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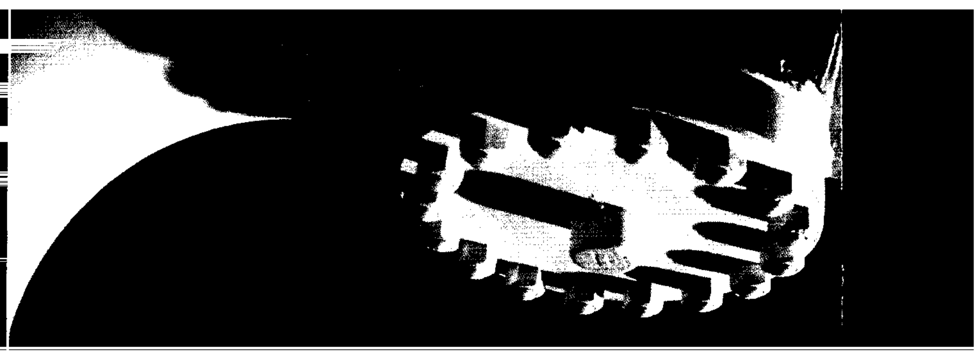
TIPPERARY CORPORATION ANNUAL REPORT 2001

about the company

Tipperary Corporation is an independent energy company focused primarily on exploration for, and production of, coalbed methane and conventional natural gas. Headquartered in Denver, Colorado, Tipperary owns 90% of Queensland, Australia-based Tipperary Oil & Gas (Australia) Pty Ltd. This subsidiary, which holds a 65% interest in southeastern Queensland's Comet Ridge coalbed methane project, also holds other exploration permits in Queensland totaling approximately 1.5 million acres. Domestically, Tipperary holds interests in several exploration projects in Colorado and Wyoming covering approximately 385,000 acres.



financial summary

Statement of operations data

	2001	Oct-Dec 2000*	2000	1999	1998	1997
Revenues	$ 3,557	$ 864	$ 8,624	$ 7,921	$ 9,082	$ 12,951
Net income (loss)	$ (7,176)	$ (1,120)	$ 43	$ (9,295)	$ (6,398)	$ 472
Net income (loss) per common share-basic and diluted	$ (.28)	$ (.05)	$ --	$ (.63)	$ (.49)	$ .04
Weighted average shares outstanding	25,842	24,471	21,204	14,689	13,118	13,050

* The quarter represents the transition period resulting from the Company's decision to change its fiscal year end from September 30 to December 31.

Balance sheet data

	2001	Oct-Dec 2000*	2000	1999	1998	1997
Total assets	$ 77,527	$ 53,350	$ 52,546	$ 48,005	$ 50,760	$ 54,995
Total long-term debt	$ 12,183	$ 11,589	$ 10,633	$ 21,265	$ 19,200	$ 13,844
Working capital	$ 8,868	$ 2,256	$ 6,841	$ 270	$ 1,045	$ 1,381
Working capital provided (used) by operations	$ (5,239)	$ (981)	$ 1,617	$ (515)	$ 1,015	$ 5,201
Stockholders' equity	$ 57,119	$ 37,519	$ 38,635	$ 23,452	$ 30,280	$ 36,488

* The quarter represents the transition period resulting from the Company's decision to change its fiscal year end from September 30 to December 31.

Dear shareholder:

I am pleased to provide you with this review of our fiscal year ended December 31, 2001. I should note this is our first report since changing our fiscal year to correspond with the calendar year. This change will provide more useful comparative data as you analyze Tipperary against other companies. This letter addresses the progress and direction of the Company and is followed by a copy of our year-end report to the Securities and Exchange Commission.

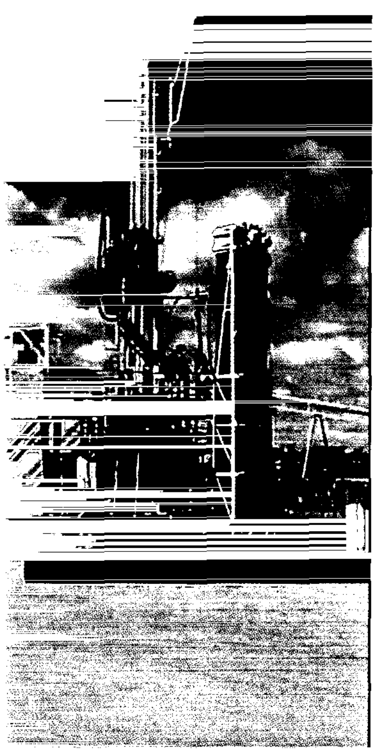
During 2001, we continued our strategy of developing natural gas reserves, primarily in the form of coalbed methane, but also from conventional formations. Our activities continue to focus on opportunities in Australia and the United States, and are centered on our belief that natural gas use will increase substantially in both of these countries over the long term. The importance of natural gas to the overall energy supply mix has been publicly recognized by the governments in both countries. Following is a status report on our activities in each country.

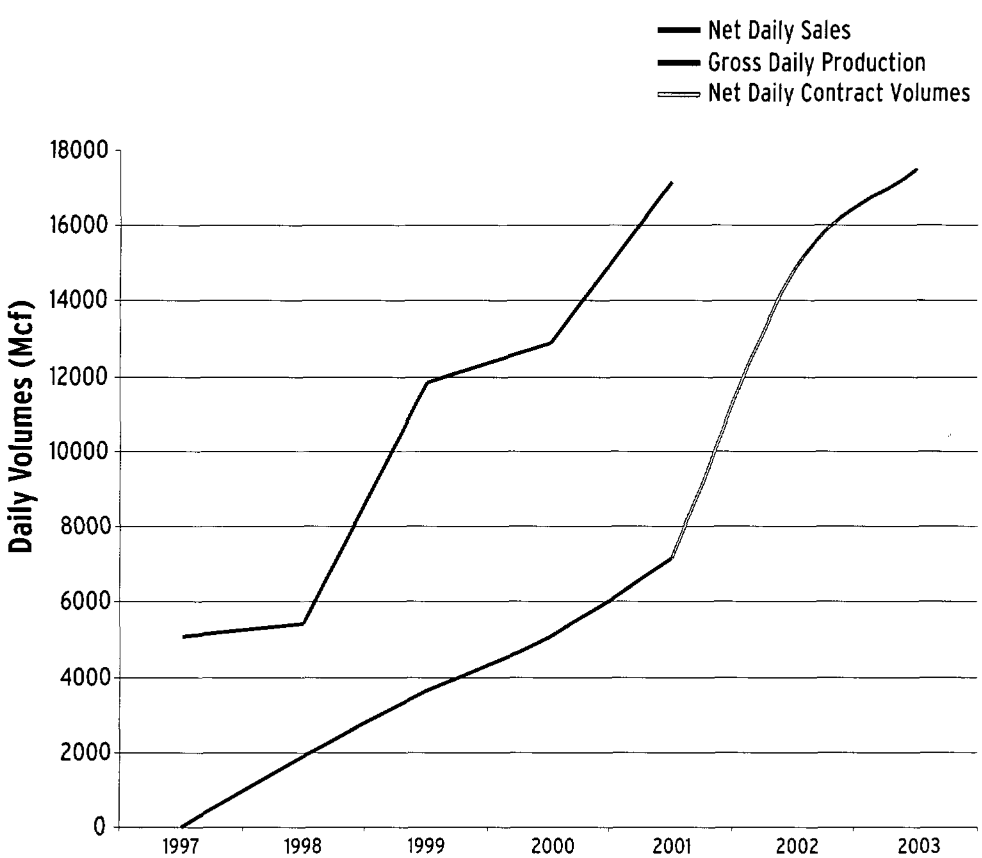
Australia

The Comet Ridge project continues to account for most of our time and capital investment. It represents not only the vast majority of our proved reserves, but a tremendous potential in the probable and possible reserve categories. The reservoir continues to perform as expected, and gross production volumes at the wellhead to the Company's interest have recently reached a high of over 11 million cubic feet per day. We are about halfway through the 20-well development program commenced last year, and expect further production and sales increases as the balance of the wells come on stream.

In a significant recent development, we are pleased to report that we have been granted injunctive relief by the 238th Judicial District Court in Midland County, Texas, with respect to the protracted litigation that has been associated with the Comet Ridge project. The judge in this case has temporarily removed Tri-Star Petroleum Company as operator and named Tipperary successor operator pending the trial presently scheduled for April 29, 2002. The ruling also stated that Tipperary has demonstrated a probable right of recovery in the April trial on the merits. We hope that this will allow us to begin implementation of planned cost-reduction measures. Based upon this ruling, we look forward to a favorable resolution in the near term.

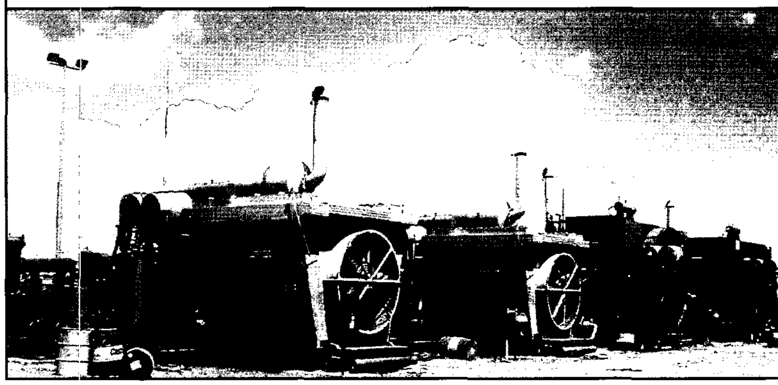
We are obviously very pleased to be operating in Queensland. The government is supportive of the efforts of coalbed methane producers and we see excellent potential in the industrial and power-generation markets. We are currently providing expressions of interest to supply gas for power generation in Townsville, and in July 2002, our contracted sales volumes to ENERGEX Retail Pty Ltd will reach





	Gross Acres	Net Volumes (Bcf)	PV10 (MM$)
Proved	63,000	280	$ 97
Probable	85,000	413	$ 104
Possible(1)	816,000	2,153	$ 92

(1) The majority of the acreage on which the possible reserves have been estimated is on the portion of ATP 526 for which petroleum leases have not been granted.



a new high of approximately 18 million cubic feet per day net to Tipperary's interest. Our relationship with ENERGEX is solid and expected to result in further contracts in the future. During 2001 we also announced a substantial gas contract with QFAL, a group that plans to construct a fertilizer plant near the Comet Ridge project. This contract, which is subject to financing commitments, provides for sales of 260 billion cubic feet of gas over 20 years.

In addition to the Comet Ridge activities, we have drilled five wells on our 100%-owned Authorities to Prospect (ATPs), which are in the vicinity of the Comet Ridge project. Two resulted in dry holes, three warrant further testing, and at this point it is too early to say whether any will be commercial producers. However, as we assume operations on Comet Ridge and accelerate the drilling program, we will curtail activities on our own ATPs. This will allow us to concentrate our efforts and capital investments on drilling that should immediately increase gas production volumes. Given the present opportunities for gas contracts, we feel it is urgent that we increase reserves and deliverability.

United States

You will recall that our initial U.S.-based coalbed methane exploration project was the Hanna Draw prospect in Wyoming. While dewatering operations on the project are continuing, we are disappointed with the results thus far. Due to the time it apparently will take to reduce reservoir pressure sufficiently to determine gas productivity, we transferred 29% of our 49% interest to Williams Production RMT Company, our co-venturer, in return for their agreement to pay costs attributable to our remaining 20% share of five additional wells. We do not currently anticipate any meaningful additional capital investment in this project.

Subsequent to our acquisition of an interest in the Hanna Draw acreage, we made a strategic decision to change courses and assemble our own prospect acreage. The first such effort was the Lay Creek prospect in Moffat County, Colorado, where we acquired 75,000 acres and sold 50% to Koch Exploration in return for $2 million cash and $2 million in carried interest to our account. We recently drilled and completed two coalbed methane tests in the Williams Fork coals. We have analyzed core data, commenced dewatering, and are now preparing to drill four additional pilot wells. We are encouraged by gas content and the fact that we are already producing small amounts of gas. Assuming the five-well pilot pattern is successful, we will continue drilling and attempt to achieve commercial production levels.

Separate from the Lay Creek prospect, we acquired 30,000 additional acres in Moffat County, which we believe to be prospective in conventional reservoirs. We recently transferred 60% of this prospect to an industry partner for approximately $595,000 and their agreement to pay half of the costs of our 40% interest to casing point on the first well. Drilling operations will begin in the near future.

Our most recent leasing activity has been in eastern Colorado, where we have acquired approximately 150,000 net acres. The acquisitions primarily target the fractured Niobrara formations, but other formations will be tested as well. As we have in the northwestern Colorado prospects, we anticipate bringing an industry partner into our acreage position and pursuing exploration in the near term.

The assemblage of these acreage positions and sale of partial interests to industry partners affords us exposure to multiple exploratory prospects at a relatively low cost.

General

As we have reported, the sale of our U.S. assets in 2000 left us with cash flow that is insufficient to cover overhead. Nonetheless, we are steadfast in our belief that this strategy change is best for our long-term interests. We believe that after we assume Comet Ridge operations, the project will generate positive cash flow before capital expenditures. TCW Asset Management Company has funded the majority of development drilling currently underway and is now reviewing the opportunity for further project financing. The remaining $7.5 million of proceeds from our recent rights offering and the projected sale of our remaining producing properties in the United States should provide adequate funding to cover overhead while we attempt to bring the Comet Ridge project, and hopefully one or more domestic projects, into a positive cash flow status.

We expect 2002 to be an exciting year and one in which we mark major accomplishments. As always, we pledge to work toward increasing shareholder value. This has been a difficult task in the short term due to the nature of our projects, but we believe the ultimate value created will be worth the near-term challenges. As a fellow shareholder, I appreciate and share your goals. Thank you for your interest in, and support of, the Company.

David L. Bradshaw

David L. Bradshaw, Chief Executive Officer

officers

David L. Bradshaw	–	President and Chief Executive Officer
Kenneth L. Ancell	–	Executive Vice President-Corporate Development
Jeff T. Obourn	–	Senior Vice President
Lisa S. Wilson	–	Chief Financial Officer
Larry G. Sugano	–	Vice President-Engineering
Roger C. Wiggin	–	Vice President-Geology
Elaine R. Treece	–	Corporate Secretary

directors

David L. Bradshaw	–	Chairman of the Board, President and Chief Executive Officer, Tipperary
Kenneth L. Ancell	–	Executive Vice President-Corporate Development, Tipperary
Eugene I. Davis	–	Chairman and Chief Executive Officer, PIRINATE Consulting Group, L.L.C. Chairman and Chief Executive Officer, RBX Industries, Inc. Director, Coho Energy, Inc.
Douglas Kramer	–	Chairman and Director, Draper and Kramer, Inc. Director, Slough Estates, plc Chairman and Director, Slough Estates USA Inc.
Marshall D. Lees	–	Chief Executive Officer, Slough Estates North America, which includes Slough Estates USA Inc. and Slough Estates Canada Limited Director, Slough Estates, plc Director, Charterhouse Group International, Inc.
Charles T. Maxwell	–	Senior Energy Analyst, Weeden & Co.
D. Leroy Sample	–	Retired Partner, PricewaterhouseCoopers

Australia

Richard A. Barber	–	Director and General Manager, Tipperary Oil & Gas (Australia) Pty Ltd
Neal J. Ambrose	–	Director, Tipperary Oil & Gas (Australia) Pty Ltd

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-KSB

√ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2001

OR

_______ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to __________________

Commission file number 1-7796

TIPPERARY CORPORATION
(Name of small business issuer as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	75-1236955 (I.R.S. employer identification no.)
633 Seventeenth Street, Suite 1550 Denver, Colorado (Address of principal executive offices)	80202 (Zip Code)

Issuer's telephone number (303) 293-9379

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, $.02 par value	American Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: NONE

Indicate by check mark whether the issuer (1) has filed all reports required to be filed by Sections 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes √ No ________

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB☐.

Issuer's revenues for its most recent fiscal year: $3,557,000.

Aggregate market value of common stock held by non-affiliates of the registrant was $25,645,000, based on the closing price of $1.70 per share as of March 6, 2002.

Shares of the registrant's Common Stock outstanding as of March 6, 2002: 38,971,489 shares.

Documents incorporated by reference and the Part of the Form 10-KSB into which the document is incorporated: Definitive Proxy Statement for the 2001 Annual Meeting of Shareholders filed within 120 days after the year ended December 31, 2001 (Part III).

Transitional Small Business Issuer Format Yes _____ No √

PART I

ITEMS 1 AND 2. DESCRIPTION OF BUSINESS AND PROPERTIES

GENERAL

Tipperary Corporation and its subsidiaries ("Tipperary" or the "Company") are principally engaged in the exploration for, and development and production of, natural gas. The Company is primarily focused on coalbed methane properties, with its major producing property located in Queensland, Australia. Tipperary also holds exploration permits in Queensland and is involved in coalbed methane exploration in the United States through projects in Colorado and Wyoming. The Company seeks to increase its reserves through exploration and development projects and possibly through the acquisition of producing properties.

Tipperary was organized as a Texas corporation in January 1967. The Company maintains its principal executive offices at 633 Seventeenth Street, Suite 1550, Denver, Colorado 80202. In addition, the Company leases office space at 952 Echo Lane, Suite 375, Houston, Texas 77024 and at Level 18, 307 Queen Street, Brisbane, Queensland 4000, Australia.

BUSINESS ACTIVITIES

Australia

The Company's activities in Australia are conducted through its 90%-owned Australian subsidiary, Tipperary Oil & Gas (Australia) Pty Ltd ("TOGA"). TOGA owns a 65% undivided interest in the Company's primary producing property located in Queensland, Australia (the "Comet Ridge project"). This project comprises approximately 964,000 acres in the Bowen Basin, including Authority to Prospect ("ATP") 526 covering approximately 686,000 acres and five petroleum leases covering approximately 278,000 acres.

An ATP allows the holder to undertake a range of exploration activities, including geophysical surveys, field mapping and exploratory drilling. Each ATP requires the expenditure of an amount of exploration costs approved by Queensland's Department of Natural Resources and Mines and is subject to renewal every four years. Once a petroleum resource is identified, the holder of an ATP may apply for a petroleum lease, which provides the lessee with the ability to conduct additional exploration, development and production activities.

The most recent renewal of ATP 526 expires on October 31, 2004 and includes expenditure requirements over the four-year term of approximately US$8 million, or approximately US$5.1 million net to the Company's interest. The Company expects to satisfy this spending requirement by conducting exploration activities, including both drilling and seismic surveys over the unevaluated portion of the ATP during the remaining term.

As of March 1, 2002, the Company has drilled 50 wells on the Comet Ridge project. There are 35 producing wells in the Fairview area in the southern portion of ATP 526 and 15 wells in various stages of completion. The Company is selling gas from 19 of the producing wells that are connected to a gathering system which supplies a compressor station feeding into a regulated gas pipeline. The remaining 16 producing wells are either being dewatered or are shut in pending connection. Production from the Comet Ridge wells currently totals in excess of 18 million cubic feet ("MMcf") of gas per day, of which approximately 14 MMcf is being sold. The gas not being sold is either being flared at the wellhead (2 MMcf per day) pending connection to the gathering system or is used in gas compression and dehydration equipment (2 MMcf per day). An additional pipeline from one of the wells to the compressor station was completed in November 2001, allowing the Company to increase its sales from approximately 7 MMcf to 10 MMcf per day.

A 20-well development-drilling program is currently underway on the Comet Ridge project, with approximately half of the wells drilled during 2001 and the remaining wells to be drilled during 2002. Production volumes from two of the wells drilled to date are being sold and volumes from four of the wells are being flared pending connection to the gathering system. The remaining five wells are awaiting production equipment. The Company has funded its share of the drilling costs with financing received under a $17 million borrowing facility with TCW Asset Management Company ("TCW"). The costs of the drilling program and terms of the TCW financing agreement are discussed below under "Item 6., Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 4 to the Consolidated Financial Statements.

While Tipperary is pleased with the results of the development drilling on the Comet Ridge project, the Company believes that the pace of development has not been satisfactory and the costs of the drilling programs and other costs charged to the project have been excessive. The Company filed a lawsuit against the operator in August 1998. Two unaffiliated working interest owners subsequently intervened in the action as plaintiffs. Tipperary and the other plaintiffs allege, among other items, that the defendants have failed to operate the Comet Ridge property in a good and workmanlike manner and have committed various other breaches of the joint operating agreement. The Company recently received a favorable ruling from the judge in the case, in which he entered a temporary injunction to remove Tri-Star as operator and replace it with TOGA effective on March 22, 2002. The judge also indicated that the evidence presented showed a probable right of recovery upon a trial on the merits. The defendants have appealed the injunction issued, which could delay a trial scheduled for April 29, 2002. The Company expects to implement cost reduction measures and to more effectively develop the property as the successor operator. See "Item 3., Legal Proceedings" and Note 12 to the Consolidated Financial Statements.

In addition to the interest in the Comet Ridge property, TOGA holds a 100% interest in other exploration permits granted to TOGA by the Queensland government. These permits cover a total of approximately 1.5 million acres comprising ATPs 655, 675 and 690, which have initial terms expiring on October 31, 2003, February 29, 2004 and November 30, 2004, respectively. TOGA has drilled a total of five exploratory wells on these ATPs, four of which have been completed. Three wells are being tested and evaluated and two wells have been plugged and abandoned. On June 22, 2001, the Company acquired a 25% interest from an unaffiliated third party in ATP 554 in Queensland (approximately 110,000 acres). This interest was acquired under an agreement whereby TOGA is to serve as operator and drill a test well on the ATP in the near term. Several conditions must be met before the Company can be certain of its commitment. If the Company does drill this prospect, it would bear 33.33% of the costs to drill and complete a test well. The Company estimates its net cost to complete the well would be approximately US$700,000.

United States

The Company's assets in the United States currently consist primarily of exploration acreage in Colorado, a producing property in East Texas and an investment in a coalbed methane exploration project in Wyoming.

