The foregoing information is calculated in accordance with the Black-Scholes option pricing model, using the following data and assumptions: volatility, as of the date of grant, computed using the prior one to three-year monthly average prices of the Company's common shares, which ranged from 113% to 114%; expected dividend yield - 0%; option terms to expiry - 5 years as defined by the option contracts; risk-free rate of return as of the date of grant - 5.05% to 6.03%.

Gain on sale of oil and gas properties

The Company sold all of its oil and gas properties in the United States in the year 2000. The gain on sale under United States GAAP was $145,000 less than under Canadian GAAP arising from ceiling test differences. Under SEC regulations, the future net revenue as calculated for the ceiling test excludes future overhead costs and must be discounted at 10%. This is not required under Canadian GAAP. The effect of applying this provision to the Company's financial statements in previous years resulted in a higher net book value of capital assets in the United States by $145,000.

Flow through shares

The Company records the renouncement of deductions related to flow through shares by reducing the share capital and recording a future tax liability in the amount of the estimated cost of the tax deductions flowed to the shareholders in the period in which the expenditures are renounced. United States practice requires that the share capital on flow through shares be stated at the quoted market value of the shares at the date of issuance. In addition, the temporary difference that arises as a result of the renouncement of the deductions, less any proceeds received in excess of the quoted market value of the shares is recognized in the determination of income tax expense for the period. In 2000, the effect of applying this provision to the Company's financial statements would result in an increase in income tax expense and future tax liability by $335,020 representing the tax effect of the flow through shares and a corresponding decrease to income tax expense and future tax liability by $335,020 to record the recognition of the benefit of tax losses available to the Company equal to the liability arising from renouncing tax pools to the subscribers. In 2002, the effect of applying this provision to the Company's financial statements would result in an increase in income tax expense and future tax liability by $67,168 representing tax effect of the flow through shares and a corresponding decrease to income tax expense and future tax liability by $67,168 to record the recognition of the benefit of tax losses available to the Company equal to the liability arising from renouncing tax pools to the subscriber.

Had the Company followed U.S. GAAP, the shareholders' equity would have been reported as follows:

	2002		2001	
	Cdn. GAAP	**U.S. GAAP**	Cdn. GAAP	U.S. GAAP
Share capital	**$ 35,643,173**	**$ 36,878,694**	$ 35,637,019	$ 36,805,372
Deficit	**(12,298,309)**	**(13,533,830)**	(17,724,698)	(18,893,051)
	$ 23,344,864	**$ 23,344,864**	$ 17,912,321	$ 17,912,321

The reconciling items between share capital and deficit for Canadian and United States GAAP are $833,333 related to escrowed shares and $402,188 related to flow through shares as described above. There are no other balance differences.

Had the Company followed U.S. GAAP, the statement of operations would have been reported as follows:

	2002	2001
Net income for the year under Canadian GAAP	**$ 5,426,389**	$ 3,062,237
Net income for the year under U.S. GAAP	**5,359,221**	3,062,237
Net income per share under U.S. GAAP	**$ 0.10**	$ 0.06

Recent accounting pronouncements

In August 2001, the FASB approved SFAS No. 143, "Accounting for Asset Retirement Obligations", which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Management does not believe that SFAS No. 143 will have a material impact on the Company's financial statements.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", resolving significant implementation issues related to FASB Statement No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of", and supersedes the accounting and reporting provisions of APB Opinion No. 30, "Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions", for the disposal of a business segment. SFAS No. 144 is effective for the fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. Management does not believe that SFAS No. 144 will have material impact on the Company's financial statements.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt", addressed income statement classification of gains and losses from extinguishment of debt. SFAS No. 64 amended SFAS No. 4 and is no longer necessary due to the rescission of SFAS No. 4. SFAS No. 145 also amended SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. Management believes that SFAS No. 145 will have no retroactive impact on the Company's financial statements.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities", which requires the recognition of a liability when incurred for costs associated with an exit or disposal activity. Management does not believe that SFAS No. 146 will have a material impact on the Company's financial statements.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-based Compensation Transition and Disclosure - an Amendment of FASB Statement No. 123", to provide alternative methods of accounting for stock-based employee compensation. SFAS No. 148 is effective for fiscal years ending after December 15, 2002 and interim periods beginning after December 15, 2002. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No.123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Management does not believe that SFAS No. 148 will have a material impact on the Company's financial statements.

Corporate Information

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Robert A. Halpin,
Director, Chairman of the Board

Ross G. Clarkson
Director, President & CEO

Lloyd W. Herrick
Director, Vice President & COO

Erwin L. Noyes
Director

Geoffrey C. Chase
Director

David C. Ferguson
Vice President, Finance, CFO & Secretary

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AUDITOR

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Outtrim Szabo Associates Ltd.
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