BROWN TOM INC /DE
Form 8-K
November 06, 2003

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 6, 2003**

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 12. RESULTS OF OPERATIONS AND FINANCIAL CONDITION.

Tom Brown, Inc. press release dated November 6,2003, entitled

TOM BROWN, INC. REPORTS THIRD QUARTER 2003 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 6, 2003 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 12. RESULTS OF OPERATIONS AND FINANCIAL CONDITION.

The Company issued the following press release:

TOM BROWN, INC.

**REPORTS THIRD QUARTER 2003 FINANCIAL AND OPERATING RESULTS;
EQUIVALENT PRODUCTION INCREASES 29% AND NATURAL GAS PRICE
REALIZATION IMPROVES BY 132% OVER THIRD QUARTER 2002**

DENVER, November 6, 2003 Tom Brown, Inc. (NYSE:TBI) today reported results from operations for the quarter ended September 30, 2003. The Company reported net income for the three months ended September 30, 2003 of $16.0 million or $0.39 per share (all per share amounts are on a diluted basis) compared to a net loss of $1.8 million or $0.05 per share in the third quarter of 2002. The Company reported net income before the cumulative effect of changes in accounting principles for the nine months ended September 30, 2003 of $58.2 million or $1.43 per share compared to $2.6 million or $0.06 per share for the comparable period of 2002.

Tom Brown, Inc. s Chairman, CEO and President, Jim Lightner, noted that, During the third quarter of last year our production was falling due to our self-imposed drilling curtailment caused by sub-$2.00 per Mcf natural gas prices in the Rockies. This year, with higher natural gas prices, our recently-closed Matador acquisition and successful drilling programs, our production is up 29% from last year s third quarter. The strength of our exploration and development drilling programs has us heading into 2004 with strong production, cash flow and profitability momentum. Our inventory of over 2,000 drilling locations coupled with a strong exploration portfolio should enable us to continue this trend well out into the future.

Included in the third quarter results are one-time, pre-tax charges of $4.0 million ($2.5 million after tax) in interest expense associated with the termination of the Canadian term loan and bridge bank facilities. These facilities were terminated in conjunction with the debt and equity offerings the Company completed in September 2003. Additionally, the Company recorded a pre-tax charge of $1.6 million ($1.0 million after tax) in the third quarter associated with certain non-compete agreements related to the Matador acquisition.

Discretionary cash flow for the third quarter of 2003 totaled $70.9 million (see reconciliation below to net cash provided by operating activities of $74.3 million), an increase of 208% from $23.0 million in the corresponding period of 2002. Discretionary cash flow for the nine months ended September 30, 2003 totaled $193.2 million (see reconciliation below to net cash provided by operating activities of $159.7 million) compared to $86.3 million for the comparable period of the prior year. The majority of the increase in earnings and discretionary cash flow is attributable to higher production and natural gas and oil prices.

The following table summarizes the Company s production and commodity price realizations for the 2003 and 2002 periods ended September 30:

	Three Months Ended	Nine Months Ended

9/30/03	9/30/02	Change	9/30/03	9/30/02	Change

Production

Natural gas (Bcf)	23.1	17.9	29%	56.9	54.5	4%
Oil (MBbls)	332	187	78%	721	642	12%
NGLs (MBbls)	356	356	0%	1,102	1,081	2%
Equivalent (Bcfe)	27.3	21.1	29%	67.8	64.9	4%

Realized Prices *

Natural gas ($/Mcf)	4.10	1.77	132%	4.02	2.01	100%
Oil ($/Bbl)	29.27	26.05	12%	29.02	22.85	27%
NGLs ($/Bbl)	17.87	11.80	51%	18.17	10.44	74%

*Includes effects of hedging.

Third quarter 2003 production averaged 296.2 million cubic feet equivalent per day (Mmcfepd), a 29% increase over the comparable period of 2002. Gas, oil and natural gas liquids sales for the three months ended September 30, 2003 totaled $110.9 million, an increase of $70.2 million, or 172%, from the prior year s comparable period due to higher production and commodity prices in the current quarter.

Production expense for the most recently completed quarter and the comparable prior year s quarter averaged $0.49 per Mcfe and $0.38 per Mcfe, respectively, while production taxes of $0.35 per Mcfe in the most recently completed quarter were $0.21 per Mcfe higher than in the corresponding period of the prior year. Production expenses were approximately $1.0 million, or $0.04 per Mcfe, higher than expected for the third quarter of 2003 primarily due to workover and plant turnaround expenses. The increase in production taxes is a result of higher commodity prices. Combined cash costs comprised of production expense, production taxes, interest expense (excluding one-time charges incurred relative to the termination of the bridge facility and term loan) and general and administrative expense totaled $1.36 per Mcfe in the third quarter of 2003, $0.59 per Mcfe higher than in the prior year s comparable period. Net cash margin (gas and oil sales less combined cash costs) totaled $2.71 per Mcfe in the most recently completed quarter compared to $1.16 per Mcfe in the prior year s comparable period.