The Company has a 50% working interest in and serves as operator of the Lay Creek project in Moffat County, Colorado. The project covers various leasehold interests over 81,000 acres. Koch Exploration Company ("Koch"), an unaffiliated third party, holds the remaining 50% working interest under the terms of an agreement to jointly conduct exploratory drilling over this area. Koch paid the Company approximately $2 million for this interest at closing in May 2001 and agreed to pay the Company within 18 months, or by October 2002, approximately $2 million for the Company's share of costs to drill and complete wells on the project acreage. Two exploratory coalbed methane wells have been drilled and completed on this acreage and production testing has recently begun. The Company and Koch are committed to drill three additional wells by June 17, 2002, for which drilling operations are underway.

The Company has established a receivable for the $2 million to be received from Koch for reimbursement of the Lay Creek drilling costs discussed above. The receivable has been reduced by approximately $842,000 for costs incurred to drill and complete the two wells, leaving a balance as of December 31, 2001 of $1,158,000 due the Company on or before October 4, 2002. The Company expects to realize this receivable in full during 2002 through additional drilling that is planned through the third quarter of 2002.

The Company recently sold a 60% interest in a conventional oil and gas exploration project, which is also located in Moffat County, Colorado, to an unaffiliated purchaser for approximately $595,000. The purchaser is expected to drill a test well in the second quarter and will pay one half of the Company's 40% share of drilling costs through casing point.

In addition to its projects in western Colorado, the Company has leased approximately 150,000 acres in eastern Colorado as of December 31, 2001. As it has with its other Colorado projects, the Company will seek industry partners to join in the exploration of these prospective areas.

In July 2001, the Company entered into an agreement with Williams Production RMT Company (fka Barrett Resources), the operator of the Hanna Basin coalbed methane project in Wyoming, to transfer a portion of the Company's interest in the project to Williams. The agreement provides that Williams will pay 100% of the costs to drill and complete five additional test wells on the project. Upon completion of these wells, the Company will assign Williams a net 29% working interest and retain a net 20% working interest in the project. Two of the five test wells have been drilled and the Company expects the remaining three test wells to be drilled mid-2002. While the assignment of the 29% working interest is pending completion of the five test wells, the Company's share of lease operating expenses has already been reduced to 20%. The Company does not expect significant capital investment in this project in the near term and therefore may relinquish acreage if it does not proceed further with the project.

On the Company's West Buna property in east Texas, two development wells were drilled in 2001. Both wells are producing gas and have added approximately 300 Mcf of gas and 30 barrels of oil production per day, net to the Company's interest. The Company also participated in a workover of another well in the West Buna field in late 2001 in an attempt to improve production rates. The Company may sell the West Buna property during 2002 and use the proceeds to fund capital investment in its other exploration and development projects in the United States and Australia.

PRODUCING WELLS AND ACREAGE

The following table sets forth information with respect to the Company's producing wells and acreage as of December 31, 2001:

	Producing wells				Acreage			
	Oil		Gas		Producing		Undeveloped	
State/Country	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Australia(1)	-	-	34	20.77	12,597	7,550	265,736	164,517
Colorado(2)	-	-	-	-	-	-	351,144	266,515
Oklahoma(2)	-	-	-	-	-	-	140	35
Texas(2)	-	-	23	1.95	6,613	660	653	20
Wyoming(2)(3)	-	-	26	1.76	920	105	35,368	17,301
Total	-	-	83	24.48	20,130	8,315	653,041	448,388

(1) Of the 34 producing wells in Australia, 18 were connected to a pipeline system, while gas production from 16 wells was being flared at the wellhead during the de-watering process or were awaiting connection to the gathering system. An additional 15 wells were awaiting completion or equipment installation. The acreage reported in this table includes only that which is covered by a petroleum lease. The Company also holds, either directly or indirectly, ATPs that cover approximately 2.3 million acres. The Comet Ridge project comprises approximately 686,000 acres under ATP 526, in addition to the 278,333 acres that are included in petroleum leases. The Company holds a 25% interest in ATP 554, which covers 110,000 acres and also holds other ATPs that permit it to conduct exploration activities over approximately 1.5 million acres.

(2) The Company's domestic undeveloped leases have various primary terms ranging from five to ten years. The expiration of any leasehold interest or interests would not have a material adverse financial effect on the Company. However, costs associated with unevaluated acreage that expires or is forfeited could result in a non-cash write-down under the full cost method of accounting. See Critical Accounting Policies discussed under "Item 6. Management's Discussion and Analysis of Financial Condition and Results of Operation."

(3) The wells in Wyoming are in the Hanna Basin project and are producing water in an effort to determine whether gas production from this coalbed methane project will be commercially viable. In order to maintain certain acreage held under leases related to this project, the Company is required to participate for its share of costs of a drilling commitment of ten wells to be drilled during the development phase of the project beginning September 1, 2001 and ending August 31, 2002. Options to extend the development phase for three years would require ten wells to be drilled each year. A total of 76 wells will have to be drilled to earn all of the acreage. The Company does not plan to incur further capital costs for this project and therefore will be subjected to the nonconsent provisions of the joint operating agreement and will be required to relinquish acreage to the extent the project is not fully developed.

DRILLING ACTIVITIES

Information concerning the number of gross and net wells drilled by the Company during 2001, the three-month transition period ended December 31, 2000 and in fiscal years 2000, and 1999 is as follows:

	Australia		United States		Total	
	Gross	Net	Gross	Net	Gross	Net
Year ended December 31, 2001						
Wells drilled (productive)	-	-	-	-	-	-
Exploratory[1]	2	2.00	2	1.00	4	3.00
Development	6	3.71	15[2]	.89	21	4.60
Dry holes drilled (exploratory)	2	2.00	-	-	2	2.00
Total Wells Drilled	10	7.71	17	1.89	27	9.60
Three months ended December 31, 2000						
Wells drilled (productive)						
Exploratory[1]	-	-	6[2]	2.94	6	2.94
Development	-	-	-	-	-	-
Total Wells Drilled	-	-	6	2.94	6	2.94
Fiscal year ended September 30, 2000						
Wells drilled (productive)						
Exploratory [1]	-	-	1	.49	1	.49
Development	5	2.97	4	.24	9	3.21
Total Wells Drilled	5	2.97	5	.73	10	3.70
Fiscal year ended September 30, 1999						
Wells drilled (productive)						
Exploratory	-	-	-	-	-	-
Development	5	2.79	3	.01	8	2.80
Total Wells Drilled	5	2.79	3	.01	8	2.80

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(1) Further testing of these coalbed methane wells in Australia and the United States is required in order to determine if they are economically viable.

(2) Two (.33 net) development wells drilled during 2001 are in the West Buna field. The production from these wells is included in sales volumes. Two (.40 net) development wells drilled during 2001 are in the Hanna Basin project in Wyoming and are producing water in an effort to determine the commercial viability of this field. The remaining 11 (.16 net) development wells were drilled in the Powder River basin in Wyoming.

The six exploratory wells drilled during the three-month transition period ended December 31, 2000 are in the Hanna Basin project in Wyoming.

PRODUCTION

The following table summarizes information regarding Tipperary's net gas and oil production for the year ended December 31, 2001, three-month transition period ended December 31, 2000 and for the fiscal years ended September 30, 2000 and 1999.

Australia	Quantities Sold		Average Sales Price		Average
	Gas (Mcf)[1]	Oil (Bbl)	Gas (Mcf)	Oil (Bbl)	Lifting Cost Per Mcf
2001	2,339,000	-	$ 1.11	$ -	$ 0.64
Oct - Dec 2000	466,000	-	$ 1.13	$ -	$ 0.83
Fiscal 2000	1,606,000	-	$ 1.27	$ -	$ 0.87
Fiscal 1999	904,000	-	$ 1.32	$ -	$ 0.96

United States	Quantities Sold		Average Sales Price		Average
	Gas (Mcf)	Oil (Bbl)	Gas (Mcf)	Oil (Bbl)	Lifting Cost Per Mcf [2]
2001	100,000	17,000	$ 4.83	$ 24.10	$ 4.07
Oct-Dec 2000	31,000	3,000	$ 5.75	$ 30.33	$ 1.40
Fiscal 2000	711,000	192,000	$ 2.76	$ 23.63	$ 1.52
Fiscal 1999	1,183,000	352,000	$ 1.68	$ 13.15	$ 1.13

(1) Excludes the Company's share of total volumes produced but not sold from the Comet Ridge project in Queensland, Australia. Production of 986,000 Mcf during the year ending December 31, 2001, 156,000 Mcf during the transition period ended December 31, 2000, 594,000 Mcf during fiscal 2000 and 462,000 Mcf during fiscal 1999 was consumed in operations or flared at the wellhead from wells not connected to the gathering system and in the de-watering process.

(2) Approximately one half of the lifting costs in the United States during 2001 were costs to workover nine wells. In addition, lifting costs include $365,000 associated with the Hanna Basin and Lay Creek projects, which do not have any associated gas sales. If the workover costs and Hanna Basin and Lay Creek costs are excluded, average lifting cost per Mcf would be $0.91.

SIGNIFICANT CUSTOMERS AND DELIVERY COMMITMENTS

The Company is currently selling its gas production in Australia under two contracts with ENERGEX Retail Pty Ltd ("ENERGEX"), an unaffiliated customer. The first contract has delivery requirements of up to approximately 5,500 Mcf of gas per day through December 2003. A second five-year contract, entered into with ENERGEX effective June 1, 2000, currently has delivery requirements of approximately 8,500 Mcf of gas per day and calls for additional gas quantities of up to approximately 15 million cubic feet per day beginning July 1, 2002 through May 2005.

In 2001, the Company entered into a gas sales agreement to supply, upon the satisfaction of certain conditions, up to 260 Bcf of gas to Queensland Fertilizer Assets Limited ("QFAL"). The gas is to be consumed by a fertilizer plant QFAL intends to construct in southeastern Queensland. The 20-year term of this agreement starts in 2004 and would be in addition to the Company's current sales under its two contracts with ENERGEX.

The QFAL agreement provides that QFAL will have financing commitments for construction of its fertilizer plant and that the Company will have the financing to drill and complete enough wells to satisfy its delivery requirements. Construction of QFAL's plant should take approximately two years and would begin approximately six months after QFAL obtains project financing and governmental approval, neither of which can be assured. The Company believes that current and anticipated development drilling programs on the Comet Ridge project will enable it to satisfy these delivery commitments.

In the United States, the Company sells its oil and gas production to several purchasers, generally under short-term contracts. Tipperary had domestic sales in excess of 10% of total U.S. revenues to the oil and gas customers listed below.

	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	1999
Sunoco, Inc.	-	36%	14%	-
BPAmerica Production Co.	77%	39%	22%	23%
Smith Production Inc.	22%	-	-	-
Versado Gas Processors, LLC	-	-	12%	11%
Plains Marketing, LP	-	-	-	10%

Since numerous purchasers compete to purchase both oil and gas from the Company's properties in both the United States and Australia, the Company does not believe that the loss of any single existing purchaser would have a material adverse impact on its ability to sell its production to another purchaser at similar prices. Nonpayment by such purchasers, however, could adversely affect operating results.

PRICING

Oil and natural gas prices are subject to significant fluctuations. Natural gas prices in the United States fluctuate based primarily upon weather patterns and regional supply and demand, and crude oil prices fluctuate based primarily upon worldwide supply and demand. The Company's domestic gas sales have been through contracts whereby the oil and gas is sold at the wellhead. Substantially all of the Company's domestic sales are from the West Buna field. The Company receives a premium for gas sales in the West Buna field as the contract gas price is based on the energy content of gas and liquid volumes being produced.

The Company has used derivatives to hedge risks associated with the volatility of oil and gas prices. None of the Company's production has been hedged since fiscal 2000. See the discussion of hedging activities in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements.

In Australia, the Company's current sales to ENERGEX are under two fixed-price contracts in Australian dollars and adjusted for inflation annually. The average U.S. dollar equivalent price during 2001 for the 5,500 Mcf per day delivered under the first contract was $1.07 per Mcf. Deliveries under the second contract averaged 1,700 Mcf per day during 2001 at a U.S. dollar equivalent price of $1.11 per Mcf. The QFAL contract with a 20-year term beginning in 2004 calls for an initial U.S. dollar equivalent price of approximately $1.02 per Mcf at current exchange rates. After two years, the Company would receive upward adjustments in the price received for gas sales to the extent the price received by QFAL from its sales of the fertlizer urea increase in excess of a specified minimum. Based on current urea prices the U.S. dollar equivalent price received by the Company after two years would be approximately $1.95 per Mcf.

COMPETITION AND OTHER RISKS

The oil and natural gas industry is highly competitive. The Company encounters strong competition from other independent operators and from major oil companies in acquiring properties and in contracting for drilling equipment. Many of these competitors have financial resources and staffs substantially larger than those of the Company. The Company also competes with other companies in all industries in raising capital. Its ability to access the capital markets is largely dependent on the success of its oil and gas exploration activities and the economic environment in which it operates.

This report contains certain statements of future business plans and objectives and statements in Part I and in "Management's Discussion and Analysis of Financial Condition and Results of Operations," which may be considered forward-looking. These forward-looking statements are subject to risks and uncertainties. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. The operations of the Company, both domestically and internationally, are subject to risks including, but not limited to, all of the risks that are encountered in the drilling and completing of wells, along with standard risks of oil and gas operations, uninsured hazards, volatile oil and gas prices, foreign exchange rate risk and uncertain markets and governmental regulation. For a discussion of these and other risks which relate to the forward-looking statements contained herein, please see "Risk Factors" in the Company's Registration Statement on Form S-3, SEC File No. 333-59052, which discussion is incorporated herein by reference, along with other cautionary statements in this report.

PROVED OIL AND GAS RESERVES

Supplementary information concerning the Company's estimated proved oil and gas reserves and discounted future net cash flows applicable thereto is included in Note 14 to the Company's Consolidated Financial Statements herein.

The Company did not file any estimates or reserve reports of the Company's proved domestic net oil or gas reserves with any governmental authority or agency other than the Securities and Exchange Commission during the year ended December 31, 2001.

UNITED STATES REGULATIONS

General. The production, transmission and sale of crude oil and natural gas in the United States is affected by numerous state and federal regulations with respect to allowable well spacing, rates of production, bonding, environmental matters and reporting. Future regulations may change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted. Although oil and gas may currently be sold at unregulated prices, such sales prices have been regulated in the past by the federal government and may be again in the future.

State Regulation. Oil and gas operations are subject to a wide variety of state regulations. Administrative agencies in such jurisdictions may promulgate and enforce rules and regulations relating to virtually all aspects of the oil and gas business.

Environmental Matters. The Company's business activities are subject to federal, state and local environmental laws and regulations. Compliance with these regulations increases the Company's overall cost of doing business. These costs include production expenses primarily related to the disposal of produced water and the management and disposal of other wastes associated with drilling for and production of hydrocarbons. The Company has incurred costs of approximately $25,000, $94,000, $22,000 and $25,000 in 2001, the transition period ended December 31, 2000, fiscal 2000 and 1999, respectively, to comply with environmental regulations. The Company will continue to monitor its environmental compliance. There can be no assurance that environmental laws and regulations will not become more stringent in the future or that the Company will not incur significant costs in the future to comply with these laws and regulations.

AUSTRALIA REGULATIONS

Commonwealth of Australia Regulations. The regulation of the oil and gas industry in Australia is similar to that of the United States, in that regulatory controls are imposed at both the commonwealth (national) and state levels. Specific commonwealth regulations impose environmental, cultural heritage and native title restrictions on accessing resources in Australia. These regulations are in addition to any state level regulations. Native title legislation was enacted in 1993 in order to provide a statutory framework for deciding questions such as where native title exists, who holds native title and the nature of native title which were left unanswered by a 1992 Australian High Court ("Court") decision. The Commonwealth and Queensland State governments have passed amendments to this legislation to clarify uncertainty in relation to the evolving native title legal regime in Australia created by the decision in a 1996 Court case. Each authority to prospect, petroleum lease and pipeline license must be examined individually in order to determine validity and native title claim vulnerability.

State of Queensland Regulations. The regulation of exploration and recovery of oil and gas within Queensland is governed by state-level legislation. This legislation regulates access to the resource, construction of pipelines and the royalties payable. There is also specific legislation governing cultural heritage, native title and environmental issues.

Environmental Matters. Environmental matters are highly regulated at the state level, with most states having in place comprehensive pollution and conservation regulations. In particular, petroleum operations in Queensland must comply with the Environmental Protection Act and any condition requiring compliance with the Australian Petroleum Production and Exploration Association Code of Practice. The Company has not incurred identifiable costs to comply with the foregoing regulations and management believes that any future costs will not be material and will not significantly hinder or delay the Company's plans in Australia. However, there can be no assurance that environmental laws and regulations will not become more stringent in the future or that the Company will not incur significant costs in the future to comply with these laws and regulations.

Australia Crude Oil and Gas Markets. The Australia and Queensland onshore crude oil and gas markets are not regulated. However, a national regulatory framework for the natural gas market in Australia has recently been established (on a state by state basis). The National Gas Access Regime (the "Regime") has been developed by a group of government and oil and gas industry representatives. Among the objectives of the Regime are to provide a process for establishing third party access to natural gas pipelines, to facilitate the development and operation of a national natural gas market, to promote a competitive market for gas in which customers are able to choose their supplier, and to provide a right of access to transmission and distribution networks on fair and reasonable terms and conditions. The Company cannot currently ascertain the impact of the Regime but believes it should benefit the Company.

EMPLOYEES

At December 31, 2001, the Company employed 15 persons on a full-time basis, including its officers. None of the Company's employees are represented by unions. The Company considers its relationship with its employees to be excellent.

ITEM 3. LEGAL PROCEEDINGS

The Company is a plaintiff in a lawsuit filed on August 6, 1998, styled *Tipperary Corporation and Tipperary Oil & Gas (Australia) Pty Ltd v. Tri-Star Petroleum Company*, Cause No. CV42,265, in the District Court of Midland County, Texas involving the Comet Ridge project. By amended petition filed May 1, 2000, Tipperary Oil & Gas Corporation joined the action as a plaintiff, along with the already-named plaintiffs and two unaffiliated non-operating working interest owners who previously intervened in the action as plaintiffs. James H. Butler, Sr., and James H. Butler, Jr., owners of defendant Tri-Star Petroleum Company, were also named as defendants in the amended petition. The Company and the other plaintiffs allege, among other matters, that Tri-Star and/or the individual defendants have failed to operate the properties in a good and workmanlike manner and have committed various other breaches of a joint operating contract, have breached a previous mediation agreement between the parties, have committed certain breaches of fiduciary and other duties owed to the plaintiffs, and have committed fraud in connection with the project. Tri-Star has answered the amended petition, and on December 22, 2000, Tri-Star filed its first amended counterclaim alleging tortious interference with the contracts, with the authority to prospect covering the project and with contractual relationships with vendors; commercial disparagement; foreclosure of operator's lien and alternatively forfeiture of undeveloped acreage; unjust enrichment and declaratory relief. As of February 8, 2001, the court enjoined Tri-Star from asserting any forfeiture claims based upon events prior to that date. On March 11, 2002, the court entered a Writ of Temporary Injunction, and an Amended Writ of Temporary Injunction on March 13, 2002, to enforce the votes of a majority-in-interest of the parties under the joint operating agreement to remove Tri-Star as operator and replace it with TOGA. The orders provided that TOGA take over operations on March 22, 2002. On March 15, 2002, Tri-Star filed a Notice of Accelerated Appeal of the March 11, 2002 Order Granting Injunctive Relief Regarding Removal of Tri-Star Petroleum Company as Operator. The lower court denied Tri-Star's request for a stay of enforcement of the injunctive orders. Tri-Star sought a stay from the Texas Court of Appeals, which was likewise denied. TOGA has assumed operation of the Comet Ridge project under the terms of the orders. An evidentiary hearing relating to the May 2, 1996 Mediation Agreement between the parties and the obligation of the parties to arbitrate audit disputes is presently scheduled to begin on April 3, 2002. A trial on the merits is presently scheduled for April 29, 2002, although the prosecution of an appeal of the injunctive orders may delay the commencement of the trial.

Through December 31, 2001, the Company has made payments totaling approximately $1.1 million into the registry of the court for disputed portions of joint interest billings from Tri-Star. At the appropriate time, the court will determine the disposition of the funds paid into its registry. The funds may be returned to the Company, in whole or in part, or awarded to Tri-Star in whole or in part. If, and to the extent funds are returned, the Company will reduce its full cost pool for recovered capital costs and will record a gain for recovered operating costs. If, and to the extent funds are awarded to Tri-Star, the Company will not record an additional loss.

In 1997, the Company filed a complaint along with ten other plaintiffs in *BTA Oil Producers, et al. v. MDU Resources Group, Inc.* in Stark County Court in the Southwest Judicial District of North Dakota. The plaintiffs include major integrated oil companies (such as ExxonMobil Corporation) and agricultural cooperatives (Cenex Harvest States Cooperatives), as well as independent oil and gas producers such as the Company. The plaintiffs brought the action against the defendants for breach of gas sales contracts and processing agreements, unjust enrichment, implied trust and related business torts. The case concerns the sale by plaintiffs and certain predecessors of natural gas processed at the McKenzie Gas Processing Plant in North Dakota to Koch Hydrocarbons Company. It also concerns the contracts for resale of that gas to MDU Resources Group, Inc. and Williston Basin Interstate Pipeline Company. After the complaint was answered, the defendants moved for summary judgment against the plaintiffs. The trial court has entered two orders deciding the issues in the case. The plaintiffs prevailed on some issues, and the defendants prevailed on other issues. The parties are discussing the form of a judgment to submit to the trial court for entry. The parties anticipate an appeal after the judgment is entered.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's common stock is listed and has been trading on the American Stock Exchange since April 1992. As of March 6, 2002, there were approximately 1,900 holders of record of the Company's common stock. The table below sets forth the high and low closing prices for the common stock of the Company for the periods indicated:

	Year Ended December 31, 2001		Transition Period ended December 31, 2000		Year Ended September 30 2000	
	High	Low	High	Low	High	Low
March 31	$ 3.99	$ 2.05	N/A	N/A	$ 4.06	$ 1.19
June 30	$ 3.80	$ 2.45	N/A	N/A	$ 3.69	$ 2.13
September 30	$ 2.45	$ 1.50	N/A	N/A	$ 4.25	$ 3.25
December 31	$ 2.25	$ 1.30	$ 3.75	$ 3.00	$ 1.63	$ 1.00

The Company has not paid any cash dividends on its common stock and does not expect to pay any dividends in the foreseeable future. The Company intends to retain any earnings to provide funds for operations and expansion of its business.

