BROWN TOM INC /DE
Form 8-K
November 13, 2002

SECURITIES AND EXCHANGE
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) November 12, 2002

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

DELAWARE	001-31308	95-1949781
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(COMMISSION FILE NUMBER)	(I.R.S. EMPLOYER IDENTIFICATION NO.)

555 SEVENTEENTH STREET, SUITE 1850 DENVER, COLORADO	80202
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	(ZIP CODE)

(303) 260-5000

(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

NOT APPLICABLE

(FORMER NAME, FORMER ADDRESS AND FORMER FISCAL YEAR,
IF CHANGED SINCE LAST REPORT)

ITEM 5. OTHER EVENTS

Tom Brown, Inc. press release dated November 12, 2002, entitled "TOM BROWN, INC. REPORTS THIRD QUARTER 2002 FINANCIAL AND OPERATING RESULTS"

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Date: November 13, 2002 Tom Brown, Inc.

By: /s/ Daniel G. Blanchard

Daniel G. Blanchard
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

By: /s/ Richard L. Satre

Richard L.Satre
Controller
(Principal Accounting Officer)

ITEM 5. OTHER EVENTS

The Company issued the following press release:

TOM BROWN, INC.
REPORTS THIRD QUARTER 2002 FINANCIAL AND OPERATING RESULTS

DENVER, NOVEMBER 12, 2002 - TOM BROWN, INC. (NYSE: TBI) today reported results from operations for the third quarter ended September 30, 2002.

For the three months ended September 30, 2002, the Company reported a net loss of $1.8 million or $0.05 per share (all per share amounts are on a diluted basis) as compared to net income of $5.8 million or $0.14 per share during the same period of the prior year. The decrease in current quarter earnings is a result of a 33% decrease in realized gas price and the previously announced $6.2 million pre-tax charge ($4.1 million after tax) to establish an allowance for a delinquent receivable from the Company's previous purchaser of its natural gas liquids in the Paradox Basin of Colorado and Utah. Excluding the cumulative effect of changes in accounting principles, the Company reported net income for the nine months ended September 30, 2002, of $2.6 million or $0.06 per share as compared to net income of $67.4 million or $1.68 per share in the corresponding period of 2001.

Discretionary cash flow for the third quarter of 2002 totaled $23.0 million, or $0.59 per share, a decrease of 54% from the $50.1 million, or $1.25 per share, in the corresponding period of 2001. For the nine months ended September 30, 2002 discretionary cash flow from operations totaled $86.3 million or $2.13 per share as compared to $186.2 million, or $4.62 per share in the same period in 2001.

"Tom Brown is performing strongly in the middle of a very challenging price environment for Rocky Mountain natural gas. We grew our production volumes 16% year over year through the third quarter by efficient execution of our drilling programs. We have reduced our lease operating expense by 14% per unit volume and have added to our exploration portfolio in all our core areas ," said Jim Lightner, Tom Brown Inc.'s Chairman, CEO and President.

"In response to extremely low Rockies gas prices we curtailed production of up to 20 Mmcfpd in September and October and significantly cut back on our development drilling programs throughout the Company due to lower cash flows and internal capital efficiency targets. Our production growth of 10%-12% this year is front-end loaded and demonstrates the quality and depth of our drilling portfolio as long as gas prices justify pursuing growth through the drill bit. We are convinced that a higher natural gas price plateau will be realized in the near future and are confident that our people, large acreage position and extensive drilling portfolio have positioned TBI very well for the future."

The following table summarizes the Company's production and commodity price realizations for the 2002 and 2001 periods ended September 30:

	THREE MONTHS ENDED			NINE MONTHS END	
PRODUCTION	9/30/02	9/30/01	CHANGE	9/30/02	9/30/01
Natural gas (Bcf)	17.9	15.8	13%	54.5	46.1
Oil (MBbls)	187	211	(11)%	642	657
NGLs (MBbls)	356	342	4%	1,081	947
Equivalent (Bcfe)	21.1	19.2	10%	64.9	55.8
REALIZED PRICES					
Natural gas ($/Mcf)	1.77	2.64	(33)%	2.01	4.30
Oil ($/Bbl)	26.05	24.30	4%	22.85	25.47
NGLs ($/Bbl)	11.80	12.27	(4)%	10.44	15.43