RECENT SALES OF UNREGISTERED SECURITIES

On December 23, 1999, the Company consummated an equity financing transaction with Slough Estates USA Inc. ("Slough") for the purchase of 6,329,114 shares of the Company's 1999 Series A Convertible Cumulative Preferred Stock for $10,000,000, or $1.58 per share. At closing, Slough converted 2,900,000 shares of the convertible preferred stock into 2,900,000 shares of restricted common stock. Also, at closing, the Company issued Slough warrants for 1,200,000 shares of common stock at an exercise price of $2.00 per share. The warrants may be exercised during an eight-year period beginning December 23, 2001 and ending December 23, 2009. Effective February 29, 2000, Slough converted the remaining shares of preferred stock into 3,429,114 shares of restricted common stock. Proceeds from the $10,000,000 Slough financing was used to substantially reduce the Company's outstanding debt, to fund ongoing coalbed methane exploration and development, and for general corporate purposes.

In February 2000, the Company issued a total of 2,682,316 shares of common stock to five individuals in connection with the acquisition of additional interests in the Comet Ridge coalbed methane project in Queensland, Australia. An additional acquisition of a 1% interest in July 2000 was purchased with the issuance of 300,000 shares to another individual investor. The purchase price of the additional interests acquired totaled approximately $6,211,000 and included cash of $3,300,000 and stock valued at $2,911,000. The cash portion of the combined purchase price was paid using cash on hand of $900,000 and $2,400,000 of proceeds from the sale of 1,518,988 shares of common stock at $1.58 per share and warrants for 288,000 shares of common stock at an exercise price of $2.00 per share to two individual investors. The remaining purchase price of approximately $2,911,000 was paid to the sellers with the issuance of 1,163,328 shares of the Company's common stock at $1.60 per share in February 2000 and 300,000 shares at $3.50 per share in July 2000.

In June 2001, the Company issued restricted common stock to an unaffiliated third party for the acquisition of an additional 2.5% interest in the Comet Ridge coalbed methane project in Queensland, Australia. The purchase price of $1,688,000 was paid to the seller with the issuance of 675,000 common shares, which had a value of $2.50 per share on the date the transaction closed.

The offer and sale of the shares under each of the foregoing transactions were not registered under the Securities Act of 1933 (the "Securities Act"), but rather were made privately by the Company pursuant to the exemption from registration provided by Section 4(2) of the Securities Act. The purchasers of the preferred and common stock under each of the foregoing transactions had full information concerning the business and affairs of the Company and acquired the shares for investment purposes. The certificates representing the securities issued bore a restrictive legend and stop transfer instructions have been entered prohibiting transfer of the securities except in compliance with applicable securities laws.

During 2001 the Company filed Registration Statements on Form S-3, SEC File Nos. 333-56944 and 333-75310, that included 2,138,328 of the shares issued to sellers of interests in the Comet Ridge project and 288,000 shares covered by the warrants issued to two other individuals. Shares of common stock outstanding that remain unregistered from the issuances disclosed above include 1,518,988 issued to two individual investors and 6,329,114 shares issued to Slough. In addition, the warrants held by Slough to acquire 1,200,000 shares of common stock have not been registered.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

GENERAL

The following is a discussion of the Company's financial condition and results of operations. This discussion should be read in conjunction with the Consolidated Financial Statements and the Notes thereto.

This discussion and analysis of financial condition and results of operations, and other sections of this Form 10-KSB, contain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are based on management's beliefs, assumptions, current expectations, estimates and projections about the oil and gas industry, the economy and about the Company itself. Words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or comparable words are intended to identify the forward-looking statements. These statements are not guarantees of future performance and involve numerous risks, uncertainties and assumptions that are difficult to predict with regard to timing, extent, likelihood and degree of occurrence. Therefore, actual results and outcomes may materially differ from what may be expressed or forecasted in the forward-looking statements. Furthermore, the Company undertakes no obligation to update, amend or clarify forward-looking statements, whether as a result of new information, future events or otherwise.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to, changes in the Company's production volumes, worldwide supply and demand which affect commodity prices for oil and gas, competing supplies of gas in Australia, the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and natural gas reserves, risks inherent in the drilling and operation of oil and natural gas wells, future production and development costs, the ability of the Company to obtain financing for its proposed activities, the effect of existing and future laws, governmental regulations and the political and economic climate of the United States and Australia, as well as conditions in the capital markets. For a discussion of these and other risks related to the forward-looking statements contained herein, please see "Risk Factors" in the Company's Registration Statement on Form S-3, SEC File No. 333-59052.

OIL AND GAS RESERVES

At December 31, 2001, estimates of Tipperary's total proved oil and gas reserves were 307,000 barrels and 282 Bcf, respectively. While total equivalent reserve volumes remained relatively flat compared to the volumes reported as of December 31, 2000, the standardized measure of discounted future net cash flows decreased by $7,029,000. Using prices in effect at such time and a discount rate of 10% as prescribed by Securities and Exchange Commission rules, total discounted future after tax net cash flows were estimated to be $77,883,000 as of December 31, 2001, compared to $84,912,000 at December 31, 2000. The decrease was primarily attributable to lower period-end prices in the U.S. at December 31, 2001 compared to December 31, 2000. See the Supplementary Financial Information on Oil and Gas Operations in Note 14 to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES

In response to the Securities and Exchange Commission's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," the Company is disclosing the following as the most critical accounting policies utilized in reporting its financial results.

Oil and Gas Reserves

Estimated reserve quantities and estimated future development costs are used to calculate the rate at which the Company records depreciation, depletion and amortization (DD&A) expense. The process of estimating quantities of proved reserves is inherently uncertain and the estimates of future net cash flows from the Company's proved reserves and the present value of such reserves are based upon various assumptions about future production levels and current prices and costs that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of the Company's reserves and amount of estimated future net cash flows from the estimated oil and gas reserves. The discounted after-tax future net cash flows from the estimated reserve quantities impact the recorded value of the full cost pool as discussed below. If the estimate of proved reserve volumes declines or the estimate of future development costs increases, the DD&A expense the Company records increases, reducing net income. Certain early stage exploratory costs are excluded from costs subject to the DD&A calculation. The Company evaluates these excluded costs quarterly and the costs are added to the DD&A base if we determine the costs will or will not result in commercially productive oil or gas production.

Full Cost Method of Accounting for Oil and Gas Properties

The Company accounts for its oil and gas properties using the full cost method. Under this method, the Company is required to record a permanent impairment provision if the net book value of its oil and gas properties less related deferred taxes exceeds a ceiling value equal to the present value of the future cash inflows from proved reserves, tax effected and discounted at 10%. The ceiling test is computed at the end of each quarter. The oil and gas prices used in calculating future cash inflows are based upon the market price on the last day of the accounting period. Oil and gas prices are generally volatile and if the market prices at a period end date have decreased, the Company may have to record an impairment. A loss may also be generated by the transfer of significant early stage exploratory costs to the oil and gas property cost pool that is subject to the ceiling test. These losses typically occur when significant costs are transferred to the oil and gas property cost pool as a result of an unsuccessful project without commercially productive oil and gas production. The Company reported a non-cash write-down during the fiscal year ended September 30, 1999 related to its domestic oil and gas properties.

The Company's Australian properties are in a separate full cost pool, as required under the full cost method. The prices received for sales in Australia are primarily under long-term contracts with fixed prices, adjusted for inflation. However, while there is no volatility with respect to the price received in Australian dollars, any volatility in the exchange rate affects the U.S. dollar equivalent price received and exposes the Company to a potential recorded loss in value.

The Company does not expect to record any losses attributable to its Australian assets in the near term. In the United States, however, the Company has reserves associated with only one producing property. The sale of this east Texas property, which is anticipated during 2002, could result in a write-down of the Company's United States full cost pool and a resulting loss in the income statement. The Company may also record a loss if costs associated with its Hanna Basin, Lay Creek or other domestic exploration projects are added to depletable costs within the domestic full cost pool without associated oil and gas reserves. While the Company's oil and gas properties are subject to writedowns, a subsequent increase in value due to price increases will not be recorded. Instead, the Company would record a lower DD&A expense since the prior impairment would have reduced the net book value of the full cost pool.

Contingencies

The Company accounts for contingencies in accordance with SFAS No. 5, "Accounting for Contingencies." SFAS No. 5 requires that the Company record an estimated loss from a loss contingency when information available prior to issuance of its financial statements indicates that it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Accounting contingencies require the Company to use its judgment and while the Company believes that its accruals for these matters are adequate, if the actual loss from the loss contingency is significantly different than the estimated loss, the results of operations of the Company will be impacted in the period the contingency is resolved.

In the fiscal year ended September 30, 2000 and in 2001, the Company recorded charges to expense of $557,000 and $900,000, respectively, for prepaid drilling costs that the Company estimated will not be realized as either capital expenditures or cash refunds. These sums were paid to Tri-Star as operator of the Comet Ridge project in Australia, with whom the Company has been in litigation during the last few years. The Company may realize an actual loss in excess of this estimate or it may recover a portion or all of these costs depending on the actions of Tri-Star and the outcome of the litigation. The Company may also record gains or losses upon resolution of the Comet Ridge litigation that are unrelated to these prepaid drilling costs. Through December 31, 2001, the Company has made payments totaling approximately $1.1 million into the registry of the 238th Judicial District Court in Midland County, Texas for disputed portions of joint interest billings from Tri-Star. If these funds are returned, the Company will reduce its full cost pool for recovered capital costs and will record a gain for recovered operating costs. If the funds are awarded to Tri-Star, the Company will not record an additional loss.

The Company does not expect to pay income taxes in the near term. In the United States, the utilization of net operating loss carryforwards will reduce the Company's effective federal tax rate from approximately 35% to approximately 2% in years the Company generates taxable income. The carryforwards total approximately $34 million as of December 31, 2001, and expire over the period from fiscal 2002 through fiscal 2021. The Company has recorded a $15.1 million asset for the future benefit of its carryforwards and other tax benefits. As of December 31, 2001, this asset was completely offset by a valuation allowance based upon management's projection of realizability of the gross deferred tax asset. Fluctuations in industry conditions and trends will require periodic management reviews of the recorded valuation allowance to determine if a decrease in the allowance is appropriate. A decrease in the allowance would result in an income tax benefit and a subsequent decrease in the valuation allowance would decrease net income. The Company has not generated taxable income in Australia and with its loss carryforwards does not expect to generate taxable income in Australia in the near term. See Note 11 to the Consolidated Financial Statements.

Use of Derivatives

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Effective with the adoption of SFAS No. 133, all derivatives are recognized on the balance sheet and measured at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting, the gain or loss on the derivative is either recognized in income along with an offsetting adjustment to the basis of the item being hedged for fair value hedges or deferred in other comprehensive income to the extent the hedge is effective for cash flow hedges. To qualify for hedge accounting, the derivative must qualify as either a fair-value, cash-flow or foreign-currency hedge.

The Company has in past years hedged portions of its crude oil sales primarily through swap agreements with financial institutions based upon prices quoted by the New York Mercantile Exchange ("NYMEX"). Under swap agreements, the Company usually received a floor price but retained 50% of price increases above the floor. During the fiscal years ended September 30, 2000 and 1999, the Company hedged a total of 45,000 barrels (approximately 23%) and 95,000 barrels (approximately 27%) of its oil production. Net receipts (payments) pursuant to the Company's hedging activities for fiscal 2000 and 1999 were ($285,000) and ($200,000), respectively. The Company has not hedged any of its production since March 2000. The Company did not hedge its foreign currency exchange risk during 2001, 2000 or 1999.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 to the Consolidated Financial Statements for recent accounting pronouncements and how the Company anticipates they will impact the Company's financial statements.

LIQUIDITY AND CAPITAL RESOURCES

The Company has used equity and debt financings and sales of producing properties to fund most of its capital expenditures and operations during the last few years. Tipperary has also used these funds to acquire additional interests in the Comet Ridge project in Queensland, Australia.

During 2001, the Company used $4,316,000 of cash in operating activities and invested cash of $17,465,000 in capital expenditures and other investing activities. The Company received proceeds of $2,782,000 from the sale of oil and gas assets. The operations and capital investments were funded with net proceeds of $26,835,000 of debt and equity financing.

In the fourth quarter of 2001, the Company received approximately $25,575,000 from the issuance of 13,823,902 shares of its common stock through a shareholder rights offering. Following the offering, there were 38,971,489 total outstanding shares. Costs related to the offering totaling $610,000 were recorded as a reduction of paid in capital. Slough Estates USA Inc. ("Slough"), the Company's largest (62%) shareholder, participated in the rights offering, acquiring 78% of the shares issued and increasing its ownership percentage from 52% to 62%.

In June 2001, the Company issued 675,000 shares to an individual in exchange for a 2.5% interest in the Comet Ridge project in Australia. The stock was valued at $2.50 per share at closing for a purchase price of approximately $1,688,000.

In 2001, the Company issued to Slough 385,821 shares of TOGA stock valued at $1,074,000 in exchange for Slough's cancellation of its contractual payment right to a portion of the Company's revenues from the Comet Ridge project. Slough had received this contractual payment right in fiscal 1999 in connection with its project-financing loan to the Company for the Comet Ridge project eight-well drilling program.

Debt financings during 2001 included $12,000,000 received from TCW Asset Management ("TCW") and $12,500,000 from Slough. The loans from Slough included $2,500,000 for the purchase of a drilling rig to be used in Australia and $10,000,000 in advances used for other capital expenditures and operations. The TCW loan advances were used to repay a Comet Ridge project-financing loan from Slough of $4,406,000, fund TCW-approved drilling costs of $6,580,000 and for restricted working capital of $1,014,000. The Company used $17,500,000 of the proceeds from the rights offering to repay Slough all of the loans advanced for general corporate purposes (the $7,500,000 balance as of December 31, 2000 and $10,000,000 advanced during 2001). In 2001, the Company made principal payments of $75,000 to Slough against the loan for $2.5 million and $11,000 was paid to TCW under the Credit Agreement. Deferred financings costs, which are being amortized over the life of the loan, totaled $1,056,000 as of December 31, 2001 and included $783,000 incurred during 2001 and $273,000 of costs incurred prior to 2001.

The TCW loans were made under a credit agreement that provides a borrowing facility of up to $17 million ("Credit Agreement"). The senior secured promissory notes bear interest at the rate of 10% per annum and are payable quarterly. TCW also receives a 6% overriding royalty from the Company's gross project revenues. Upon payment of the loan in full, TCW has the option to sell this royalty interest to Tipperary at the net present value of the royalty's share of future net revenues from the then proved reserves, discounted at a rate of 15% per annum. The estimated value of $6,843,000 attributed to TCW's royalty interest was recorded as a deferred financing cost and resulted in a decrease in the book value of oil and gas properties. Also, Tipperary has the right to purchase the interest from TCW when both the loan has been repaid in full and TCW has achieved a 15% internal rate of return on its investment. The royalty payments to TCW are estimated to total $1.1 million over the next three years and $33 million over the life of the project if the royalty is not otherwise terminated. Principal payments on the TCW financing are due quarterly in an amount equal to the greater of a percentage of cash flow as defined, or a scheduled minimum principal payment. The scheduled minimum principal payments begin March 2003 and will be equal to 5% of the unpaid principal balance, increasing to 9% in March 2004 and 10% in March 2005. The outstanding principal balance on the notes is due and payable in full on March 30, 2006. See Note 10 to the Consolidated Financial Statements. If the Company fails to make principal payments as required by the Credit Agreement, TCW may require all obligations to be immediately due and payable. The Credit Agreement also requires that TOGA maintain working capital of at least $1,000,000. TCW has recently extended the funding expiry date from December 31, 2001 to April 30, 2002 and the Company anticipates borrowing the remaining $5 million in April for further development of the Comet Ridge project.

At December 31, 2001, the only remaining debt due Slough was the unpaid principal balance of the $2.5 million note payable for the rig financing. The loan balance at December 31, 2001 was $2,425,000 and included a current portion of $760,000 for principal payments the Company estimates that it will pay Slough during 2002. Principal payments are due monthly for rents received from the drilling contractor during the month. The loan bears interest at a rate of 10% per annum payable monthly and the note matures on July 31, 2003.

The Company's 90%-owned Australian subsidiary, TOGA, acquired the drilling rig ("Soilmec rig") and related equipment from a manufacturer in Italy for a total cost of approximately $2.7 million. TOGA acquired the Soilmec rig because it could be used by an unrelated drilling contractor in Queensland, Australia to drill wells on the Comet Ridge project under a turnkey drilling contract that would provide for accelerated drilling at a lower cost. TOGA leased the drilling rig to the contractor ("Lessee") under the terms of an agreement that provides that the Lessee use the rig to drill on the Comet Ridge project and TOGA's other ATPs. To the extent the rig is not being used for TOGA's drilling activities, it may, with TOGA's consent, be used by the Lessee to drill wells for others. The lease payments are structured to be due and payable with the drilling of each well. No interest or finance charge accrues on the lease, but the Company benefits from reduced costs to drill each well on the Comet Ridge project or its other ATPs. In the case of drilling on the Comet Ridge project, the Company's co-owners also benefit from their proportionate share of the cost reduction. The lessee also received a two-year option to buy the rig and related equipment at TOGA's net cost remaining after lease payments.

During 2001, the Soilmec rig was used to drill two wells in the 20-well drilling program currently underway on the Comet Ridge project, two wells on the Company's 100% owned ATP and one well for a third party. The Company received rents during 2001 totaling $75,000 and an additional $80,000 in early 2002, which were used for principal payments to Slough. The Company expects this rig to be used to drill additional wells on the Comet Ridge project during 2002.

The Company has been in litigation with the operator of the Comet Ridge project, Tri-Star Petroleum ("Tri-Star") over cost and other operational issues and was recently granted injunctive relief by the 238th Judicial District Court in Midland County, Texas, temporarily removing Tri-Star as operator and naming TOGA as successor operator pending a trial scheduled for April 29, 2002. The trial date may be delayed by an appeal of the injunctive orders filed by Tri-Star on March 15, 2002. As operator, the Company intends to implement cost-reduction measures, including the reduction of drilling and operating costs.

Through December 31, 2001, the Company has made payments totaling approximately $1.1 million into the registry of the court for disputed portions of joint interest billings from Tri-Star. At the appropriate time, the court will determine the disposition of the funds paid into its registry. The funds may be returned to the Company, in whole or in part, or awarded to Tri-Star in whole or in part. If, and to the extent funds are returned, the Company will reduce its full cost pool for recovered capital costs and will record a gain for recovered operating costs. If, and to the extent funds are awarded to Tri-Star, the Company will not record an additional loss.

The Company's total capital expenditures in 2001 of $20,219,000 included cash investments totaling $17,457,000 and non-cash investments of $2,762,000. Additions to property, plant, and equipment in Australia totaled $12,725,000 and included capital costs totaling $8,946,000 related to its Comet Ridge project and approximately $2,717,000 to purchase the Soilmec drilling rig discussed previously. In addition, TOGA spent $1,062,000 in exploration costs on its other ATP's.

In the United States, total capital expenditures were $7,494,000. The Company invested $5,202,000 in acreage and other costs related to exploration projects in Colorado. The Company drilled two development wells on its West Buna properties in east Texas at a cost of $833,000. These wells were previously included in the Company's proved undeveloped reserves. Exploration costs incurred during 2001 of $1,173,000 included $729,000 of drilling costs on the Lay Creek project in Colorado and approximately $444,000 invested in the Hanna Basin project in Wyoming. The Company capitalized $286,000 of interest expense associated with its unevaluated properties. During 2001, the Company received $739,000 from Koch Exploration Company for reimbursement of the Lay Creek drilling costs incurred. The Company also received $2,043,000 from Koch as consideration for the 50% interest in the Lay Creek project.

Transition Period Ended December 30, 2000

During the three-month transition period, the Company realized $781,000 in cash flow from operations, used $578,000 for financing activities and invested $4,521,000 in capital expenditures. The majority of these expenditures were for drilling costs in the Hanna Basin exploration project in Wyoming and for undeveloped acreage acquisitions in Colorado. Just under $2 million was invested for development costs of the Comet Ridge project and for Tipperary's separate exploration activities on its 100%-owned ATPs in Queensland, Australia.

Financing activities included a $1,000,000 advance from Slough, which increased the total corporate loan to $7,500,000. The remaining debt at December 31, 2000, was also due Slough in the form of a project-financing loan of $4,406,000, which was used to finance the Company's share of an eight-well drilling program on the Comet Ridge project during fiscal 1999 and 2000.

Fiscal Year Ended September 30, 2000

During fiscal 2000, financing transactions provided cash inflows of approximately $14,000,000. Total borrowings of $1,585,000 were received from Slough in connection with the December 1998 Comet Ridge project financing loan. Slough also provided equity proceeds of $10,000,000 in connection with a transaction that closed on December 23, 1999, and included $1,200,000 of value assigned to warrants Slough received to acquire 1,200,000 shares of common stock at $2.00 per share. See Note 2 to the Consolidated Financial Statements. The Company incurred costs of $111,000 related to this equity transaction. Tipperary also received $2,400,000 from the sale of stock and issuance of warrants to two individual investors in connection with financing the acquisition of additional interests in the Comet Ridge project. Net of expenses of sale, the Company received approximately $17,000,000 from the sale of conventional oil and gas properties in the U.S. during the fiscal year ended September 30, 2000. See Note 3 to the Consolidated Financial Statements.

During fiscal 2000, Tipperary used proceeds of $4,000,000 from the Slough financing transaction to reduce bank debt from $11,800,000 to $7,800,000 and then eliminated the remaining bank debt with funds from the sale of domestic oil and gas assets. The Company paid Slough a $79,000 dividend on the convertible preferred stock it held prior to conversion into common stock on February 29, 2000. Tipperary also made principal payments to Slough of $238,000 under the Comet Ridge financing facility. See Note 2 to the Consolidated Financial Statements.