The Company's production in the third quarter of 2002 averaged 229.8 million cubic feet equivalent per day (Mmcfepd), a 10% increase over the same quarter in 2001. Daily production decreased sequentially from the second to the third quarter of 2002 by 15.1 MMcfepd. The sequential decrease in production is a result of the Company's curtailment of natural gas production in the Rockies and also from decreased development drilling activity because of low realized natural gas prices in the region. Gas and oil sales for the three months ended September 30, 2002 totaled $40.7 million, a decrease of $10.4 million or 20% less than the prior year's comparable period. The decrease in gas and oil sales is a result of lower realized commodity prices partially offset by higher production.

Operating expense for the current quarter and the comparable prior year's quarter averaged $0.38 per Mcfe and $0.44 per Mcfe, respectively, while production taxes of $0.14 per Mcfe were $0.05 per Mcfe higher than in the corresponding period of the prior year. The increase in production taxes per unit volume in the third quarter 2002 relative to the 2001 third quarter is a result of a cash refund of prior years' taxes credited to the third quarter 2001. Combined cash costs (operating, production taxes, interest expense and general and administrative--excluding non-cash costs) totaled $0.79 per Mcfe in the third quarter of 2002, $0.08 per Mcfe lower than in the prior year's comparable period. Net cash margin totaled $1.14 per Mcfe in the most recently completed quarter as compared to $1.80 per Mcfe in the prior year's comparable period.

Tom Brown has natural gas hedges in the form of costless collars and swaps in place at various pipeline delivery points. The costless collars and swaps are summarized below:

	NATURAL GAS COLLARS		NATURAL GAS SWAP	
PERIOD	VOLUME IN MMBTU/D	WEIGHTED AVERAGE FLOOR/CEILING	VOLUME IN MMBTU/D	WEIGHTED SWAP PR
Fourth quarter 2002	18,000	$2.98/$4.32	89,000	$2.
2003	15,000	$3.13/$4.57	53,000	$3.

The Company's marketing, gathering and processing margins totaled $5.7 million in the most recently completed quarter compared to $4.1 million in the previous corresponding period. Marketing margin for the third quarter of 2002 totaled $2.6 million as compared to $0.6 million in the prior year's third quarter. The gathering and processing margin was $3.1 million for the third quarter of this year as compared to $3.4 million for the previous year's third quarter.

The Company also entered into certain financial instruments to lock in a margin on 15,000 Mmbtu/d of gas moved under its firm transportation to the Mid Continent region during the June to October 2002 contract periods. The net margin, which the Company locked in, is approximately $0.29/Mmbtu through the contract period. However, the financial instruments are considered trading derivatives under SFAS No. 133. Therefore, the cash paid for derivatives of $1.4 million for the nine months ended September 30, 2002 is offset by the benefit from the price differential on the 15,000 Mmbtu/d transported on the firm transportation. The benefit from the price differential on the 15,000 Mmbtu/d transported on the firm transportation of $1.9 million is included in marketing and trading which, net of the cash settlement payment on the financial instruments, results in a $0.29/Mmbtu margin.

THIRD QUARTER 2002 EXPLORATION AND DEVELOPMENT PROGRAM

For the nine months ended September 30, 2002, the Company drilled or participated in a total of 62 wells in the U.S. and 11 in Canada. Of the 62 wells drilled in the U.S., at quarter end 43 wells had been completed, 13 wells were in the process of being completed and six were dry holes. At quarter-end, four wells were drilling in the U.S. Of the 11 wells drilled in Canada, at quarter end six wells had been completed, four were in the process of being completed and one was abandoned.

WIND RIVER BASIN

In the nine months ended September 30, 2002, the Company drilled 16 wells and at quarter end, 15 were completed and one was in the process of being completed. The majority of the drilling activity was in the Pavillion field where 12 successful wells were drilled. The remainder of the drilling was in the Muddy Ridge field where Tom Brown drilled four wells. The Company produced an average of 60.6 Mmcfepd net for the nine months ended September 30, 2002 from the Wind River Basin, an increase of 27% over the comparable period of the prior year.

PICEANCE BASIN

The Company drilled 18 wells in the Piceance Basin during the first three quarters of 2002. At quarter end 12 of the wells had been completed, five were in the process of being completed and one well was abandoned. The majority of the drilling occurred in the Company's White River Dome field (TBI 100% working interest) where 14 of the wells were drilled. At quarter end 12 wells had been completed, one was being completed, and one well was abandoned. The Company produced an average of 33.4 Mmcfepd net for the nine months ended September 30, 2002 from the Piceance Basin, an increase of 56% over the comparable period of the prior year.

PARADOX BASIN

In the first nine months of 2002, the Company drilled four wells with a 75% success rate in the Paradox Basin at the Company's Andy's Mesa field. The Company produced an average of 45.8 Mmcfepd net for the nine months ended September 30, 2002 from the Paradox Basin, an increase of 17% over the comparable period of the prior year.

SOUTHERN REGION (TEXAS AND LOUISIANA)

In the first nine months of the 2002, the Company drilled or participated in 19 wells in Texas and was drilling two wells at quarter-end. The Company produced an average of 49.8 Mmcfepd net for the nine months ended September 30, 2002 from the Southern Region, an increase of 15% over the comparable period of the prior year.

In the Marathon-operated Mimms Creek field (TBI 55% working interest), the Company participated in eight successful Bossier sand wells out of nine in the first three quarters of 2002. The wells completed in 2002 have had an average initial gross production rate of 3.7 Mmcfepd. As a result of its successful 2002 drilling program, the Company's average net daily production for the third quarter of 2002 from the Mimms Creek field has grown to 12 Mmcfepd, an increase of 65% from the comparable period of 2001.

In the Deep Valley project area in the Permian Basin, the Company has reached total measured depth of 20,115 feet (with a 3,215 foot lateral in the Devonian formation) at the Beefmaster #1H (TBI 50% working interest). The Company is planning to fracture stimulate the lateral. The Company continues to evaluate the Moore-Gilmore #1H (TBI 100% working interest), and expects to fracture stimulate the heel portion of horizontal lateral in the Devonian section.

CANADA

In the first nine months of 2002, the Company drilled 11 wells in Canada primarily in the Carrot Creek and Edson fields. In Canada, the Company produced an average of 24.4 Mmcfepd net for the nine months ended September 30, 2002, an increase of 2% over the comparable period of the prior year.

OUTLOOK FOR 2002

The following statements provide a summary of certain estimates based on current expectations for the fourth quarter and full-year of 2002 (the Company will also include this forward looking guidance in a Form 8-K filing). Tom Brown's exploration and production capital expenditures (excluding acquisitions) for the first three quarters of 2002 totaled $114.2 million. For the full-year 2002, the Company is projecting its exploration and development capital expenditures at approximately $145 million which is at the lower end of its prior guidance of $145-$155 million. The capital expenditures break down as follows: approximately 69% for development activities, 8% for land acquisitions and 23% for exploration.

Based upon this anticipated level of spending, Tom Brown expects 2002 production to increase approximately 10%-12% from 2001. The following table summarizes the mid-point values of the estimated production levels for the fourth quarter and full-year 2002.

	ESTIMATED FOURTH QUARTER 2002			ESTIMATED FULL YEA	
	U.S.	CANADA	TOTAL	U.S.	CANADA
Natural gas (Mcfpd)	172,000	15,500	187,500	179,000	17,300
Natural gas liquids (Bonglpd)	3,100	550	3,650	3,350	530
Oil (Bopd)	1,300	450	1,750	1,650	550
Total equivalent (Mcfepd)	198,400	21,500	219,900	209,000	23,780
Total production (Mmcfe)	18,250	1,980	20,230	76,300	8,700

The Company's marketing group earns a margin from the purchase and resale of natural gas. In addition, the Company owns and operates certain mid-stream gathering and processing assets. The Company expects the marketing, gathering and processing margin to average $3.0-$3.5 million for the fourth quarter of 2002.