Domestic capital expenditures totaled $2.3 million dollars during fiscal 2000, of which approximately $1,300,000 was expended for acquisition and drilling costs of the Hanna Basin project. The Company incurred approximately $400,000 in acquisition costs for undeveloped acreage in Colorado. The remainder of the total capital expenditures was incurred in connection with various other oil and gas development projects, including activities in the West Buna area in east Texas, and for other corporate expenditures.

During the fiscal year ended September 30, 2000, capital expenditures in Australia included the acquisition of additional interests in the Comet Ridge project for approximately $3,300,000 in cash and 1,463,000 shares of the Company's common stock valued at $2,911,000. Other capital expenditures in Australia included approximately $1.4 million of drilling and completion costs associated with an eight-well drilling program on the Comet Ridge project, which began in fiscal 1999, and $1.3 million of drilling costs for a seven-well drilling program commenced during 2000. Tipperary spent an additional $1.4 million for other ongoing capital expenditures on the Comet Ridge project and approximately $500,000 for initial exploration activities on two of its own ATPs, including the commencement of drilling of one well each on ATP 655 and ATP 675.

Fiscal Year Ended September 30, 1999

During fiscal 1999, the Company received proceeds of $10,872,000 from debt and equity financing provided by and asset sales to Slough. A portion of the funding was used to reduce bank debt by $4.7 million to $11.8 million. Remaining proceeds funded capital expenditures of approximately $6.2 million in Australia and in the United States. Expenditures in Australia totaled $5.6 million and included $2.2 million expended for the eight-well drilling program in the Comet Ridge area and $900,000 for inventory and the construction of gathering facilities. Tipperary incurred

$2.5 million for other development drilling and exploration activities including seismic data gathering operations. The remaining capital expenditures of $698,000 related primarily to domestic oil and gas operations.

Exploration and Development Drilling Commitments

The Company's anticipated capital expenditures during 2002 total approximately $13 million. In Australia, the Company expects to incur capital costs of $10 million, of which $6 million will be for development drilling and for equipment and facilities required to gather anticipated gas production volumes, and $4 million will be for exploration activities on the ATP. The Company plans to incur $1.5 million for its net share of the costs to drill up to 10 wells in its Lay Creek project and to incur approximately $1.5 million on its remaining exploration and development projects in Australia and the United States.

The Company anticipates that cash on hand and anticipated borrowings of $5 million under the TCW Credit Agreement will fund operations and capital expenditures through 2002. In order to fund any capital expenditures in 2002 in excess of these cash resources and to fund capital expenditures beyond 2002, the Company will require alternative sources of capital. Additional sources of funding are expected to include additional debt financings and asset sales. The Company will seek debt financing for further development of the Comet Ridge project and expects sales of domestic assets to provide funding for other capital asset acquisitions or expenditures. The Company plans to sell its interest in the West Buna field in east Texas during 2002 and will continue to seek industry partners in domestic exploration projects. With the sale of interests in its prospective acreage, the Company expects to generate cash to reduce its investment in individual projects. However, in the event that sufficient funding cannot be obtained, the Company will be required to curtail planned expenditures and may have to sell additional acreage and/or relinquish acreage.

RESULTS OF OPERATIONS

Comparison of Calendar Year Ended December 31, 2001 and Fiscal Year Ended September 30, 2000

	Year Ended			
	December 31 2001	September 30 2000	Increase (Decrease)	% Increase (% Decrease)
Worldwide operations:				
Operating revenue	$ 3,557,000	$ 8,624,000	$ (5,067,000)	(59%)
Gas volumes (Mcf)	2,440,000	2,317,000	123,000	5%
Oil volumes (Bbls)	17,000	192,000	(175,000)	(91%)
Average gas price per Mcf	$ 1.27	$ 1.72	$ (0.45)	(26%)
Average oil price per Bbl	$ 24.10	$ 23.63	$ 0.47	2%
Operating expense	$ 2,218,000	$ 4,233,000	$ (2,015,000)	(48%)
Average lifting cost per Mcf equivalent ("Mcfe")(1)	$ 0.92	$ 1.22	$ (0.30)	(25%)
General and administrative	$ 4,257,000	$ 3,732,000	$ 525,000	14%
Depreciation, depletion and amortization ("DD&A")	$ 1,017,000	$ 1,971,000	$ (954,000)	(48%)
DD&A rate per Mcfe volumes sold	$ 0.40	$ 0.57	$ (0.17)	(30%)
Interest expense	$ 2,848,000	$ 1,662,000	$ 1,186,000	71%
Income tax expense (benefit)	$ (1,000)	$ 1,573,000	$ (1,574,000)	(100%)

	Year Ended December 31 2001	Year Ended September 30 2000	Increase (Decrease)	% Increase (% Decrease)
Domestic operations:				
Operating revenue	$ 911,000	$ 6,591,000	$ (5,680,000)	(86%)
Gas volumes (Mcf)	101,000	711,000	(610,000)	(86%)
Oil volumes (Bbls)	17,000	192,000	(175,000)	(91%)
Average gas price per Mcf	$ 4.83	$ 2.76	$ 2.07	75%
Average oil price per Bbl	$ 24.10	$ 23.63	$ 0.47	2%
Operating expense	$ 710,000	$ 2,828,000	$ (2,118,000)	(75%)
Average lifting cost per Mcfe(1)	$ 4.07	$ 1.52	$ 2.55	168%
DD&A	$ 252,000	$ 1,286,000	$ (1,034,000)	(80%)
DD&A rate per Mcfe volumes sold	$ 1.24	$ 0.69	$ 0.55	80%
Australia operations:				
Operating revenue	$ 2,646,000	$ 2,033,000	$ 613,000	30%
Gas volumes (Mcf)	2,339,000	1,606,000	733,000	46%
Average gas price per Mcf	$ 1.11	$ 1.27	$ (0.16)	(13%)
Operating expense	$ 1,508,000	$ 1,405,000	$ 103,000	7%
Average lifting cost per Mcf	$ 0.64	$ 0.87	$ (0.23)	(26%)
DD&A	$ 765,000	$ 685,000	$ 80,000	12%
DD&A rate per Mcf volumes sold	$ 0.33	$ 0.43	$ (0.10)	(23%)

(1) Calculation excludes certain refunds of prior year costs that were included in operating expenses, but which were unrelated to oil and gas production.

The Company incurred a net loss of $7,176,000 in 2001 compared to net income of $43,000 in fiscal 2000. The loss in 2001 resulted primarily from reduced revenues as a result of the sale of most of the Company's U.S. oil and gas properties at the end of fiscal 2000. Fiscal 2000 also benefited from a $4,837,000 gain resulting from the property sales.

Revenues and Volumes

The sale of a majority of the U.S. oil and gas assets during 2000 caused significant reductions in revenues and domestic oil volumes. While gas volumes in the U.S. decreased significantly due to the property sales, gas volumes sold in Australia increased 46% due to increased gas sales from existing wells and also from new wells drilled and connected to the gathering system since September 30, 2000. Gas revenues in Australia, however, increased by only 30% due to a 6% decline in the value of the Australian dollar against the U.S. dollar.

In natural gas production operations, joint owners sometime sell more or less than the production volumes to which they are entitled based on their revenue ownership interest. The joint operating agreement includes gas balancing provisions to govern production allocations in this situation. The Company records a natural gas imbalance in other liabilities if its excess takes of natural gas exceed its remaining proved reserves for the property. As of December 31, 2001, the Company had taken and sold more than its share of natural gas volumes produced from the Comet Ridge project, and was overproduced by approximately 684,000 Mcf. Based on the average price of $1.11 per Mcf received during 2001 from these sales, this represents $760,000 in gas revenues. No liability has been recorded for the excess volumes taken as they do not exceed the Company's share of remaining proved reserves. Under the terms of the gas balancing agreement, the Company may be required to reduce the monthly volumes it delivers by up to 50% in order to enable underproduced parties to take more than their share of the gas and cure the imbalance.

While the U.S. property sales caused a significant decrease in revenue from domestic operations, in the remaining West Buna field, oil and gas sales increased to $925,000 from $677,000. Prices received from these gas sales increased 26% to $4.65 per Mcf from $3.69 per Mcf. Average oil prices decreased 7% to $24.19 per barrel from $26.02 per barrel. The increase in oil and gas volumes of 42% and 3%, respectively, were a result of two new wells drilled and completed in 2001.

Expenses and Foreign Exchange Gains/Losses

Worldwide and domestic operating expenses decreased significantly due to the U.S. property sales. While operating expenses in Australia increased 7% with increasing sales volumes, operating expense per Mcf in Australia decreased 26% because of increasing sales volumes and the decreasing Australian dollar exchange rate.

Operating expenses for the West Buna field increased to $463,000 or $2.17 per equivalent Mcf from $168,000 or $0.98 per equivalent Mcf due to significant workover costs during 2001. Overall domestic operating expense per Mcfe was also increased significantly by $365,000 in lifting costs in the Hanna Basin and Lay Creek projects, which do not have associated gas sales.

General and administrative expenses for 2001 increased 14% when compared to fiscal 2000 due to the loss of overhead recoveries resulting from the U.S. property sales as well as from increased legal expense.

Domestic DD&A expense decreased 80% largely due to decreased sales volumes in the U.S. after the property sales. In Australia, DD&A expense increased 12% due to increasing sales volumes.

In the fourth quarter of 2001 and fiscal 2000, the Company recorded an impairment of prepaid drilling costs of $900,000 and $557,000, respectively, because it was unable to obtain assurance from the operator that either the related work would be completed in the near term or the payments would be refunded.

Interest expense increased to $2,848,000 from $1,662,000, primarily due to a significant increase in long-term debt outstanding for most of 2001. The Company retired $17.5 million in debt in December 2001.

Foreign currency exchange losses were $5,000 in calendar year 2001 compared to a loss of $166,000 in calendar year 2000 because the equivalent U.S. dollar value of the Australian dollar decreased during fiscal 2000 and remained relatively stable during 2001.

The Company recorded a benefit of $1,000 in 2001 due to a state income tax refund. In fiscal 2000, deferred income tax expense of $1,573,000 resulted from a non-cash write-off of the deferred tax asset.

Comparison of Transition Period Ended December 31, 2000 to the Quarter Ended December 31, 1999

	Three Months Ended December 31 2000	Three Months Ended December 31 1999	Increase (Decrease)	% Increase (% Decrease)
Worldwide operations:				
Operating revenue	$ 864,000	$ 2,919,000	$ (2,055,000)	(70%)
Gas volumes (Mcf)	497,000	595,000	(98,000)	(16%)
Oil volumes (Bbls)	3,000	83,000	(80,000)	(96%)
Average gas price per Mcf	$ 1.41	$ 1.82	$ (0.41)	(23%)
Average oil price per Bbl	$ 30.33	$ 21.52	$ 8.81	41%
Operating expense	$ 442,000	$ 1,329,000	$ (887,000)	(67%)
Average lifting cost per Mcf equivalent ("Mcfe")(1)	$ 0.88	$ 1.24	(0.36)	(29%)
General and administrative	$ 1,170,000	$ 669,000	$ 501,000	75%
Depreciation, depletion and amortization ("DD&A")	$ 225,000	$ 742,000	$ (517,000)	(70%)
DD&A rate per Mcfe volumes sold	$ 0.44	$ 0.68	$ (0.24)	(35%)
Interest expense	$ 302,000	$ 544,000	$ (242,000)	(44%)
Income tax expense (benefit)	$ -	$ -	$ -	0%

	Three Months Ended December 31 2000	Three Months Ended December 31 1999	Increase (Decrease)	% Increase (% Decrease)
Domestic operations:				
Operating revenue	$ 339,000	$ 2,497,000	$ (2,158,000)	(86%)
Gas volumes (Mcf)	31,000	279,000	(248,000)	(89%)
Oil volumes (Bbls)	3,000	83,000	(80,000)	(96%)
Average gas price per Mcf	$ 5.75	$ 2.38	$ 3.37	142%
Average oil price per Bbl	$ 30.33	$ 21.52	$ 8.81	41%
Operating expense	$ 57,000	$ 990,000	$ (933,000)	(94%)
Average lifting cost per Mcfe(1)	$ 1.40	$ 1.31	$ 0.09	7%
DD&A	$ 78,000	$ 565,000	$ (487,000)	(86%)
DD&A rate per Mcfe volumes sold	$ 1.59	$ 0.73	$ 0.86	118%
Australia operations:				
Operating revenue	$ 525,000	$ 422,000	$ 103,000	24%
Gas volumes (Mcf)	466,000	316,000	150,000	47%
Average gas price per Mcf	$ 1.13	$ 1.34	$ (0.21)	(16%)
Operating expense	$ 385,000	$ 339,000	$ 46,000	14%
Average lifting cost per Mcf	$ 0.83	$ 1.07	$ (0.24)	(22%)
DD&A	$ 147,000	$ 177,000	$ (30,000)	(17%)
DD&A rate per Mcf volumes sold	$ 0.32	$ 0.56	$ (0.24)	(43%)

(1) Calculation excludes certain refunds of prior year costs that were included in operating expenses, but which were unrelated to oil and gas production.

The Company incurred a net loss of $1,120,000 in the three months ended December 31, 2000 compared to a net loss of $306,000 in the three months ended December 31, 1999. The increased loss resulted from the sale of most of the Company's U.S. oil and gas properties during fiscal 2000.

Revenues and Volumes

The Company experienced significant reductions in revenues and oil volumes due to the sale of most of the Company's U.S. properties in fiscal 2000. While gas volumes in the U.S. decreased significantly due to the property sales, gas volumes sold in Australia increased 47% due to increased gas sales from existing wells and from new wells drilled during 2000. Gas revenues in Australia, however, increased by only 24% because of a 17% decline in the value of the Australian dollar against the U.S. dollar.

The most meaningful comparison for domestic operations can be made excluding properties that have been sold. In the remaining West Buna field, oil and gas sales increased to $295,000 from $217,000. Prices received from these gas sales increased 105% to $6.02 per Mcf from $2.93 per Mcf. Average oil prices increased 34% to $30.15 per barrel from $22.48 per barrel. Oil and gas volumes sold each declined approximately 20% as a result of naturally declining production rates.

Expenses and Foreign Exchange Gains/Losses

Worldwide and domestic operating expenses decreased significantly due to the U.S. property sales. While operating expenses in Australia increased 14% with increasing sales volumes, operating expenses per Mcf in Australia decreased 22% due to increasing sales volumes.

Operating expenses for the West Buna field increased to $70,000 or $1.33 per equivalent Mcf from $62,000 or $0.94 per equivalent Mcf due to an increase in production taxes resulting from higher revenues.

General and administrative expenses increased 75% with increases in costs of ongoing litigation regarding the Comet Ridge project and the loss of overhead reimbursements upon the sale of most of the Company's U.S. properties.

Domestic DD&A expense decreased 86% largely due to decreased sales volumes in the U.S. after the property sales. In Australia, both DD&A expense and the DD&A rate decreased as a result of approximately doubling proved Australian reserves.

The decrease in interest expense was primarily due to a decrease in long-term debt outstanding.

Foreign currency exchange gains were $32,000 in the 2000 period compared to a loss of $1,000 in the 1999 three-month period.

Comparison of the Fiscal Years Ended September 30, 2000 and 1999

	Year Ended			
	September 30 2000	September 30 1999	Increase (Decrease)	% Increase (% Decrease)
Worldwide operations:				
Operating revenue	$ 8,624,000	$ 7,921,000	703,000	9%
Gas volumes (Mcf)	2,317,000	2,087,000	230,000	11%
Oil volumes (Bbls)	192,000	352,000	(160,000)	(45%)
Average gas price per Mcf	$ 1.72	$ 1.52	$ 0.20	13%
Average oil price per Bbl	$ 23.63	$ 13.15	$ 10.48	80%
Operating expense	$ 4,233,000	$ 4,587,000	$ (354,000)	(8%)
Average lifting cost per Mcf equivalent ("Mcfe")	$ 1.22	$ 1.09	$ 0.13	12%
General and administrative	$ 3,732,000	$ 2,262,000	$ 1,470,000	65%
Depreciation, depletion and amortization ("DD&A")	$ 1,971,000	$ 3,154,000	$ (1,183,000)	(38%)
DD&A rate per Mcfe volumes sold	$ 0.57	$ 0.75	$ (0.18)	(24%)
Interest expense	$ 1,662,000	$ 1,633,000	$ 29,000	2%
Income tax expense (benefit)	$ 1,573,000	$ -	$ 1,573,000	N/A

Domestic operations:

Operating revenue	$ 6,591,000	$ 6,730,000	$ (139,000)	(2%)
Gas volumes (Mcf)	711,000	1,183,000	(472,000)	(40%)
Oil volumes (Bbls)	192,000	352,000	(160,000)	(45%)
Average gas price per Mcf	$ 2.76	$ 1.68	$ 1.08	64%
Average oil price per Bbl	$ 23.63	$ 13.15	$ 10.48	80%
Operating expense	$ 2,828,000	$ 3,717,000	$ (889,000)	(24%)
Average lifting cost per Mcfe	$ 1.52	$ 1.13	$ 0.39	35%
DD&A	$ 1,286,000	$ 2,621,000	$ (1,335,000)	(51%)
DD&A rate per Mcf volumes sold	$ 0.69	$ 0.80	$ (0.11)	(14%)

Australia operations:

Operating revenue	$ 2,033,000	$ 1,191,000	$ 842,000	71%
Gas volumes (Mcf)	1,606,000	904,000	702,000	78%
Average gas price per Mcf	$ 1.27	$ 1.32	$ (0.05)	(4%)
Operating expense	$ 1,405,000	$ 870,000	$ 535,000	61%
Average lifting cost per Mcf	$ 0.87	$ 0.96	$ (0.09)	(9%)
DD&A	$ 685,000	$ 533,000	$ 152,000	29%
DD&A rate per Mcf volumes sold	$ 0.43	$ 0.59	$ (0.16)	(27%)

The Company reported net income of $43,000 in fiscal year ended September 30, 2000 versus a net loss of $9,295,000 in fiscal year ended September 30, 1999. The income in fiscal 2000 included a $4,837,000 gain on domestic property sales, a $1,573,000 non-cash write-down of the Company's deferred tax asset, and a $557,000 non-cash impairment of prepaid drilling costs. The loss in fiscal 1999 included a $5,727,000 non-cash write-down of domestic oil and gas properties.

Revenues and Volumes

Gas sales in Australia from the Company's interest in the Comet Ridge project increased 71% due to increasing sales volumes. Volumes sold in Australia increased 78% from new wells being drilled and connected to the Comet Ridge gathering system. The U.S. dollar equivalent gas prices received decreased 4% due to a decrease in the value of the Australian dollar against the U.S. dollar.

While volumes sold from the Company's U.S. properties decreased significantly due to producing property sales, domestic revenues declined only 2% due to substantial increases in oil and gas prices.

Expenses and Foreign Exchange Gains/Losses

Overall operating expenses decreased 8%. Operating expenses attributable to the Comet Ridge project increased 61%. While the Company reported higher operating expenses in Australia, the average lifting cost for the Comet Ridge project decreased 9% due to increased sales volumes.

Operating expenses attributable to domestic properties decreased 24% due to the property sales.

General and administrative expenses increased 65%, primarily due to costs associated with litigation regarding the Comet Ridge project.

Overall DD&A expense decreased 38%. The decrease was attributable to reduced capital costs in the Company's full cost pool resulting from domestic asset sales. Increased sales from the Comet Ridge project caused a 29% increase in DD&A expense for Australia.

At September 30, 2000, the Company recorded a $557,000 impairment of prepaid drilling costs, because it was unable to obtain assurance from the operator that either the work would be completed in the near term or the payments would be refunded.

Foreign currency exchange losses of $166,000 in fiscal 2000 resulted from the decrease in the U.S. dollar value of revenues received in Australian currency for coalbed methane gas sales from the Comet Ridge project. Gains of $19,000 were recorded in fiscal 1999.

Deferred income tax expense of $1,573,000 in fiscal 2000 resulted from a write-off of the net deferred tax asset.

ITEM 7. FINANCIAL STATEMENTS

The following financial statements appear on pages 24 through 53 in this report:

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of Tipperary Corporation:

In our opinion, the accompanying consolidated balance sheets and related consolidated statements of operations, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Tipperary Corporation and its subsidiaries at December 31, 2001, December 31, 2000 and September 30, 2000, and the results of their operations and their cash flows for the year ended December 31, 2001, the three months ended December 31, 2000 and the fiscal years ended September 30, 2000 and 1999 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Denver, Colorado
March 21, 2002

TIPPERARY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
($ in thousands except per share data)

ASSETS	December 31, 2001	December 31, 2000	September 30, 2000
Current assets:			
Cash and cash equivalents	$ 9,415	$ 1,579	$ 5,897
Restricted cash	1,312	1,459	-
Receivables	2,518	987	1,515
Prepaid drilling costs	2,821	2,219	2,239
Other current assets	293	212	340
Total current assets	16,359	6,456	9,991
Property, plant and equipment, at cost:			
Oil and gas properties, full cost method	74,005	67,833	63,342
Other property and equipment	3,903	1,069	1,039
	77,908	68,902	64,381
Less accumulated depreciation, depletion and amortization	(23,486)	(22,402)	(22,176)
Property, plant and equipment, net	54,422	46,500	42,205
Deferred loan costs	6,726	381	337
Other noncurrent assets	20	13	13
	$ 77,527	$ 53,350	$ 52,546
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Current portion of long-term debt	$ 2,231	$ 317	$ 353
Accounts payable	4,022	3,312	2,137
Accrued liabilities	1,004	339	455
Royalties payable	234	232	205
Total current liabilities	7,491	4,200	3,150
Long-term debt, net of current portion	12,183	11,589	10,633
Minority interest	734	42	128
Commitments and contingencies (Note 12)			
Stockholders' equity:			
Preferred stock:			
Cumulative; par value $1.00; 10,000,000 shares authorized; none issued	-	-	-
Non-cumulative, par value $1.00; 10,000,000 shares authorized; none issued	-	-	-
Common stock; par value $.02; 50,000,000 shares authorized; 38,981,087 shares issued and 38,971,489 shares outstanding at December 31, 2001; 24,482,185 issued and 24,472,587 outstanding at December 31, 2000; 24,480,185 issued and 24,470,587 outstanding at September 30, 2000	780	490	490
Capital in excess of par value	149,499	123,013	123,009
Accumulated deficit	(93,135)	(85,959)	(84,839)
Treasury stock, at cost; 9,598 shares	(25)	(25)	(25)
Total stockholders' equity	57,119	37,519	38,635
	$ 77,527	$ 53,350	$ 52,546

See accompanying notes to Consolidated Financial Statements.