Preliminary estimates for exploration expense are $8-$10 million for the fourth quarter of 2002 and $23-$25 million for the entire year, including estimated dry hole expense. Actual dry hole expense could differ based on timing and results of wells. Other operating expenses for the fourth quarter of 2002 are expected to fall within the ranges summarized below:

OPERATING COSTS ($)/Mcfe:	
Lease operating expense	0.37 - 0.39
General and administrative expense	0.21 - 0.23
Interest expense and other	0.10 - 0.11
Depreciation, depletion and amortization	1.05 - 1.07
Production taxes (% of oil and gas revenues)	8.0% - 9.0%

Provision for income taxes is expected to be approximately 35% of pre-tax earnings. Less than one-quarter of the total tax provision is projected to represent taxes currently payable.

The Company's management will hold a conference call tomorrow, Wednesday, November 13, 2002 at 12:00 p.m. Mountain Standard Time to review the third quarter 2002 results. The dial-in number to participate in the call is 800-399-0117 (U.S.) or 706-679-3393 (International), or the call can be accessed live in a listen-only mode by following the link from the Company's website www.tombrown.com.

TOM BROWN, INC. IS A DENVER, COLORADO BASED INDEPENDENT ENERGY COMPANY ENGAGED IN THE EXPLORATION FOR, AND THE ACQUISITION, DEVELOPMENT, PRODUCTION AND MARKETING OF, NATURAL GAS, NATURAL GAS LIQUIDS AND CRUDE OIL IN NORTH AMERICA. THE COMPANY'S COMMON STOCK IS TRADED ON THE NEW YORK STOCK EXCHANGE UNDER THE SYMBOL TBI.

This news release includes forward-looking statements within the meaning of section 27A of the Securities Act of 1933 and Section 21E of the Securities

Exchange Act of 1934. These statements are based on certain assumptions and analyses made by the Company in light of its experience, on general economic and business conditions and expected future developments, many of which are beyond the control of the Company. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and gas, environmental risks, operating risks, risks related to exploration and development, the ability of the Company to meet its stated business goals and other risk factors as described in the Company's 2001 Annual Report and Form 10-K as filed with the Securities and Exchange Commission. As a result of those factors, the Company's actual results may differ materially from those indicated in or implied by such forward-looking statements.

Contact: Tom Brown, Inc.
Mark Burford
Director of Investor Relations
(303) 260-5146

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TOM BROWN, INC. AND SUBSIDIARIES
Consolidated Summary Statement of Operations (Unaudited)
Three and Nine Months ended September 30, 2002 and 2001

	Three months ended September 30,		Nine months e September 3
	2002	2001	2002
	(In thousands except per share amounts)		
Revenues:			
Gas, oil and natural gas liquids sales	$ 40,749	$ 51,192	$ 135,679
Gathering and processing	4,459	4,480	14,448
Marketing and trading, net	2,643	638	3,335
Drilling	5,036	4,111	9,617
Gain on sale of property	--	--	4,004
Change in derivative fair value	299	(1,950)	(1,042)
Cash (paid) received on derivatives	(1,126)	1,032	(1,438)
Loss on marketable security	--	--	(600)
Interest income and other	105	(251)	431
Total revenues	$ 52,165	$ 59,252	$ 164,434
Costs and expenses:			
Gas and oil production	$ 7,999	$ 8,462	$ 24,318
Taxes on gas and oil production	3,029	1,661	11,829
Gathering and processing costs	1,356	1,037	4,580
Drilling operations	4,354	2,984	9,293
Exploration costs	4,150	10,490	15,334
Impairments of leasehold costs	1,392	1,200	4,173
General and administrative	3,812	4,671	13,177
Depreciation, depletion and amortization	22,823	17,973	68,846
Bad debts	6,262	42	6,478
Interest expense and other	1,832	1,936	5,737
Total costs and expenses	$ 57,009	$ 50,456	$ 163,765