TIPPERARY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
(in thousands, except per share data)

	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	Fiscal Years Ended September 30 1999
Revenues	$ 3,557	$ 864	$ 8,624	$ 7,921
Costs and expenses:				
Operating	2,218	442	4,233	4,587
General and administrative	4,257	1,170	3,732	2,262
Depreciation, depletion and amortization	1,017	225	1,971	3,154
Gain on sale of oil and gas properties	-	-	(4,837)	-
Impairment of prepaid drilling costs	900	-	557	-
Write-down of oil and gas properties	-	-	-	5,727
Total costs and expenses	8,392	1,837	5,656	15,730
Operating income (loss)	(4,835)	(973)	2,968	(7,809)
Other income (expense):				
Interest income	129	37	109	13
Interest expense	(2,848)	(302)	(1,662)	(1,633)
Foreign currency exchange gain (loss)	(5)	32	(166)	19
Total other expense	(2,724)	(233)	(1,719)	(1,601)
Income (loss) before income taxes	(7,559)	(1,206)	1,249	(9,410)
Income tax benefit	(1)	-	-	-
Deferred income tax expense	-	-	1,573	-
Loss before minority interest	(7,558)	(1,206)	(324)	(9,410)
Minority interest in loss of subsidiary	382	86	367	115
Net income (loss)	$ (7,176)	$ (1,120)	$ 43	$ (9,295)
Net income (loss) per share - basic and diluted	$ (.28)	$ (.05)	$ -	$ (.63)
Weighted average shares outstanding - basic and diluted	25,842	24,471	21,204	14,689

See accompanying notes to Consolidated Financial Statements.

TIPPERARY CORPORATION AND SUBSIDIARIES
Consolidated Statement of Stockholders' Equity
(in thousands)

	Common Stock		Capital in excess of	Accumulated	Treasury Stock		
	Shares	Amount	par value	Deficit	Shares	Amount	Total
Balance at September 30, 1998	13,134	$ 263	$ 105,564	$ (75,476)	28	$ (71)	$ 30,280
Net loss	-	-	-	(9,295)	-	-	(9,295)
Common stock issued for cash	2,000	40	2,413	-	-	-	2,453
Treasury stock issued to officers in lieu of cash compensation	18	-	-	(32)	(18)	46	14
Balance at September 30, 1999	15,152	303	107,977	(84,803)	10	(25)	23,452
Net income	-	-	-	43	-	-	43
Common stock and warrants issued							
To acquire oil and gas property	1,463	29	2,882	-	-	-	2,911
For cash	7,849	158	12,132	-	-	-	12,290
Exercise of stock options	7	-	18	-	-	-	18
Preferred dividends	-	-	-	(79)	-	-	(79)
Balance at September 30, 2000	24,471	490	123,009	(84,839)	10	(25)	38,635
Net loss	-	-	-	(1,120)	-	-	(1,120)
Exercise of stock options	2	-	4	-	-	-	4
Balance at December 31, 2000	24,473	490	123,013	(85,959)	10	(25)	37,519
Net loss	-	-	-	(7,176)	-	-	(7,176)
Common stock issued							
To acquire oil and gas property	675	14	1,674	-	-	-	1,688
For cash	13,823	276	24,812	-	-	-	25,088
Balance at December 31, 2001	38,971	$ 780	$ 149,499	$ (93,135)	10	$ (25)	$ 57,119

See accompanying notes to Consolidated Financial Statements.

TIPPERARY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
($ in thousands)

	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	Fiscal Years Ended September 30 1999
Cash flows from operating activities:				
Net income (loss)	$ (7,176)	$ (1,120)	$ 43	$ (9,295)
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	1,017	225	1,971	3,154
Write-down of oil and gas properties	-	-	-	5,727
Amortization of deferred loan costs	1,302	-	-	-
Issuance of compensatory common stock	-	-	-	14
Minority interest in loss of subsidiary	(382)	(86)	(367)	(115)
Gain on sale of oil and gas properties	-	-	(4,837)	-
Deferred income tax expense	-	-	1,573	-
Change in assets and liabilities				
(Increase) decrease in receivables	(205)	528	10	(117)
(Increase) decrease in prepaid drilling costs and other current assets	(683)	148	(1,680)	(824)
Increase in accounts payable and accrued liabilities	1,809	1,059	174	1,294
Increase in royalties payable	2	27	4	45
Other	-	-	-	1
	2,860	1,901	(3,152)	9,179
Net cash provided (used) by operating activities	(4,316)	781	(3,109)	(116)
Cash flows from investing activities:				
Proceeds from sale of oil and gas properties, net of expenses	2,782	-	17,279	705
Capital expenditures	(17,457)	(4,521)	(10,141)	(6,179)
Additional investing activities	(8)	-	-	-
Net cash provided (used) by investing activities	(14,683)	(4,521)	7,138	(5,474)
Cash flows from financing activities:				
Proceeds from borrowings	24,500	1,000	1,585	7,019
Principal repayments	(21,992)	(79)	(12,038)	(4,780)
Proceeds from issuance of stock and warrants	25,575	4	12,307	2,538
Proceeds from subsidiary sale of stock	-	-	-	610
(Increase) decrease in restricted cash	147	(1,459)	-	-
Payment of dividends	-	-	(79)	-
Payments for other financing activities	(1,395)	(44)	(337)	-
Net cash provided (used) by financing	26,835	(578)	1,438	5,387
Net increase (decrease) in cash and cash equivalents	7,836	(4,318)	5,467	(203)
Cash and cash equivalents at beginning of year	1,579	5,897	430	633
Cash and cash equivalents at end of year	$ 9,415	$ 1,579	$ 5,897	$ 430
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest	$ 1,879	$ 311	$ 1,398	$ 1,393
Non-cash investing and financing activities -				
Issuance of stock to acquire oil and gas properties	$ (1,688)	$ -	$ (2,911)	$ -
Receivable from sale of oil and gas properties	$ 1,158	$ -	$ -	$ -
Issuance of subsidiary stock in exchange for contractual payment rights	$ (1,074)	$ -	$ -	$ -
Deferred financing costs	$ 6,843	$ -	$ -	$ -
Net payables for capital expenditures	$ 431	$ -	$ -	$ -

See accompanying notes to Consolidated Financial Statements.

NOTE 1 - ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Tipperary Corporation and its subsidiaries (the "Company" or "Tipperary") are principally engaged in the exploration for and development and production of natural gas. The Company is primarily focused on coalbed methane properties, with its major producing property located in Queensland, Australia. The Company's activities in Australia are conducted through its 90%-owned Australian subsidiary, Tipperary Oil & Gas (Australia) Pty Ltd ("TOGA"), which owns a 65% undivided interest in the Comet Ridge project. Tipperary also holds exploration permits in Queensland and is involved in coalbed methane and conventional gas exploration in the United States through projects in Colorado and Wyoming. The Company seeks to increase its reserves through exploration and development projects and the acquisition of producing properties. During fiscal 2000, the Company disposed of a majority of its conventional oil and gas properties in the United States. The Company is a majority owned subsidiary of Slough Estates USA Inc. ("Slough").

On November 30, 2000, the Board of Directors elected to change the Company's fiscal year end from September 30 to December 31. The Company filed a report on Form 10-KSB for the three months ended December 31, 2000 ("transition period"). References in this report to the Company's fiscal years are to those ended September 30.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Tipperary Corporation, its wholly-owned subsidiaries, Tipperary Oil & Gas Corporation and Burro Pipeline Corporation, and its 90%-owned subsidiary, TOGA. Slough owns the remaining 10% of TOGA. All intercompany transactions and balances have been eliminated.

Liquidity and Operations

The Company's anticipated capital expenditures during 2002 total approximately $13 million. In Australia, the Company expects to incur capital costs of $10 million, of which $6 million will be for development drilling and for equipment and facilities required to gather anticipated gas production volumes, and $4 million will be for exploration activities on the ATP. The Company plans to incur $1.5 million for its net share of the costs to drill up to 10 wells in its Lay Creek project and to incur approximately $1.5 million on its remaining exploration and development projects in Australia and the United States.

The Company anticipates that cash on hand and anticipated borrowings of $5 million under the TCW Credit Agreement will fund operations and capital expenditures through 2002. In order to fund any capital expenditures in 2002 in excess of these cash resources and to fund capital expenditures beyond 2002, the Company will require alternative sources of capital. Additional sources of funding are expected to include additional debt financings and asset sales. The Company will seek debt financing for further development of the Comet Ridge project and expects sales of domestic assets to provide funding for other capital asset acquisitions or expenditures. The Company plans to sell its interest in the West Buna field in east Texas during 2002 and will continue to seek industry partners in domestic exploration projects. With the sale of interests in its prospective acreage, the Company expects to generate cash to reduce its investment in individual projects. However, in the event that sufficient funding cannot be obtained, the Company will be required to curtail planned expenditures and may have to sell additional acreage and/or relinquish acreage.

Use of Estimates and Significant Risks

The preparation of Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in these financial statements and accompanying notes. The more significant areas requiring the use of estimates relate to the recoverability of prepaid drilling costs and the determination of oil and gas reserve quantities and future net cash flows. Actual results could differ from those estimates.

The Company is subject to a number of risks and uncertainties inherent in the oil and gas industry. Among these are risks related to fluctuating oil and gas prices, uncertainties related to the estimation of oil and gas reserves and the value of such reserves, effects of competition and extensive environmental regulation, risks associated with the search for and the development of oil and gas reserves, uncertainties related to foreign operations, and many other factors, many of which are beyond the Company's control. The Company's financial condition and results of operations depend significantly upon the prices received for natural gas. These prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Company.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents. Included in cash and cash equivalents as of December 31, 2001 is approximately $1.3 million that is restricted under the terms of the credit agreement discussed in Note 4.

Concentrations of Credit Risk

The Company maintains demand deposit accounts with two banks in Denver, Colorado and one bank in Brisbane, Queensland, Australia and invests cash in money market accounts which the Company believes have minimal risk of loss.

The Company sells gas and oil production to various purchasers. The risk of non-payment by the purchasers is considered minimal and the Company does not obtain collateral for its receivables.

Financial Instruments

At December 31, 2001, based on rates available for similar types of debt, the Company believes that the fair value of its long-term debt was not materially different from its carrying amount.

Derivative Instruments and Hedging Activities

The Company has periodically used derivatives to hedge a portion of its U.S. crude oil and natural gas production. In the future, the Company may enter into derivative contracts to mitigate the risk of foreign currency exchange rate fluctuations.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Effective with the adoption of SFAS No. 133, all derivatives are recognized on the balance sheet and measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is either recognized in income along with an offsetting adjustment to the basis of the item being hedged for fair value hedges or deferred in other comprehensive income to the extent the hedge is effective for cash flow hedges. To qualify for hedge accounting, the derivative must qualify as either a fair-value, cash-flow or foreign-currency hedge.

The Company has not hedged any of its production since March 2000. The Company did not hedge its foreign currency exchange risk during 2001, 2000 or 1999. During the fiscal years ended September 30, 2000 and 1999, the Company hedged a total of 45,000 barrels (approximately 23%) and 95,000 barrels (approximately 27%) of its oil production. Net receipts (payments) pursuant to the Company's hedging activities for fiscal 2000 and 1999 were ($285,000) and ($200,000), respectively.

Property, Plant and Equipment

The Company follows the full cost method to account for its oil and gas exploration and development activities. Under the full cost method, all costs incurred which are directly related to oil and gas exploration and development are capitalized and subjected to depreciation, depletion and amortization ("DD&A"). Depletable costs also include estimates of future development costs of proved reserves. Costs related to undeveloped oil and gas properties may be excluded from depletable costs until such properties are evaluated as either proved or unproved. The net capitalized costs are subject to a ceiling limitation. See Note 5. Gains or losses upon disposition of oil and gas properties are treated as adjustments to capitalized costs, unless the disposition represents a significant portion of the Company's proved reserves. A separate cost center is maintained for expenditures applicable to each of the United States and Australia, the two countries in which the Company conducts exploration and/or production activities.

Repairs and maintenance are expensed; renewals and betterments are capitalized. Certain indirect costs, including a portion of general and administrative expenditures and interest expense have been capitalized to the full cost pool.

Upon sale or retirement of property, plant and equipment other than oil and gas properties, the applicable costs and accumulated depreciation are removed from the accounts and a gain or loss is recognized in the current period.

Revenue Recognition and Gas Imbalances

The Company recognizes oil and natural gas revenue from its interests in producing wells as natural gas and oil is produced and sold from those wells. Tipperary uses the sales method of accounting for these revenues. Under the sales method, revenues are recognized based on actual volumes sold to purchasers. With natural gas production operations, joint owners may take more or less than the production volumes entitled to them under the governing agreement. The Company records a natural gas imbalance in other liabilities if its excess takes of natural gas exceed its remaining proved reserves for the property. As of December 31, 2001, the Company had taken and sold more than its share of natural gas volumes produced from the Comet Ridge project, and was overproduced by approximately 684,000 Mcf. Based on the average price of $1.11 per Mcf received during 2001 from these sales, this represented $760,000 in gas revenues. No liability has been recorded for the excess volumes taken, as they do not exceed the Company's share of remaining proved reserves. Under the terms of the governing gas balancing agreement, the Company may be required to reduce the monthly volumes it delivers by up to 50% in order to enable underproduced parties to take more than their share of the gas and cure the imbalance.

The Company receives rental income for the use of a drilling rig owned by TOGA and leased to a third party drilling contractor in Australia. See Note 6. The Company includes in revenue and expense rental income and depreciation expense when the rig is used to drill wells for other parties. Rig rental income and depreciation expense are capitalized to the Company's Australia full cost pool, rather than recorded as income and expense, when the rig is used to drill wells on the Company's properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of oil and gas properties is provided using the units-of-production method computed using proved oil and gas reserves.

Abandonment, restoration, dismantlement costs and salvage value are taken into account in determining depletion rates. These costs are generally expected to equal the proceeds from equipment salvage upon abandonment of such properties. When estimated abandonment costs exceed the salvage value, the excess cost is accrued and expensed.

Depreciation and amortization of other property, plant and equipment and other assets is provided using the straight-line method computed over estimated useful lives ranging from five to fifteen years.

Income Taxes

Deferred income taxes are provided on the differences between the tax bases of assets or liabilities and their reported amounts in the financial statements. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recovered or settled, respectively.

Earnings (Loss) Per Share

Basic earnings per share is computed based on the weighted average number of shares outstanding. Diluted earnings per share reflects the potential dilution that would occur if options and warrants were exercised.

Foreign Currency

The Company considers the functional currency of its Australian subsidiary to be the U.S. dollar. Foreign currency denominated current assets and liabilities are generally remeasured into U.S. dollars at end-of-period exchange rates. Foreign currency revenues and expenses are generally remeasured at average exchange rates in effect during the year. Exchange gains and losses arising from remeasured foreign currency denominated monetary assets and liabilities are included in the Statement of Operations.

Stock-Based Compensation

Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation," ("FAS 123") encourages, but does not require, companies to record the compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to continue to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees", ("APB 25") and has applied the disclosure provisions of FAS 123. Accordingly, compensation cost for fixed stock options and warrants is measured as the excess, if any, of the quoted market price of the Company's stock at the date of the grant over the amount an employee must pay to acquire the stock. See Note 10.

Financing Costs

Costs incurred to obtain financing through the issuance of stock are accounted for as a reduction of the related proceeds. Costs attributable to raising debt financing, including the present value of future royalty payments, are amortized over the term of the related credit agreement.

Minority Interest

Slough's 10% ownership in TOGA has been accounted for as a minority interest in the accompanying Consolidated Financial Statements.

Significant Customers

In Australia, the Company is currently selling 100% of its gas to ENERGEX Retail Pty Ltd, an unaffiliated customer, under two five-year gas supply contracts which commenced in January 1999 and June 2000, respectively. The Company had domestic sales in excess of 10% of total U.S. revenues to the oil and gas customers listed below.

	Year Ended December 31	Three Months Ended December 31	Fiscal Years Ended September 30	
	2001	2000	2000	1999
Sunoco, Inc.	-	36%	14%	-
BPAmerica Production Co.	77%	39%	22%	23%
Smith Production Inc.	22%	-	-	-
Versado Gas Processors, LLC	-	-	12%	11%
Plains Marketing, LP	-	-	-	10%

Since numerous purchasers compete to purchase both oil and gas from the Company's properties in both the United States and Australia, the Company does not believe that the loss of any single existing purchaser would have a material adverse impact on its ability to sell its production to another purchaser at similar prices. Nonpayment by such purchasers, however, could adversely affect operating results.

Segment Information

The Company has one business segment; oil and gas exploration, development and production. The Company operates in two geographic areas, the United States and Australia. See Notes 13 and 14.

Issuance of Subsidiary Common Stock

Sales of stock by a subsidiary are accounted for as capital transactions. No gain or loss is recognized on these transactions.

Impact of New Accounting Pronouncements

In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement No. 144 ("SFAS 144") "Accounting for the Impairment or Disposal of Long-Lived Assets," which replaces SFAS 121, "Accounting for the Impairment or Disposal of Long-Lived Assets" and will be effective for financial statements issued for fiscal years beginning after December 15, 2001. SFAS 144 requires that long-lived assets to be disposed of by sale be measured at the lower of the carrying amount or fair value less selling costs, whether reported in continuing operations or in discontinued operations. SFAS 144 changes the reporting of discontinued operations to include all components of an entity with operations that can be segregated from the rest of the entity and that will be eliminated from the ongoing operations of the entity as a result of a disposal transaction. The Company will adopt SFAS 144, effective January 1, 2002. The Company has not yet determined whether SFAS 144 will have a material impact on its financial position or results of operations.

In July 2001, the FASB issued SFAS 141 "Business Combinations" and SFAS 142, "Goodwill and Other Intangible Assets." SFAS 141 requires that all business combinations entered into subsequent to June 30, 2001 be accounted for under the purchase method of accounting and that certain acquired intangible assets in a business combination be recognized and reported as assets separately from goodwill. SFAS 142 requires that amortization of goodwill be replaced with an annual impairment test of the goodwill's carrying value. Tipperary adopted SFAS 141 in July 2001 and will adopt SFAS 142 effective January 1, 2002. The Company does not believe that its adoption of SFAS 141 and SFAS 142 will have a material effect on its financial statements.

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations," which provides accounting requirements for retirement obligations associated with tangible long-lived assets, including the timing of liability recognition, initial measurement of the liability, allocation of asset retirement cost to expense, subsequent measurement of the liability, and financial statement disclosures. SFAS 143 requires that asset retirement costs be capitalized along with the cost of the related long-lived asset. The asset retirement costs should then be allocated to expense using a systematic and rational method. The transition adjustment resulting from the adoption of SFAS 143 would be reported as a cumulative effect of a change in accounting principle. Tipperary will adopt the statement no later than January 1, 2003. The Company has not yet determined whether SFAS 143 will have a material impact on its financial position or results of operations.

Comparable Transition Period

Summarized statements of operations information for the three–month transition period ended December 31, 2000 and three months ended December 31, 1999 are shown below (in thousands, except per share data):

	2000	(Unaudited) 1999
Revenues	$ 864	$ 2,919
Costs and expenses	1,837	2,740
Operating income (loss)	(973)	179
Other income (expense)	(233)	(539)
Loss before income taxes	(1,206)	(360)
Income tax expense	-	-
Loss before minority interest	(1,206)	(360)
Minority interest in loss of subsidiary	86	54
Net loss	$ (1,120)	$ (306)
Net loss per share - basic and diluted	$ (.05)	$ (.02)
Weighted-average shares outstanding - basic and diluted	24,471	15,436

NOTE 2 - RELATED PARTY TRANSACTIONS

At November 30, 2001, the Company had a corporate loan of $17,500,000 due Slough. The Company retired this debt on December 5, 2001 with proceeds from a rights offering. See Note 10.

Slough has also advanced TOGA $2.5 million for the purchase of a drilling rig which TOGA has leased to an unaffiliated drilling contractor in Australia. This loan bears interest at a fixed rate of 10% per annum and matures on July 31, 2003. Payments are due monthly equal to all rents TOGA received from the drilling contractor and for accrued interest on the balance of the loan. In November 2001, Tipperary made its first principal payment of $75,000 leaving a total debt balance of $2,425,000 as of December 31, 2001. The Company recorded a current liability as of December 31, 2001 for $760,000 of the loan balance based on projected rental payments expected from the drilling contractor during 2002.

On December 22, 1998, the Company issued to Slough 10% of the common stock of its Australian subsidiary in accordance with the terms of a debt and equity financing transaction. In 2001, the Company issued Slough 385,821 additional shares of its Australian subsidiary in exchange for Slough's contractual payment right to a portion of the Company's revenues from the Comet Ridge project. Slough received this contractual payment right in fiscal 1999 in connection with a Comet Ridge project financing loan, discussed below.

Related party debt due Slough at December 31, 2000 included the corporate loan in the amount of $7,500,000 and the project financing loan with a balance of $4,406,000 (of which the current portion due was $317,000). Subsequent to December 31, 2000, the Company repaid the project-financing loan using the initial proceeds of its financing with TCW Asset Management Company ("TCW") discussed in Note 4. Interest was payable on the Slough loan at a rate of 10% per annum. Interest and principal payments combined were equal to 75% of the cash flow, as defined in the note, from the Comet Ridge properties and were due quarterly. Under the terms of this loan, the Company was also required to pay an additional finance charge of 7% of gross proceeds received from sales from certain existing wells through repayment of the loan.

On December 23, 1999, the Company completed a financing transaction with Slough in which Slough purchased 6,329,114 shares of the Company's 1999 Series A Convertible Cumulative Preferred Stock for $10,000,000, or $1.58 per share. At closing, Slough converted 2,900,000 shares of the convertible preferred stock into 2,900,000 shares of restricted common stock. Also, at closing, the Company issued Slough warrants for 1,200,000 shares of common stock at an exercise price of $2.00 per share. The warrants may be exercised during an eight-year period beginning December 23, 2001 and ending December 23, 2009. Effective February 29, 2000, Slough converted the remaining shares of preferred stock into 3,429,114 shares of restricted common stock. During the quarter ended June 30, 2000, the Company paid a cash dividend of approximately $79,000 to Slough for the period the preferred shares were outstanding.

NOTE 3 - OIL AND GAS PROPERTY SALES

During fiscal 2000, the Company sold approximately 75% of its domestic proved reserve volumes from conventional oil and gas properties in connection with a redirection of focus toward increasing reserves from coalbed methane properties. The Company received approximately $17.2 million (net of selling expenses) from the sales of various interests in producing oil and natural gas mineral leaseholds which comprised the majority of its domestic full cost pool. A gain of approximately $4.8 million was recorded based upon the allocation of capitalized costs between reserves sold and reserves retained.

The Company has a 50% working interest in and serves as operator of the Lay Creek project in Moffat County, Colorado. The project covers various leasehold interests over approximately 81,000 acres. Koch Exploration Company ("Koch"), an unaffiliated third party, holds the remaining 50% working interest under the terms of an agreement to jointly conduct exploratory drilling over this area. Koch paid the Company approximately $2 million for this interest at closing in May 2001 and agreed to pay the Company within 18 months, or by October 2002, approximately $2 million for the Company's share of costs to drill and complete wells on the project acreage.

The Company has established a receivable for the $2 million to be received from Koch for reimbursement of the Lay Creek drilling costs discussed above. The receivable has been reduced by approximately $842,000 for costs incurred to drill and complete the two wells, leaving a balance as of December 31, 2001 of $1,158,000 due the Company on or before October 4, 2002. The Company expects to realize this receivable in full during 2002 through additional drilling that is planned through the third quarter of 2002.

NOTE 4 - COMET RIDGE PROJECT FINANCING AND ACQUISITIONS

On April 28, 2000, the Company entered into a credit agreement with TCW ("Credit Agreement") that provides a borrowing facility of up to $17 million to be funded on or before December 31, 2001 upon the satisfaction of certain conditions. The obligation to repay the advances and accrued interest is evidenced by senior secured promissory notes bearing interest at the rate of 10% per annum and payable quarterly. The Company must also make monthly payments to TCW equal to a 6% overriding royalty from the gas sales revenues received by TOGA from the Comet Ridge project. Upon payment of the loan in full, TCW has the option to sell this overriding royalty interest to the Company at the net present value of the royalty interest's share of future net revenues from the then proved reserves, discounted at a rate of 15% per annum. The Company also has the right to purchase the royalty interest from TCW, when the loan has been repaid in full and TCW has received a 15% internal rate of return on its investment, for the net present value of the royalty's share of future net revenues from the then proved reserves, discounted at a rate of 15% per annum. Principal payments are due quarterly in an amount equal to the greater of a percentage of TOGA's operating cash flow as defined or a scheduled minimum principal payment. The scheduled minimum principal payments begin in March 2003 and will be equal to 5% of the unpaid principal balance, increasing to 9% in March 2004 and 10% in March 2005. The outstanding principal balance is due in full on March 30, 2006. If the Company fails to make principal payments as required by the Credit Agreement, TCW may require all obligations to be immediately due and payable. The Credit Agreement requires that TOGA maintain working capital of at least $1,000,000.

In February 2001, the parties to the Credit Agreement executed an amended and restated agreement and the Company received an initial loan advance of $7.5 million. Proceeds from this initial advance were used to repay the $4,406,000 project-financing loan relating to the Comet Ridge project in Queensland, Australia, due to Slough and pay $1.5 million in initial costs of an additional 20-well drilling program on the Comet Ridge project, with the balance provided as working capital for lender-approved purposes. Upon the receipt of this initial funding, the Company recorded deferred financing costs of approximately $6.8 million, which is the present value (discounted at 15%) of the overriding royalty conveyed to TCW. This cost reduced the book value of oil and gas properties and is being amortized as interest expense over the life of the loan. Deferred financing costs at December 31, 2001 also include approximately $1,056,000 of other costs incurred to obtain the TCW financing, which are likewise being amortized to interest expense over the life of the loan.

The Company received $4.5 million of additional loan advances under the Credit Agreement, bringing the total loan balance to $12 million as of December 31, 2001. Of the total of $12 million currently due TCW, the Company has used $7.3 million to fund advances to the operator of the Comet Ridge project for the 20-well drilling program. The operator has drilled nine wells under the program and has constructed a connecting pipeline that allows the Company to sell between three and four MMcf per day of gas production that was previously flared at the wellhead. TCW has recently extended the funding expiration date of December 31, 2001 to April 30, 2002 and the Company anticipates borrowing the remaining $5 million for further development of the Comet Ridge project.

During 2001, the Company increased its interest in the comet Ridge project from 62.25% to 65%. In June 2001, the Company acquired a 2.5% capital-bearing interest for $1,688,000. The purchase price was paid to the seller with the issuance of 675,000 shares of the Company's restricted common stock with a value of $2.50 per share on the date the transaction closed. The Company acquired an additional .25% interest in the Comet Ridge project for approximately $169,000 in cash during August 2001, bringing the Company's total capital-bearing interest to 65%. See Note 10 for a discussion of additional interest acquired during fiscal 2000.

NOTE 5 - OIL AND GAS FULL COST POOLS

Under the full cost method of accounting, capitalized oil and gas property costs, less accumulated DD&A and related deferred income taxes, may not exceed a "ceiling" comprised of the total of the present value of future net revenues from proved reserves, plus the lower of cost or market value of unproved properties, less related income tax effects. This "ceiling test" must be performed on a quarterly basis and is performed separately for each full cost pool. The Company maintains, as required, a separate cost center for expenditures applicable to each country in which it conducts exploration and/or production activities.

Australia

The Company's Australia full cost pool includes acquisition, drilling and completion costs, seismic costs, and costs to construct gas gathering lines. The Company holds an interest in the Comet Ridge coalbed methane project in Queensland and has acquired and begun exploration activities on its own Authorities to Prospect (ATPs) in Queensland. As of December 31, 2001, the capitalized costs applicable to the Australia full cost pool were approximately $45,270,000. Based on prices on both December 31, 2001 and December 31, 2000, the ceiling value exceeded the net capitalized costs in the Australia full cost pool and no impairment was required.

United States

The Company's domestic full cost pool includes capital costs incurred in domestic property acquisition, exploration and development. The net book value of the United States full cost pool as of December 31, 2001 was $9,152,000. Based on prices on both December 31, 2001 and December 31, 2000, the ceiling value exceeded the net capitalized costs in the U.S. full cost pool and no impairment was required. However, in fiscal 1999 the Company recorded a non-cash impairment of its domestic oil and gas properties in the amount of $5,727,000 pursuant to the ceiling limitation.

Costs attributable to unproved oil and gas leases and exploration costs that have been excluded from depletable costs pending further evaluation are as follows (in thousands):

Period Incurred	Australia	United States
2001	$ 1,062	$ 6,661
Transition period ended December 31, 2000	818	2,471
Fiscal 2000	526	1,866
Fiscal 1999	317	90
Total unproved oil and gas property additions	$ 2,723	$ 11,088
Sales and carried interest proceeds	-	(3,875)
Transferred to evaluated full cost pool	(383)	(1,440)
Total unproved oil and gas property activity	$ 2,340	$ 5,773

NOTE 6 - OTHER PROPERTY AND EQUIPMENT

In 2001, TOGA acquired a drilling rig ("Soilmec rig") and related equipment from a manufacturer in Italy for a total cost of approximately $2.7 million. TOGA acquired the Soilmec rig for use by an unrelated drilling contractor in Queensland to drill wells on the Comet Ridge project under a turnkey drilling contract that would provide for accelerated drilling at a reduced cost. TOGA leased the drilling rig to the contractor ("Lessee") under the terms of an agreement that provides that the Lessee use the rig to drill on the Comet Ridge project and TOGA's other ATPs. To the extent the rig is not being used for TOGA's drilling activities, it may, with TOGA's consent, be used by the Lessee to drill wells for other parties. The lease payments are structured to be due and payable with the drilling of each well. No interest or finance charge accrues on the lease, but the Company benefits from reduced costs to drill each well on the Comet Ridge project or its other ATPs. In the case of drilling on the Comet Ridge project, the Company's co-owners also benefit from their proportionate share of any cost reductions. The lessee also received a two-year option to buy the rig and related equipment at TOGA's net cost remaining after lease payments.

During 2001, the rig was used to drill two wells on the Comet Ridge project, two wells on the Company's ATP and one well for a third party. The Company received rents during 2001 totaling $75,000, which were used for principal payments to Slough. See "Revenue Recognition and Gas Imbalances" under Note 1 for a discussion of how rig rental income and depreciation expense are reflected in the Company's financial statements.

NOTE 7 - IMPAIRMENT OF PREPAID DRILLING COSTS

In 2001 and in the fiscal year ended September 30, 2000, the Company recorded charges to expense of $900,000 and $557,000, respectively, for prepaid drilling costs that the Company estimated would not be realized as either capital expenditures or cash refunds. These sums were paid to Tri-Star Petroleum Company ("Tri-Star") as operator of the

Comet Ridge project in Australia, with whom the Company has been in litigation during the last few years. The Company may realize an actual loss in excess of this estimate or it may recover a portion or all of these costs depending on the actions of Tri-Star and the outcome of the litigation. The Company may also record gains or losses upon resolution of the Comet Ridge litigation that are unrelated to these prepaid drilling costs. Through December 31, 2001, the Company had made payments totaling approximately $1.1 million into the registry of the 238th Judicial District Court in Midland County, Texas for disputed portions of joint interest billings from Tri-Star. At the appropriate time, the court will determine the disposition of the funds paid into its registry. The funds may be returned to the Company, in whole or in part, or awarded to Tri-Star in whole or in part. If, and to the extent funds are returned, the Company will reduce its full cost pool for recovered capital costs and will record a gain for recovered operating costs. If, and to the extent funds are awarded to Tri-Star, the Company will not record an additional loss.

NOTE 8 - LOSS PER SHARE

The following table sets forth the computation of basic and diluted earnings (loss) per share (in thousands except per share data):

	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	Fiscal Years Ended September 30 1999
Numerator:				
Net income (loss)	$ (7,176)	$ (1,120)	$ 43	$ (9,295)
Less: preferred stock dividends	-	-	(79)	-
Net loss available for common stockholders	(7,176)	$ (1,120)	$ (36)	$ (9,295)
Denominator:				
Weighted-average shares outstanding	25,842	24,471	21,204	14,689
Effect of dilutive securities:				
Assumed exercise of dilutive options	-	-	-	-
Weighted-average shares and dilutive potential common shares	25,842	24,471	21,204	14,689
Basic loss per share	$ (.28)	$ (.05)	$ -	$ (0.63)
Diluted loss per share	$ (.28)	$ (.05)	$ -	$ (0.63)
Potentially dilutive common stock from the exercise of options and warrants not included in EPS because the effect would have been antidilutive	561	914	640	-
Total options and warrants which could potentially dilute basic EPS in future periods	3,504	3,463	3,407	1,763

NOTE 9 - LONG-TERM DEBT

Long-term debt is summarized below (in thousands):

	December 31 2001	December 31 2000	September 30 2000
Senior secured promissory notes to TCW, 10%, maturing March 30, 2006	$ 11,989	$ -	$ -
Promissory note to Slough, 10%, maturing July 31, 2003	2,425	-	-
Promissory note to Slough, 10%, maturing November 22, 2004	-	4,406	4,486
Promissory note to Slough, LIBOR plus 3.5%, maturing March 31, 2003	-	7,500	6,500
	14,414	11,906	10,986
Less current portion	(2,231)	(317)	(353)
Total	$ 12,183	$ 11,589	$ 10,633

NOTE 10 - STOCKHOLDERS' EQUITY

Common Stock Issuances

In December 2001, the Company issued 13,823,902 shares of its common stock in connection with a rights offering. As a result of the offering, the Company raised approximately $25,575,000, of which $17,500,000 was used to retire debt owed to Slough. The increase in stockholders' equity was recorded net of $610,000 in costs related to the offering.

In June 2001, the Company issued 675,000 shares of common stock to an individual in exchange for a 2.5% interest in the Comet Ridge project. The common stock issued had a value of $1,688,000 on the date the transaction closed. The shares were not registered under the Securities Act of 1933 (the "Securities Act") when issued, but rather were issued privately by the Company pursuant to the exemption from registration provided by Section 4(2) of the Securities Act. These shares were subsequently included in a Registration Statement filed on Form S-3/A on January 4, 2002.

During the three months ended December 31, 2000 and during fiscal 2000, the Company issued a total of 9,000 shares of common stock to employees pursuant to the exercise of incentive stock options.

During fiscal 2000, the Company issued 6,329,114 shares of its common stock to Slough in connection with the refinancing agreement dated December 23, 1999. See Note 2. In February 2000, the Company issued a total of 2,682,316 shares of its common stock in connection with the acquisition of additional interests in the Comet Ridge coalbed methane project in Queensland, Australia. An additional acquisition of a 1% interest in the project was purchased in July 2000 with the issuance of 300,000 shares of common stock. The total purchase price of the additional interests acquired was approximately $6,211,000 and included cash of $3,300,000 and stock valued at $2,911,000. The cash portion of the combined purchase price was paid using cash on hand of $900,000 and $2,400,000 of proceeds from the sale of 1,518,988 shares of common stock at $1.58 per share and warrants covering 288,000 shares to two individual investors. The remaining purchase price of approximately $2,911,000 was paid to the sellers with the issuance of 1,163,328 shares of common stock at $1.60 per share in February 2000 and 300,000 shares at $3.50 per share in July 2000. The shares under each of the foregoing transactions were not registered under the Securities Act of 1933 (the "Securities Act") when issued, but rather were issued privately by the Company pursuant to the exemption from registration provided by Section 4(2) of the Securities Act. During 2001 the Company filed Registration Statements on Form S-3, SEC File Nos. 333-56944 and 333-75310, that included 2,138,328 of the shares issued to sellers of interests in the Comet Ridge project and 288,000 shares covered by the warrants issued to two other individuals. Shares of common stock outstanding that remain unregistered from the issuances disclosed above include 1,518,988 issued to two individual investors and 6,329,114 shares issued to Slough.

Stock Based Compensation Plan

The Company grants stock options under stock-based incentive compensation plans (the "Plan"). The Company applies APB Opinion 25 and related Interpretations in accounting for the Plan. In 1995, the FASB issued SFAS 123 "Accounting for Stock-Based Compensation" which, if fully adopted by the Company, would change the methods the Company applies in recognizing the cost of the Plan. Adoption of the cost recognition provisions of SFAS 123 is optional and the Company has decided not to elect these provisions of SFAS 123. However, pro forma disclosures as if the Company adopted the cost recognition provisions of SFAS 123 in 1995 are required by SFAS 123 and are presented below.

The 1987 Employee Stock Option Plan (the "1987 Plan") provided for option grants for a maximum of 383,000 shares. The 1987 Plan expired December 31, 1996. The 264,400 options outstanding as of December 31, 2001 under this plan have a term of ten years ending no later than October 2006, an exercise price equal to the fair market value of the stock on the date of grant and qualify as incentive stock options as defined in the Internal Revenue Code of 1986 ("the Code"). These options remain in full force and effect pursuant to each option's terms.

The 1997 Long-Term Incentive Plan (the "1997 Plan") was adopted to replace the expired 1987 Plan. The 1997 Plan was amended in January 2000, to increase the shares of common stock issuable from 250,000 to 500,000 for a period expiring in 2007. The 235,500 options outstanding as of December 31, 2001 under the plan have a term of ten years and an exercise price equal to the fair market value of the stock on the date of grant. The 1997 Plan provides that participants may be granted awards in the form of incentive stock options, non-qualified options as defined in the Code, stock appreciation rights ("SARs"), performance awards related to the Company's operations, or restricted stock. At December 31, 2001, a total of 264,500 shares were available for future grant.

The Company granted stock options in 2001 to employees that have contractual terms of 10 years and an exercise price equal to the fair market value of the stock at grant date. The options granted in 2001 vest one-third each year, beginning on the first anniversary of the date of grant. A summary of the status of the Company's stock options granted to employees as of December 31, 2001, December 31, 2000, September 30, 2000, and September 30, 1999 and the changes during the periods ended on those dates are presented below:

	# Shares of Underlying Options	Weighted Average Exercise Price	Weighted Average FV of All Options Granted
As of September 30, 1998	370,900	$3.84	
Granted in fiscal 1999	134,000	$2.24	$0.88
Forfeited in fiscal 1999	(12,000)	$2.81	
Exercised in fiscal 1999	-	-	
As of September 30, 1999	492,900	$3.43	
Granted in fiscal 2000	-	-	N/A
Forfeited in fiscal 2000	(12,000)	$3.25	
Exercised in fiscal 2000	(7,000)	$2.50	
As of September 30, 2000	473,900	$3.45	
Granted in transition period	10,000	$3.63	$2.12
Forfeited in transition period	(2,000)	$2.50	
Exercised in transition period	(2,000)	$2.50	
As of December 31, 2000	479,900	$3.46	
Granted in 2001	25,000	$3.37	$1.78
Forfeited in 2001	(5,000)	$4.56	
Exercised in 2001	-	-	
As of December 31, 2001	499,900	$3.44	
Exercisable as of December 31, 2001	456,568	$3.49	

The fair value of each stock option granted is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Year Ended September 30 2000	Fiscal Year Ended September 30 1999
Expected Term	3.0	8.8	10.0	7.8
Expected Volatility	76.57%	75.08%	72.07%	63.91%
Expected Dividend Yield	0.00%	0.00%	0.00%	0.00%
Risk-Free Interest Rate	4.71%	5.60%	6.45%	5.30%

The following table summarizes information about employee stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/01	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Contract Life	Number Exercisable at 12/31/01	Wgtd. Avg. Exercise Price
$1.50 to $2.00	35,000	$1.50	7.7	23,335	$1.50
$2.50 to $3.75	287,400	$3.01	4.7	255,733	$2.96
$4.00 to 5.13	177,500	$4.52	4.6	177,500	$4.52
$1.50 to $5.13	499,900	$3.44	4.9	456,568	$3.49

Warrants Issued to Employees and Directors

The Company granted warrants in 2001 to one employee with contractual terms of 10 years and an exercise price equal to the fair market value of the stock at grant date. The warrants granted in 2001 vest one-third each year, beginning on the first anniversary of the date of grant.

A summary of the status of the Company's warrants granted to employees and directors as of December 31, 2001, December 31, 2000, September 30, 2000 and September 30, 1999 and the changes during the periods ended on those dates are presented below:

	# Shares of Underlying Warrants	Weighted Average Exercise Price	Weighted Average FV of All Warrants Granted
As of September 30, 1998	456,900	$3.14	
Granted in fiscal 1999	250,000	$1.50	$1.19
Forfeited in fiscal 1999	-	-	
Exercised in fiscal 1999	-	-	
As of September 30, 1999	706,900	$2.56	
Granted in fiscal 2000	150,000	$1.88	$1.54
Forfeited in fiscal 2000	-	-	
Exercised in fiscal 2000	-	-	
As of September 30, 2000	856,900	$2.44	
Granted in transition period	50,000	$3.00	$2.44
Forfeited in transition period	-	-	
Exercised in transition period	-	-	
As of December 31, 2000	906,900	$2.47	
Granted in 2001	50,000	$3.75	$2.60
Forfeited in 2001	-	-	
Exercised in 2001	-	-	
As of December 31, 2001	956,900	$2.54	
Exercisable as of December 31, 2001	756,902	$2.55	

Assumption	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Year Ended September 30 2000	Fiscal Year Ended September 30 1999
Expected Term	8.0	8.8	10.0	7.8
Expected Volatility	61.90%	75.08%	72.07%	63.91%
Expected Dividend Yield	0.00%	0.00%	0.00%	0.00%
Risk-Free Interest Rate	5.29%	5.60%	6.45%	5.30%

The following table summarizes information about employee and director warrants outstanding at December 31, 2001:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/01	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Contract Life	Number Exercisable at 12/31/01	Wgtd. Avg. Exercise Price
$1.50 to $2.00	551,900	$1.68	5.0	468,568	$1.72
$2.50 to $3.75	200,000	$3.03	7.1	83,334	$2.78
$4.00 to $4.63	205,000	$4.36	5.0	205,000	$4.36
$1.50 to $4.63	956,900	$2.54	5.4	756,902	$2.55

Had compensation cost for the options and warrants awarded been determined based on the fair value at the grant dates consistent with the method of SFAS 123, the Company's net loss and loss per share would have been adjusted to the pro forma amounts indicated below:

		Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	Fiscal Years Ended September 30 1999
Net income (loss)	As Reported	$ (7,176,000)	$ (1,120,000)	$ 43,000	$ (9,295,000)
	Pro forma	$ (7,701,000)	$ (1,157,000)	$ (262,000)	$ (9,612,000)
Loss per share (basic)	As Reported	$ (.28)	$ (.05)	$ -	$ (.63)
	Pro forma	$ (.30)	$ (.05)	$ (.01)	$ (.65)

Non-Employee Compensatory Warrants

A summary of the status of the Company's warrants granted to non-employees as of December 31, 2001, December 31, 2000, September 30, 2000 and September 30, 1999 and the changes during the periods ended on those dates are presented below:

	# Shares of Underlying Warrants	Weighted Average Exercise Price	Weighted Average FV of All Warrants Granted
As of September 30, 1998	16,664	$3.63	
Granted in fiscal 1999	46,872	$2.76	$0.85
Forfeited in fiscal 1999	-	-	
Exercised in fiscal 1999	-	-	
As of September 30, 1999	63,536	$2.99	
Granted in fiscal 2000	25,000	$3.44	$0.77
Forfeited in fiscal 2000	-	-	
Exercised in fiscal 2000	-	-	
As of September 30, 2000	88,536	$3.12	
Granted in transition period	-	-	N/A
Forfeited in transition period	-	-	
Exercised in transition period	-	-	
As of December 31, 2000	88,536	$3.12	
Granted in 2001	-	-	N/A
Forfeited in 2001	(29,162)	$3.63	
Exercised in 2001	-	-	
As of December 31, 2001	59,374	$2.86	
Exercisable as of December 31, 2001	34,373	$2.79	

The fair value of each of the warrants granted to non-employees is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Year Ended September 30 2000	Fiscal Year Ended September 30 1999
Expected Term	8.0	8.8	10.0	7.8
Expected Volatility	61.90%	75.08%	72.07%	63.91%
Expected Dividend Yield	0.00%	0.00%	0.00%	0.00%
Risk-Free Interest Rate	4.79%	5.60%	6.45%	5.30%

The following table summarizes information about non-employee warrants outstanding at December 31, 2001:

	Warrants Outstanding			Warrants Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/01	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Contract Life	Number Exercisable at 12/31/01	Wgtd. Avg. Exercise Price
$1.50 to $2.00	25,000	$2.00	7.0	16,666	$2.00
$2.50 to $3.75	34,374	$3.49	8.1	17,707	$3.54
$1.50 to $3.75	59,374	$2.86	7.6	34,373	$2.79

NOTE 11 - INCOME TAXES

Under Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," the Company has recorded a $11.9 million asset for the future benefit of its net operating tax loss carryforwards and other tax benefits. As of December 31, 2001, this asset was offset by a valuation allowance of $11.9 million based on management's projection of realizability of the gross deferred tax asset.