(Loss) income before income taxes and cumulative effect of change in accounting principles	$ (4,844)	$ 8,796	$ 669
Income tax (provision) benefit:			
Current	(257)	9,649	(344)
Deferred	3,270	(12,675)	2,228
(Loss) income before cumulative effect of change in accounting principles	(1,831)	5,770	2,553
Cumulative effect of change in accounting principles	--	--	(18,103)
Net (loss) income	$ (1,831)	$ 5,770	$ (15,550)
Weighted average number of common shares outstanding:			
Basic	39,245	39,058	39,194
Diluted	39,245	40,079	40,449
Net income per common share before cumulative effect of change in accounting principles			
Basic	$ (0.05)	$ 0.15	$ 0.06
Diluted	$ (0.05)	$ 0.14	$ 0.06
Net (loss) income per common share			
Basic	$ (0.05)	$ 0.15	$ (0.40)
Diluted	$ (0.05)	$ 0.14	$ (0.38)

TOM BROWN, INC. AND SUBSIDIARIES
Supplemental Financial Information
Three and Nine Months ended September 30, 2002 and 2001

	Three Months Ended September 30,		Nine Se
	2002	2001	2002
		(in thousands)	
Discretionary Cash Flow (1):			
Net (loss) income	$ (1,831)	$ 5,770	$ (15,5
RECONCILING ITEMS:			
Depreciation, depletion and amortization	22,823	17,973	68,8
Exploration costs	4,150	10,490	15,3
Impairments of leasehold costs	1,392	1,200	4,1
Deferred taxes	(3,270)	12,675	(2,2
Gain on sale of property	--	--	(4,0
Current tax impact on gain on sale of property	--	--	
Change in derivative fair value	(299)	1,950	1,0
Loss on marketable security	--	--	6
Acceleration of stock options	--	--	

Cumulative effect of change in accounting principles	--	--	18,1
Discretionary cash flow	$ 22,965	$ 50,058	$ 86,3
Discretionary cash flow per common share			
Basic	$ 0.59	$ 1.28	$ 2.
Diluted	$ 0.59	$ 1.25	$ 2.

(1) Discretionary cash flow is presented herein because of its wide acceptance as a financial indicator of a company's ability to internally fund exploration and development activities and to service or incur debt. Discretionary cash flow should not be considered as an alternative to net cash provided by operating activities, net income (loss) or income (loss) from continuing operations, as defined by generally accepted accounting principles. Discretionary cash flow should also not be considered as an indicator of the Company's financial performance, as an alternative to cash flow, as a measure of liquidity or as being comparable to other similarly titled measures of other companies.

BALANCE SHEET DATA:	September 30, 2002	December 31, 2001
Total assets	$853,978	$844,975
Net working capital	7,382	11,278
Total debt	153,954	120,570
Stockholders' equity	557,922	575,228
Net debt/total book capital	21%	16%

TOM BROWN, INC. AND SUBSIDIARIES
Supplemental Operational Data (Unaudited)
Three and Nine Months ended September 30, 2002 and 2001

	Three months ended September 30,		Nine Sep
	2002	2001	2002
Production (net of royalties)			
Natural Gas (Bcf)			
United States	16.4	14.1	49.
Canada	1.5	1.7	4.
	17.9	15.8	54.
Oil (MBbls)			
United States	130.7	174.0	482.
Canada	56.3	36.6	159.
	187.0	210.6	642.

NGLs (MBbls)			
United States	303.0	301.7	936.
Canada	52.7	39.9	144.
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	355.7	341.6	1,081.
Average daily production (net of royalties)			
Natural Gas (Mmcf)			
United States	177.6	153.8	181.
Canada	16.8	18.4	17.
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	194.4	172.2	199.
Oil (Bbls)			
United States	1,420	1,892	1,76
Canada	612	397	58
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	2,032	2,289	2,35
NGLs (Bbls)			
United States	3,294	3,280	3,43
Canada	573	434	53
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	3,867	3,714	3,96
Average realized price (including effects of hedges):			
Natural Gas ($/Mcf)			
United States	$ 1.70	$ 2.63	$ 1.9
Canada	2.46	2.76	2.6
Combined	1.77	2.64	2.0
Oil ($/Bbl)			
United States	$ 26.12	$ 24.40	$ 22.5
Canada	25.90	23.89	23.5
Combined	26.05	24.30	22.8
NGLs ($/Bbl)			
United States	$ 10.73	$ 10.91	$ 9.7
Canada	17.97	22.55	14.9
Combined	11.80	12.27	10.4