The net deferred tax asset (in thousands) is comprised of the following:

	Year Ended December 31 2001	Three Months Ended December 31, 2000	Fiscal Year Ended September 30 2000
Australian properties:			
Deferred tax liabilities:			
Property, plant and equipment	$ (620)	$ (485)	$ (473)
Deferred tax assets:			
Net operating loss carry forwards	3,801	2,518	2,167
	3,181	2,033	1,694
Valuation allowance	(3,181)	(2,033)	(1,694)
Net deferred tax asset	$ -	$ -	$ -
United States properties:			
Deferred tax assets:			
Federal and state net operating loss carryforwards	$ 8,516	$ 6,923	$ 8,042
Statutory depletion carryforwards	2,548	2,648	2,499
Property, plant and equipment	592	859	1,345
Tax credit carryforwards	215	215	279
Other	1	1	2
	11,872	10,646	12,167
Valuation allowance	(11,872)	(10,646)	(12,167)
Net deferred tax asset	$ -	$ -	$ -

With the sale of a majority of the Company's U.S. producing properties in fiscal 2000 and its history of losses, management believes that sufficient uncertainty exists regarding the realizability of its net deferred tax asset. It therefore recorded a valuation allowance to offset the entire deferred tax asset at December 31, 2001 and 2000 and September 30, 2000. Management will continue to evaluate the Company's net deferred tax asset and to the extent management may determine that it is more likely than not that the asset will be realized, the valuation allowance will be reduced accordingly.

Income tax expense (benefit) is different than the expected amount computed using the applicable federal statutory income tax rate of 35%. With the Australian statutory income tax rate at the lower 30%, no additional income tax expense would result from foreign operations. The reasons for and effects of such differences (in thousands) are as follows:

	Year Ended December 31 2001	Three Months Ended December 31 2000	Fiscal Years Ended September 30 2000	Fiscal Years Ended September 30 1999
Expected amount	$ (2,511)	$ (392)	$ 437	$ (3,266)
Increase (decrease) from:				
Increase (decrease) in valuation allowance	2,375	(1,182)	(4,892)	(736)
Adjustments to and expiration of carryforwards	135	1,573	6,008	3,997
Permanent differences between financial statement income and taxable income	1	1	3	5
State taxes, net of federal benefit, and other	(1)	-	17	-
Total income tax expense (benefit)	$ (1)	$ -	$ 1,573	$ -

At December 31, 2001, the Company had U.S. net operating loss carryforwards of approximately $34 million to apply against future taxable income and $34 million to apply against future alternative minimum taxable income. Losses expire within 15-20 years after the date incurred or at various times from 2002 to 2022. With the change in accounting period discussed in Note 1, the carryforward periods were shortened by one year. Additionally, the Company has Australian loss carryforwards of approximately $13.7 million. The Australian losses can be carried forward indefinitely.

The Company also has statutory depletion carryforwards and minimum tax credit carryforwards which do not expire. The Company's U.S. net operating loss carryforwards would be subject to an annual limitation should there be a change of over 50% in the stock ownership of the Company during any three-year period. As of December 31, 2001, no such ownership change had occurred.

NOTE 12 - COMMITMENTS AND CONTINGENCIES

The Company is plaintiff in a lawsuit filed on August 6, 1998, styled *Tipperary Corporation and Tipperary Oil & Gas (Australia) Pty Ltd v. Tri-Star Petroleum Company*, Cause No. CV42,265, in the District Court of Midland County, Texas involving the Comet Ridge project. By amended petition filed May 1, 2000, Tipperary Oil & Gas Corporation joined the action as a plaintiff, along with the already-named plaintiffs and two unaffiliated non-operating working interest owners who previously intervened in the action as plaintiffs. James H. Butler, Sr., and James H. Butler, Jr., owners of defendant Tri-Star Petroleum Company, were also named as defendants in the amended petition. The Company and the other plaintiffs allege, among other matters, that Tri-Star and/or the individual defendants have failed to operate the properties in a good and workmanlike manner and have committed various other breaches of a joint operating contract, have breached a previous mediation agreement between the parties, have committed certain breaches of fiduciary and other duties owed to the plaintiffs, and have committed fraud in connection with the project. Tri-Star has answered the amended petition, and on December 22, 2000, Tri-Star filed its first amended counterclaim alleging tortious interference with the contracts, with the authority to prospect covering the project and with contractual relationships with vendors; commercial disparagement; foreclosure of operator's lien and alternatively forfeiture of undeveloped acreage; unjust enrichment and declaratory relief. As of February 8, 2001, the court enjoined Tri-Star from asserting any forfeiture claims based upon events prior to that date. On March 11, 2002, the court entered a Writ of Temporary Injunction, and an Amended Writ of Temporary Injunction on March 13, 2002, to enforce the votes of a majority-in-interest of the parties under the joint operating agreement to remove Tri-Star as operator and replace it with TOGA. The orders provided that TOGA take over operations on March 22, 2002. On March 15, 2002, Tri-Star filed a Notice of Accelerated Appeal of the March 11, 2002 Order Granting Injunctive Relief Regarding Removal of Tri-Star Petroleum Company as Operator. The lower court denied Tri-Star's request for a stay of enforcement of the injunctive orders. Tri-Star sought a stay from the Court of Appeals, which was likewise denied. TOGA has assumed operation of the Comet Ridge project under the terms of the orders. An evidentiary hearing relating to the May 2, 1996 Mediation Agreement between the parties and the obligation of the parties to arbitrate audit disputes is presently scheduled to begin on April 3, 2002. A trial on the merits is presently scheduled for April 29, 2002, although the prosecution of an appeal of the injunctive orders may delay the commencement of the trial.

Through December 31, 2001, the Company has made payments totaling approximately $1.1 million into the registry of the court for disputed portions of joint interest billings from Tri-Star. At the appropriate time, the court will determine the disposition of the funds paid into its registry. The funds may be returned to the Company, in whole or in part, or awarded to Tri-Star in whole or in part. If, and to the extent funds are returned, the Company will reduce its full cost pool for recovered capital costs and will record a gain for recovered operating costs. If, and to the extent funds are awarded to Tri-Star, the Company will not record an additional loss.

In 1997, the Company filed a complaint along with ten other plaintiffs in *BTA Oil Producers, et al. v. MDU Resources Group, Inc.* in Stark County Court in the Southwest Judicial District of North Dakota. The plaintiffs include major integrated oil companies (such as ExxonMobil Corporation) and agricultural cooperatives (Cenex Harvest States Cooperatives), as well as independent oil and gas producers such as the Company. The plaintiffs brought the action against the defendants for breach of gas sales contracts and processing agreements, unjust enrichment, implied trust and related business torts. The case concerns the sale by plaintiffs and certain predecessors of natural gas processed at the McKenzie Gas Processing Plant in North Dakota to Koch Hydrocarbons Company. It also concerns the contracts for resale of that gas to MDU Resources Group, Inc. and Williston Basin Interstate Pipeline Company. After the complaint was answered, the defendants moved for summary judgment against the plaintiffs. The trial court has entered two orders deciding the issues in the case. The plaintiffs prevailed on some issues, and the defendants prevailed on other issues. The parties are discussing the form of a judgment to submit to the trial court for entry. The parties anticipate an appeal after the judgment is entered.

Other Commitments and Contingencies

The Company has various commitments in addition to its long-term debt. The following table summarizes the Company's contractual obligations at December 31, 2001 (in thousands):

Contractual Obligation	Total	2002	2003	2004	2005	Thereafter
Long-term debt(1)	$ 14,414	$ 2,231	$ 4,063	$ 4,316	$ 3,804	$ -
Operating leases for office space	$ 855	$ 311	$ 311	$ 207	$ 26	$ -

(1) Principal payments on the TCW debt are due quarterly in an amount equal to the greater of a percentage of TOGA's operating cash flow as defined or a scheduled minimum principal payment. The payment amount in 2002 is based on the Company's projection for operating cash flow. Payments thereafter on the TCW debt are based on the scheduled minimum principal payment.

Principal payments on the Slough debt are due monthly and are based on the projected rental payments expected from the drilling contractor during 2002.

The Company's business activities are subject to federal, state and local environmental laws and regulations as well as similar laws and regulations in the Commonwealth of Australia and in the State of Queensland, Australia. The existence of these regulations has had no material effect on the Company's operations and the cost of such compliance has not been material to date. The Company will continue to monitor environmental compliance. There can be no assurance that environmental laws and regulations will not become more stringent in the future or that the Company will not incur significant costs in the future to comply with such laws and regulations.

The Company is subject to various other possible contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the oil and gas industry. Although management believes it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

NOTE 13 - OPERATIONS BY GEOGRAPHIC AREA

The Company has one operating and reporting segment - oil and gas exploration, development and production - located in the United States and Australia. Information about the Company's operations by geographic area is shown below (in thousands):

	Australia	United States	Total
Year ended December 31, 2001:			
Revenues	$ 2,646	$ 911	$ 3,557
Property, plant and equipment, net	$ 45,270	$ 9,152	$ 54,422
Three months ended December 31, 2000:			
Revenues	$ 525	$ 339	$ 864
Property, plant and equipment, net	$ 39,618	$ 6,882	$ 46,500
Fiscal year ended September 30, 2000:			
Revenues	$ 2,033	$ 6,591	$ 8,624
Property, plant and equipment, net	$ 37,771	$ 4,434	$ 42,205
Fiscal year ended September 30, 1999:			
Revenues	$ 1,191	$ 6,730	$ 7,921
Property, plant and equipment, net	$ 27,686	$ 15,636	$ 43,322

NOTE 14 - SUPPLEMENTARY INFORMATION ON OIL AND GAS OPERATIONS

Certain historical cost and operating information relating to the Company's oil and gas producing activities are as follows:

CAPITALIZED COSTS:

	Australia	United States	Total
December 31, 2001:			
Proved oil and gas properties	$ 42,381	$ 23,511	$ 65,892
Unproved oil and gas properties	2,340	5,773	8,113
	44,721	29,274	74,005
Less accumulated DD&A	(2,144)	(20,277)	(22,421)
Net capitalized costs	$ 42,577	$ 9,007	$ 51,584
December 31, 2000:			
Proved oil and gas properties	$ 39,333	$ 23,298	$ 62,631
Unproved oil and gas properties	1,660	3,542	5,202
	40,993	26,840	67,833
Less accumulated DD&A	(1,404)	(20,074)	(21,478)
Net capitalized costs	$ 39,589	$ 6,766	$ 46,355
September 30, 2000:			
Proved oil and gas properties	$ 38,166	$ 21,664	$ 59,830
Unproved oil and gas properties	842	2,670	3,512
	39,008	24,334	63,342
Less accumulated DD&A	(1,258)	(20,007)	(21,265)
Net capitalized costs	$ 37,750	$ 4,327	$ 42,077
September 30, 1999:			
Proved oil and gas properties	$ 27,972	$ 100,587	$ 128,559
Unproved oil and gas properties	317	7,686	8,003
	28,289	108,273	136,562
Less accumulated DD&A	(610)	(93,212)	(93,822)
Net capitalized costs	$ 27,679	$ 15,061	$ 42,740

COSTS INCURRED:

	Australia	United States	Total
Year ended December 31, 2001:			
Property acquisition costs:			
Proved oil and gas properties	$ 3,016	$ -	$ 3,016
Unproved oil and gas properties	-	5,202	5,202
	3,016	5,202	8,218
Exploration costs	1,062	1,173 (2)	2,235
Capitalized interest costs	-	286	286
Development costs (1)	5,930	833	6,763
Total costs incurred	$ 10,008	$ 7,494	$ 17,502
Three months ended December 31, 2000:			
Property acquisition costs:			
Proved oil and gas properties	$ -	$ -	$ -
Unproved oil and gas properties	19	872	891
	19	872	891
Exploration costs	799	1,599	2,398
Development costs (1)	1,167	35	1,202
Total costs incurred	$ 1,985	$ 2,506	$ 4,491
Fiscal year ended September 30, 2000:			
Property acquisition costs:			
Proved oil and gas properties	$ 6,211	$ 3	$ 6,214
Unproved oil and gas properties	145	1,281	1,426
	6,356	1,284	7,640
Exploration costs	381	585	966
Development costs (1)	3,982	401	4,383
Total costs incurred	$ 10,719	$ 2,270	$ 12,989
September 30, 1999:			
Property acquisition costs:			
Proved oil and gas properties	$ 13	$ 232	$ 245
Unproved oil and gas properties	15	57	72
	28	289	317
Exploration costs	302	33	335
Development costs (1)	5,319	376	5,695
Total costs incurred	$ 5,649	$ 698	$ 6,347

(1) Costs to develop proved undeveloped reserves included in the standardized measure of discounted future net cash flows in Australia and incurred during 2001, the three-months ended December 31, 2000 and fiscal 2000 and 1999 were $3,890,000, $207,000, $3,104,000 and $2,960,000, respectively. Costs incurred of $804,000 and $24,000 were associated with domestic proved undeveloped reserves in 2001 and fiscal 2000, respectively.

(2) Includes $729,000 in costs reimbursed by Koch Exploration Company.

The depletion rate for 2001 and the three months ended December 31, 2000 were $0.95 and $1.30 per equivalent Mcf of domestic production, respectively. Depletion rates per equivalent barrel of domestic production for fiscal 2000 and 1999 were $4.66 and $4.51, respectively. Costs of $5,490,000, $2,173,000, $1,301,000 and $2,122,000 related to domestic unproved oil and gas properties pending evaluation were excluded from depletable costs in 2001, the three months ended December 31, 2000 and fiscal 2000 and 1999, respectively.

The rates of depletion per Mcf of production in Australia were $0.25 for 2001, $0.23 for the three months ended December 31, 2000, $0.29 for fiscal 2000 and $0.30 for fiscal 1999. Excluded from depletable costs are costs of $2,350,000 in 2001, $476,000 in the three months ended December 31, 2000, $461,000 in fiscal 2000 and $317,000 in fiscal 1999 related to Australian properties that have not yet been evaluated.

RESULTS OF OPERATIONS (UNAUDITED):

The results of operations for petroleum producing activities, excluding corporate overhead and interest costs, (in thousands) are as follows:

	Australia	United States	Total
Year ended December 31, 2001:			
Revenue from sale of oil and gas	$ 2,606	$ 902	$ 3,508
Production costs	(1,508)	(832)	(2,340)
Depreciation, depletion and amortization, including impairment	(740)	(203)	(943)
Income tax expense[1]	-	1	1
Operating income (loss) from petroleum producing activities	$ 358	$ (132)	$ 226
Three months ended December 31, 2000:			
Revenue from sale of oil and gas	$ 525	$ 281	$ 806
Production costs	(385)	(72)	(457)
Depreciation, depletion and amortization, including impairment	(146)	(67)	(213)
Income tax expense[1]	-	-	-
Operating income (loss) from petroleum producing activities	$ (6)	$ 142	$ 136
Fiscal year ended September 30, 2000:			
Revenue from sale of oil and gas	$ 2,033	$ 6,500	$ 8,533
Production costs	(1,405)	(2,835)	(4,240)
Depreciation, depletion and amortization, including impairment	(1,205)	(1,225)	(2,430)
Gain on sale of oil and gas properties	-	4,837[2]	4,837
Income tax expense[1]	-	-	-
Operating income (loss) from petroleum producing activities	$ (577)	$ 7,277	$ 6,700
Fiscal year ended September 30, 1999:			
Revenue from sale of oil and gas	$ 1,191	$ 6,620	$ 7,811
Production costs	(870)	(3,846)	(4,716)
Depreciation, depletion and amortization, including impairment	(415)	(8,203)	(8,618)
Income tax expense[1]	-	-	-
Operating loss from petroleum producing activities	$ (94)	$ (5,429)	$ (5,523)

(1) Income tax expense is computed using the Company's overall effective tax rate for each respective year and takes into consideration the Company's net operating loss carryforwards.

(2) See Note 3.

ESTIMATES OF PROVED OIL AND GAS RESERVES (UNAUDITED):

The following table presents the Company's estimates of its proved oil and gas reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of mature producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. Reserve estimates are prepared by independent petroleum engineers: Holditch-Reservoir Technologies Consulting Services, a division of Schlumberger Technology Corporation, for Australia properties; and Garb, Grubbs, Harris & Associates, Inc. for U.S. properties.

	Australia		United States		Total	
	Oil MBbls	Gas MMcf	Oil MBbls	Gas MMcf	Oil MBbls	Gas MMcf
Year ended December 31, 2001:						
Total proved reserves:						
Beginning of year	-	265,521	324	2,470	324	267,991
Revisions of previous estimates	-	(33,023)	(27)	(87)	(27)	(33,110)
Extensions and discoveries	-	58,900	27	186	27	59,086
Purchases of reserves in place	-	14,200	-	-	-	14,200
Sale of reserves in place	-	(22,600)	-	-	-	(22,600)
Production	-	(3,325)	(17)	(100)	(17)	(3,425)
End of year	-	279,673[(1)]	307	2,469	307	282,142
Proved developed reserves:						
Beginning of year	-	49,969	140	1,268	140	51,237
End of year	-	62,481[(1)]	198	1,775	198	64,256
Three months ended December 31, 2000:						
Total proved reserves:						
Beginning of period	-	265,125	379	2,924	379	268,049
Revisions of previous estimates	-	1,018	(52)	(423)	(52)	595
Extensions and discoveries	-	-	-	-	-	-
Purchases of reserves in place	-	-	-	-	-	-
Sale of reserves in place	-	-	-	-	-	-
Production	-	(622)	(3)	(31)	(3)	(653)
End of period	-	265,521[(2)]	324	2,470	324	267,991
Proved developed reserves						
October 1, 2000	-	50,231	170	1,563	170	51,794
December 31, 2000	-	49,969[(2)]	140	1,268	140	51,237
Fiscal year ended September 30, 2000:						
Total proved reserves:						
Beginning of year	-	131,273	2,455	9,803	2,455	141,076
Revisions of previous estimates	-	14,250	30	224	30	14,474
Extensions and discoveries	-	104,138	5	32	5	104,170
Purchases of reserves in place	-	17,665	-	-	-	17,665
Sale of reserves in place	-	-	(1,919)	(6,424)	(1,919)	(6,424)
Production	-	(2,201)	(192)	(711)	(192)	(2,912)
End of year	-	265,125[(3)]	379	2,924	379	268,049
Proved developed reserves:						
Beginning of year	-	30,899	2,171	8,003	2,171	38,902
End of year	-	50,231[(3)]	170	1,563	170	51,794
Fiscal year September 30, 1999:						
Total proved reserves:						
Beginning of year	-	122,509	2,388	9,023	2,388	131,532
Revisions of previous estimates	-	10,130	346	1,879	346	12,009
Extensions and discoveries	-	-	26	46	26	46
Purchases of reserves in place	-	-	47	38	47	38
Sale of reserves in place	-	-	-	-	-	-
Production	-	(1,366)	(352)	(1,183)	(352)	(2,549)
End of year	-	131,273[(4)]	2,455	9,803	2,455	141,076
Proved developed reserves:						
Beginning of year	-	28,100	2,114	7,255	2,114	35,355
End of year	-	30,899[(4)]	2,171	8,003	2,171	38,902

[(1)] Includes 27,967 MMcf of total proved reserves and 6,248 MMcf of proved developed reserves attributable to the 10% minority interest held by Slough in TOGA.

[(2)] Includes 26,552 MMcf of total proved reserves and 4,997 MMcf of proved developed reserves attributable to the 10% minority interest held by Slough in TOGA.

(3) Includes 26,513 MMcf of total proved reserves and 5,023 MMcf of proved developed reserves attributable to the 10% minority interest held by Slough in TOGA.

(4) Includes 13,127 MMcf of total proved reserves and 3,090 MMcf of proved developed reserves attributable to the 10% minority interest held by Slough in TOGA.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED):

Information with respect to the Company's estimated discounted future net cash flows from its oil and gas properties is as follows (in thousands):

	Australia	United States	Total
December 31, 2001:			
Future revenues	$ 453,627	$ 16,443	$ 470,070
Future production costs[1]	(75,331)	(3,441)	(78,772)
Future development costs	(40,489)	(1,259)	(41,748)
Future income tax expense[2]	(95,588)	(20)	(95,608)
Future net cash flow	242,219	11,723	253,942
10% annual discount	(170,195)	(5,864)	(176,059)
Discounted future net cash flows	$ 72,024[3]	$ 5,859	$ 77,883
December 31, 2000:			
Future revenues	$ 326,696	$ 33,782	$ 360,478
Future production costs	(66,221)	(5,213)	(71,434)
Future development costs	(23,266)	(1,060)	(24,326)
Future income tax expense[2]	(75,604)	(517)	(76,121)
Future net cash flow	161,605	26,992	188,597
10% annual discount	(91,907)	(11,778)	(103,685)
Discounted future net cash flows	$ 69,698[3]	$ 15,214	$ 84,912
September 30, 2000:			
Future revenues	$ 316,652	$ 27,175	$ 343,827
Future production costs	(65,345)	(5,348)	(70,693)
Future development costs	(23,424)	(1,060)	(24,484)
Future income tax expense[2]	(72,867)	(423)	(73,290)
Future net cash flow	155,016	20,344	175,360
10% annual discount	(89,321)	(10,165)	(99,486)
Discounted future net cash flows	$ 65,695[3]	$ 10,179	$ 75,874
September 30, 1999:			
Future revenues	$ 177,744	$ 78,534	$ 256,278
Future production costs	(33,032)	(35,079)	(68,111)
Future development costs	(13,054)	(1,490)	(14,544)
Future income tax expense[2]	(39,575)	(5,362)	(44,937)
Future net cash flow	92,083	36,603	128,686
10% annual discount	(51,928)	(14,295)	(66,223)
Discounted future net cash flows	$ 40,155[3]	$ 22,308	$ 62,463

(1) Total future development costs expected to be incurred during 2002, 2003 and 2004 total $600,000 in the United States and $9.7 million in Australia.

(2) Income tax expense is computed using the Company's overall effective tax rate for each respective year and takes into consideration the Company's net operating loss carryforwards.

(3) Ten percent of the discounted future net cash flows are attributable to the minority interest held by Slough in TOGA.

Principal changes in the Company's estimated discounted future net cash flows (in thousands) are as follows:

	Australia	United States	Total
Year ended December 31, 2001:			
Beginning of period	$ 69,698	$ 15,214	$ 84,912
Oil and gas sales, net of production costs	(1,098)	(70)	(1,168)
Net change in prices and production costs	(9,319)	(9,744)	(19,063)
Extensions and discoveries, less related costs	9,356	84	9,440
Sales of reserves in place	(5,914)	-	(5,914)
Purchases of reserves in place	3,727	-	3,727
Development costs incurred	3,890	804	4,694
Change in estimated development costs	5	249	254
Revision of previous quantity estimates	(8,668)	(854)	(9,522)
Accretion of discount	6,970	1,521	8,491
Net change in income taxes	(5,747)	249	(5,498)
Changes in production rates and other	9,124	(1,594)	7,530
End of period	$ 72,024[(1)]	$ 5,859	$ 77,883

At December 31, 2001, period-end oil and gas prices used in the determination of future cash flows for domestic reserves were $19.84 per barrel and $2.57 per Mcf, respectively. The weighted average gas contractual price used in the determination of future cash flows for Australia reserves was U.S. $1.62 per Mcf.

(1) Includes approximately $7,202,000 attributable to the 10% minority interest held by Slough in TOGA.

	Australia	United States	Total
Three months ended December 31, 2000:			
Beginning of period	$ 65,695	$ 10,179	$ 75,874
Oil and gas sales, net of production costs	(140)	(209)	(349)
Net change in prices and production costs	4,737	8,063	12,800
Extensions and discoveries, less related costs	-	-	-
Sales of reserves in place	-	-	-
Purchases of reserves in place	-	-	-
Development costs incurred	207	-	207
Change in estimated development costs	1,152	(11)	1,141
Revision of previous quantity estimates	509	(1,438)	(929)
Accretion of discount	1,642	254	1,896
Net change in income taxes	(1,878)	(83)	(1,961)
Changes in production rates and other	(2,226)	(1,541)	(3,767)
End of period	$ 69,698[(1)]	$ 15,214	$ 84,912

At December 31, 2000, period-end oil and gas prices used in the determination of future cash flows for domestic reserves were $25.70 per barrel and $10.31 per Mcf, respectively. The gas price used in the determination of future cash flows for Australia reserves was U.S. $1.23 per Mcf.

(1) Includes approximately $6,970,000 attributable to the 10% minority interest held by Slough in TOGA.

	Australia	United States	Total
Fiscal year ended September 30, 2000:			
Beginning of year	$ 40,155	$ 22,308	$ 62,463
Oil and gas sales, net of production costs	(628)	(3,588)	(4,216)
Net change in prices and production costs	(3,321)	5,452	2,131
Extensions and discoveries, less related costs	32,876	81	32,957
Sales of reserves in place	-	(17,416)	(17,416)
Purchases of reserves in place	8,028	-	8,028
Development costs incurred	3,104	24	3,128
Change in estimated development costs	(9,064)	(254)	(9,318)
Revision of previous quantity estimates	4,368	367	4,735
Accretion of discount	4,016	2,231	6,247
Net change in income taxes	(12,349)	2,604	(9,745)
Changes in production rates and other	(1,490)	(1,630)	(3,120)
End of year	$ 65,695(2)	$ 10,179	$ 75,874

At September 30, 2000, year-end oil and gas prices used in the determination of future cash flows for domestic reserves were $27.47 per barrel and $5.74 per Mcf, respectively. The gas price used in the determination of future cash flows for Australia reserves was U.S. $1.19 per Mcf.

(2) Includes approximately $6,570,000 attributable to the 10% minority interest held by Slough in TOGA.

	Australia	United States	Total
Fiscal year ended September 30, 1999:			
Beginning of year	$ 30,680	$ 16,176	$ 46,856
Oil and gas sales, net of production costs	(321)	(2,897)	(3,218)
Net change in prices and production costs	3,466	7,179	10,645
Extensions and discoveries, less related costs	-	192	192
Purchases of reserves in place, net	-	341	341
Sale of reserves in place	-	-	-
Development costs incurred	2,960	-	2,960
Change in estimated development costs	(254)	67	(187)
Revision of previous quantity estimates	2,533	2,743	5,276
Accretion of discount	3,068	1,618	4,686
Net change in income taxes	(1,590)	(2,239)	(3,829)
Changes in production rates and other	(387)	(872)	(1,259)
End of year	$ 40,155(3)	$ 22,308	$ 62,463

At September 30, 1999, year-end oil and gas prices used in the determination of future cash flows for domestic reserves were $22.08 per barrel and $2.48 per Mcf, respectively. The gas price used in the determination of future cash flows for Australia reserves as U.S. $1.35 per Mcf.

(3) Includes approximately $4,016,000 attributable to the 10% minority interest held by Slough in TOGA.

NOTE 15 - QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a summary of the unaudited quarterly results of operations (in thousands, except per share data):

	Quarter Ended				
	March 31 2001	June 30 2001	September 30 2001	December 31 2001	Total
Year ended December 31, 2001					
Revenues	$ 869	$ 772	$ 881	$ 1,035	$ 3,557
Gross profit(1)	$ 407	$ 116	$ 381	$ 435	$ 1,339
Net income (loss)	$ (1,195)	$ (1,797)	$ (1,590)	$ (2,594)(2)	$ (7,176)
Net income (loss) per common share:					
- basic	$ (.05)	$ (.07)	$ (.06)	$ (.09)	$ (.28)
- diluted	$ (.05)	$ (.07)	$ (.06)	$ (.09)	$ (.28)

	Quarter Ended				
	December 31 1999	March 31 2000	June 30 2000	September 30 2000	Total
Fiscal year ended September 30, 2000					
Revenues	$ 2,919	$ 3,016	$ 1,811	$ 878	$ 8,624
Gross profit(1)	$ 1,590	$ 1,602	$ 777	$ 422	$ 4,391
Net income (loss)	$ (306)	$ (311)	$ 2,109(3)	$ (1,449)(2)	$ 43
Net income (loss) per common share:					
- basic	$ (.02)	$ (.01)	$ .09	$ (.06)	$ -
- diluted	$ (.02)	$ (.01)	$ .08	$ (.06)	$ -

(1) Includes revenue less operating expense and excludes DD&A.

(2) Includes a non-cash write-down of prepaid drilling costs of $900,000 and $557,000 in the fourth quarter of 2001 and 2000, respectively. See Note 7.

(3) Includes a $4,973,000 gain on sale of U.S. oil and gas properties.

ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS; COMPLIANCE WITH SECTION 16(a) OF THE EXCHANGE ACT

The information under the captions, "Proposal 1, Election of Directors," "Executive Officers" and "Compliance with Section 16(a) of the Exchange Act" in the Company's definitive Proxy Statement in connection with the 2001 annual stockholders' meeting is incorporated herein by reference.

ITEM 10. EXECUTIVE COMPENSATION

The information under the captions "Executive Compensation," "Employment Agreements" and "Compensation of Directors" in the definitive Proxy Statement is incorporated herein by reference.

ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information under the captions "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Management" in the definitive Proxy Statement is incorporated herein by reference.

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRASACTIONS

The information under the caption "Certain Relationships and Related Transactions" in the definitive Proxy Statement is incorporated herein by reference.

ITEM 13. EXHIBITS AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of the report:

For a list of financial statements and financial statement schedules, see "Index to Consolidated Financial Statements" on page 23.

(b) On October 18, 2001 the Company filed a Current Report on Form 8-K disclosing under "Item 5. Other Events," Exhibits 4.72, 4.73, 10.81 and 10.82 listed and described below.

(c) Exhibits:

For a list of exhibits, see "Exhibits" on page 55, which list is incorporated herein by reference.

EXHIBITS

Numbers	Description
3.9	Restated Articles of Incorporation of Tipperary Corporation adopted May 6, 1993, filed as Exhibit 3.9 to Amendment No. 1 to Registration Statement on Form S-1 filed with the Commission on June 29, 1993, and incorporated herein by reference.
3.10	Restated Corporate Bylaws of Tipperary Corporation adopted June 28, 1993, filed as Exhibit 3.10 to Amendment No. 1 to Registration Statement on Form S-1 filed with the Commission on June 29, 1993, and incorporated herein by reference.
3.11	Articles of Amendment of the Articles of Incorporation of Tipperary Corporation adopted January 25, 2000, filed as Exhibit 3.11 to Form 10-QSB for the quarterly period ended December 31, 1999, and incorporated herein by reference.
3.12	Statement of Resolution Establishing a Series of Shares dated December 23, 1999, filed as Exhibit 3.12 to Form 10-QSB for the quarterly period ended December 31, 1999, and incorporated herein by reference.
4.59	Loan Agreement Promissory Note dated December 22, 1998, in the amount of $6,000,000 between Registrant and Slough Estates USA Inc., filed as Exhibit 4.59 to Form 10-Q for the quarterly period ended December 31, 1998 and incorporated herein by reference.
4.60	Security Agreement dated December 22, 1998, between the Registrant and Slough Estates USA Inc., filed as Exhibit 4.60 to Form 10-Q for the quarterly period ended December 31, 1998, and incorporated herein by reference.
4.61	Pledge of Stock dated December 22, 1998, between the Registrant and Slough Estates USA Inc., filed as Exhibit 4.61 to Form 10-Q for the quarterly period ended December 31, 1998, and incorporated herein by reference.
4.66	Credit Agreement among Tipperary Corporation as Borrower, Tipperary Oil & Gas (Australia) Pty Ltd (ACN 077536871) as Guarantor, Tipperary Oil & Gas Corporation, Lenders party thereto and TCW Asset Management Company in the capacities described therein dated as of April 28, 2000, filed as Exhibit 4.66 to Form 10-QSB for the quarterly period ended June 30, 2000, and incorporated herein by reference.
4.67	Promissory Note dated December 19, 2000, in the amount of $7,500,000 issued by Registrant to Slough Estates USA Inc., filed as Exhibit 4.67 to Form 10-KSB(A) for the transition period ended December 31, 2000, and incorporated herein by reference.
4.68	Second Amendment to Security Agreement dated December 19, 2000, between the Registrant and Slough Estates USA Inc., filed as Exhibit 4.68 to Form 10-KSB(A) for the transition period ended December 31, 2000, and incorporated herein by reference.
4.69	Promissory Note dated March 6, 2001, in the amount of $12,000,000 issued by Registrant to Slough Estates USA Inc., filed as Exhibit 4.69 to Form 10-QSB(A) for the quarterly period ended March 31, 2001, and incorporated herein by reference.
4.70	Fourth Amendment to Security Agreement dated March 6, 2001, between the Registrant and Slough Estates USA Inc., filed as Exhibit 4.70 to Form 10-QSB(A) for the quarterly period ended March 31, 2001, and incorporated herein by reference.

Number	Description
4.71	First Amended and Restated Credit Agreement among Tipperary Corporation as Borrower, Tipperary Oil & Gas (Australia) Pty Ltd (ACN 077536871) as Guarantor, Tipperary Oil & Gas Corporation, Lenders party thereto and TCW Asset Management Company in the capacities described therein dated as of February 20, 2001, filed as Exhibit 4.71 to Form 10-QSB(A) for the quarterly period ended March 31, 2001, and incorporated herein by reference.
4.72	Promissory Note dated August 20, 2001, in the amount of $15,000,000 issued by the Registrant to Slough Estates USA Inc., filed as Exhibit 4.72 to Form 8-K filed with the Commission on October 18, 2001, and incorporated herein by reference.
4.73	First Amendment to Security Agreement dated August 20, 2001, between the Registrant and Slough Estates USA Inc., filed as Exhibit 4.73 to Form 8-K filed with the Commission on October 18, 2001, and incorporated herein by reference.
10.51	Tipperary Corporation 1997 Long-Term Incentive Plan filed as Exhibit A to the Registrant's Proxy Statement for its Annual Meeting of Shareholders held on January 28, 1997, filed as Exhibit 10.51 to Form 10-Q dated December 31, 1996, and incorporated herein by reference.
10.58	Warrant to Purchase the Registrant's common stock dated December 22, 1998, issued to Slough Estates USA Inc., filed as Exhibit 10.58 to Form 10-Q for the quarterly period ended December 31, 1998, and incorporated herein by reference.
10.59	Subscription Agreement to purchase Registrant's common stock dated December 22, 1998, between Registrant and Slough Estates USA Inc., filed as Exhibit 10-59 to Form 10-Q for the quarterly period ended December 31, 1998, and incorporated herein by reference.
10.60	Warrant to Purchase the Registrant's common stock dated December 23, 1999, issued to Slough Estates USA Inc., filed as Exhibit 10.60 to Form 10-QSB for the quarterly period ended December 31, 1999, and incorporated herein by reference.
10.61	Registration Rights Agreement between Tipperary Corporation and Slough Estates USA Inc., dated December 23, 1999, filed as Exhibit 10.61 to Form 10-QSB for the quarterly period ended December 31, 1999, and incorporated herein by reference.
10.62	Purchase and Sale Agreement dated January 14, 2000, between Ray W. Williams as Seller and Tipperary Corporation as Buyer, filed as Exhibit 10.62 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.63	Purchase and Sale Agreement dated January 14, 2000, between William I. Isaac as Seller and Tipperary Corporation as Buyer, filed as Exhibit 10.63 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.64	Purchase and Sale Agreement dated February 11, 2000, between William D. Kennedy as Seller and Tipperary Corporation as Buyer, filed as Exhibit 10.64 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.65	Registration Rights Agreement between Tipperary Corporation and Ray W. Williams, dated February 10, 2000, filed as Exhibit 10.65 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.66	Registration Rights Agreement between Tipperary Corporation and William I. Isaac, dated February 10, 2000, filed as Exhibit 10.66 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.

Number	Description
10.67	Registration Rights Agreement between Tipperary Corporation and William D. Kennedy, dated February 11, 2000, filed as Exhibit 10.67 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.68	Registration Rights Agreement between Tipperary Corporation and James H. Marshall, dated February 9, 2000, filed as Exhibit 10.68 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.69	Registration Rights Agreement between Tipperary Corporation and James F. Knott, dated February 9, 2000, filed as Exhibit 10.69 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.70	Warrant to Purchase the Registrant's common stock dated February 9, 2000, issued to James H. Marshall, filed as Exhibit 10.70 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.71	Warrant to Purchase the Registrant's common stock dated February 9, 2000, issued to James F. Knott, filed as Exhibit 10.71 to Form 10-QSB for the quarterly period ended March 31, 2000, and incorporated herein by reference.
10.72	Purchase and Sale Agreement dated April 12, 2000, between Tipperary Oil & Gas Corporation as Seller and Nance Petroleum Corporation as Buyer, filed as Exhibit 10.72 to Form 8-K dated May 18, 2000, and incorporated herein by reference.
10.73	Purchase and Sale Agreement dated July 21, 2000, between Elisa A. Stoner as Seller and Tipperary Corporation as Buyer, filed as Exhibit 10.73 to Form 10-QSB for the quarterly period ended June 30, 2000, and incorporated herein by reference.
10.74	Registration Statement Agreement between Tipperary Corporation and Elisa A. Stoner dated July 21, 2000, filed as Exhibit 10.74 to Form 10-QSB for the quarterly period ended June 30, 2000, and incorporated herein by reference.
10.75	Purchase and Sale Agreement dated June 14, 2000, between Tipperary Oil & Gas Corporation as Seller, and Transrepublic Resources as Buyer, filed as Exhibit 10.75 to Form 10-QSB for the quarterly period ended June 30, 2000, and incorporated herein by reference.
10.76	Gas Supply Agreement between Tipperary Oil & Gas (Australia) Pty Ltd (ACN 077 536 871) and ENERGEX Retail Pty Ltd (ACN 078 849 055) dated June 23, 2000, filed as Exhibit 10.76 to Form 10-QSB for the quarterly period ended June 30, 2000, and incorporated herein by reference.
10.77	Warrant to Purchase the Registrant's common stock dated May 3, 2000, issued to Charles T. Maxwell filed as Exhibit 10.77 to Form 10-KSB(A) for the transition period ended December 31, 2000, and incorporated herein by reference.
10.78	Warrant to Purchase the Registrant's common stock dated June 29, 2000, issued to Richard Barber filed as Exhibit 10.78 to Form 10-KSB(A) for the transition period ended December 31, 2000, and incorporated herein by reference.
10.79	Warrant to Purchase the Registrant's common stock dated November 30, 2000, issued to D. Leroy Sample, filed as Exhibit 10.79 to Form 10-KSB(A) for the transition period ended December 31, 2000, and incorporated herein by reference.
10.80	Purchase and Sale Agreement dated May 4, 2001, by and between Tipperary Oil & Gas Corporation and Koch Exploration Company, filed as Exhibit 10.80 to Form S-3, SEC File No. 333-59052, filed with the Commission on July 26, 2001, and incorporated herein by reference.

Number	Description
10.81	Gas Sales Agreement between Tipperary Oil & Gas (Australia) Pty Ltd (ACN 077 536 871) as Seller and Queensland Fertilizer Assets Limited (ACN 011 062 294) as Buyer, dated September 28, 2001, filed as Exhibit 10.81 to Form 8-K filed with the Commission on October 18, 2001, and incorporated herein by reference.
10.82	Employment Agreement dated September 18, 2001 between Registrant and David L. Bradshaw, filed as Exhibit 10.82 to Form 8-K filed with the Commission on October 18, 2001, and incorporated herein by reference.
10.83	Warrant to Purchase the Registrant's common stock dated January 30, 2002, issued to Jeff T. Obourn, filed herewith.
21.1	List of subsidiaries, filed herewith.
23.1	Consent of PricewaterhouseCoopers LLP, filed herewith.
99.1	"Risk Factors" discussion from Registration Statement on Form S-3, SEC File No. 333-59052.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TIPPERARY CORPORATION

Date March 25, 2002

By /s/ DAVID L. BRADSHAW
David L. Bradshaw, President,
Chief Executive Officer and
Chairman of the Board of Directors

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ DAVID L. BRADSHAW David L. Bradshaw	President, Chief Executive Officer and Chairman of the Board of Directors	March 25, 2002
/s/ LISA S. WILSON Lisa S. Wilson	Chief Financial Officer and Principal Accounting Officer	March 25, 2002
/s/ KENNETH L. ANCELL Kenneth L. Ancell	Executive Vice President - Corporate Development and Director	March 25, 2002
/s/ EUGENE I. DAVIS Eugene I. Davis	Director	March 25, 2002
/s/ DOUGLAS KRAMER Douglas Kramer	Director	March 25, 2002
/s/ MARSHALL D. LEES Marshall D. Lees	Director	March 25, 2002
/s/ CHARLES T. MAXWELL Charles T. Maxwell	Director	March 25, 2002
/s/ D. LEROY SAMPLE D. Leroy Sample	Director	March 25, 2002

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legal counsel
Jones & Keller
Denver, Colorado

independent auditors
PricewaterhouseCoopers LLP
Denver, Colorado

transfer agent & registrar
Computershare Trust Company, Inc.
Denver, Colorado

investor relations counsel
Pfeiffer High Public Relations, Inc.
600 South Cherry Street, Suite 515
Denver, Colorado 80246
Phone: (303) 393-7044
www.pfeifferhigh.com

annual meeting
The annual meeting will be held on April 23, 2002, at the Hyatt Regency Hotel on the 3rd floor in the Parisienne Room
1750 Welton Street
Denver, Colorado
Phone: (303) 295-1234

10-KSB
Included herein.

corporate data

Information herein contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by words such as "may," "will," "expect," "anticipate," "estimate," or "continue," or comparable words. In addition, all statements other than statements of historical facts that address activities that Tipperary expects or anticipates will or may occur in the future are forward-looking statements. Readers are encouraged to read the SEC reports of Tipperary, particularly its 10-KSB for the year ended December 31, 2001, for meaningful cautionary language disclosing why actual results may vary materially from those anticipated by management.

Cautionary Note to U.S. Investors – The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this report, such as "probable" and "possible" reserves, that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in our Annual Report on 10-KSB for the year ended December 31, 2001.

tipperary
CORPORATION

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