Tom Brown has fixed price physical sales and natural gas hedges in the form of costless collars and swaps in place at various pipeline delivery points (i.e., includes location differentials) that are summarized below:

	Natural Gas Collars		Natural Gas Swaps/Physical Sales	
Location/Period	**Volume in Mmbtu/d**	**Weighted Average Floor/Ceiling ($/Mmbtu)**	**Volume in Mmbtu/d**	**Weighted Average Swap Price ($/Mmbtu)**
Fourth Quarter 2003:				
Rockies (Colorado/Wyoming)	43,200	$ 3.73/6.25	14,300	$ 2.96
Canada	1,685	$ 3.23/4.45	2,527	3.13
Southern Region (Texas)	43,400	$ 4.50/8.80	2,527	3.45
Total Fourth Quarter 2003	88,285	$ 4.10/7.47	19,354	3.05
Full-year 2004:				
Rockies (Colorado/Wyoming)	11,200	$ 4.19/7.12		
Southern Region (Texas)	28,300	$ 4.28/7.44		
Total 2004	39,500	$ 4.25/7.35		

The 2004 Rockies hedges are an average of the full-year 2004, which is comprised of 45,000 Mmbtu/d for the first quarter of 2004 with no other volumes fully hedged thereafter. However, the Company has entered into basis hedges for an additional 17,000 Mmbtu/d from April-October of 2004 for Rockies production delivered into Northwest Pipeline at a differential of $0.67 per Mmbtu.

The Company s marketing, trading, gathering and processing margins (revenues less combined costs) totaled $2.3 million in the most recently completed quarter compared to $5.7 million in the corresponding period in the prior year. The marketing and trading margin for the third quarter of 2003 was a loss of $0.6 million compared to gain of $2.6 million in the prior year s third quarter. The marketing and trading margin is lower primarily because the spread between Rockies and Mid-Continent basis differentials was tighter this year resulting in a reduced margin on the firm transportation held by the Company. The gathering and processing margin was $2.9 million for the third quarter of this year compared to $3.1 million for the previous year s third quarter primarily due to reduced gathering volumes.

2003 Exploration and Development Program

For the nine months ended September 30, 2003, the Company drilled or participated in a total of 129 wells in the U.S. and 12 in Canada. Of the 129 wells drilled in the U.S., as of September 30, 2003, 94 wells had been completed, 24 wells were in the process of being completed and 11 were abandoned. Of the 12 wells drilled in Canada, at September 30, 2003

For the nine months ended September 30, 2003, the Company drilled or participated in a total of 129 wells in the U.

five wells had been completed and seven wells were in the process of being completed. As of September 30, 2003, Tom Brown had 16 wells drilling in the U.S. and two in Canada.

Wind River Basin

For the nine months ended September 30, 2003, the Company drilled 11 gross wells, ten of which are successful and one that is currently being tested. Eight of the successful wells were in the Frenchie Draw field. Two of the 11 wells drilled were exploratory wells; Blazing Saddles 33-32 (TBI 80% working interest) and Curly 10-22 (TBI 25% working interest). Blazing Saddles 33-32 was drilled to 8,300 feet to evaluate various Fort Union intervals and has been connected to a sales line and is currently producing at 2.7 Mmcfepd. With the successful results from this wildcat the Company is moving in a rig to drill a step-out well, the Lili 33-24 (TBI 74.29% working interest). Success in the Lili 33-24 could create a significant development area for the Company. In the Company s Fuller area, which is south of the Blazing Saddles and Lili wells, the Company is preparing for an active development drilling program targeting the Fort Union formation. The Company continues to test the Curly 10-22, a Lance formation exploratory well. The Company is also participating with other industry partners in a 180 square mile 3-D seismic program along the southern flank of the Wind River Basin in Fremont County.

The Company produced an average of 51.7 Mmcfepd net for the nine months ended September 30, 2003 from the Wind River Basin compared to 60.6 Mmcfepd net in the comparable period of the prior year. This production decline was due to reduced drilling activity in the Basin. There has been no drilling activity on the Wind River Indian Reservation since mid-year 2002 due to finalization of certain contractual issues with the Northern Arapahoe and Eastern Shoshone Indian tribes.

Greater Green River Basin

In the first nine months of 2003, the Company drilled 13 successful out of 16 gross wells in the Greater Green River Basin. The Company has drilled and is currently completing the Gamblers Reservoir 14-33 (TBI 50% working interest), which is an offset well to the previously announced exploratory success, Gamblers Reservoir 43-32 (TBI 50% working interest). The Company produced an average of 23.8 Mmcfepd net for the nine months ended September 30, 2003, from the Greater Green River Basin compared to 22.3 Mmcfepd net in the comparable period of the prior year. The Company has also commenced drilling the West Slope 33-32 (TBI 50% working interest), a 13,000 foot Lewis exploratory well.

Piceance Basin

The Company drilled 27 gross wells, all of which were successful, in the first nine months of 2003 in the Piceance Basin. This drilling occurred in the second and third quarters principally in the White River Dome field and Parachute areas. The Company has drilled eight successful wells (TBI 75% working interest) to the Williams Fork formation in the Parachute/South Parachute area. Four of the wells are flowing to sales at an average initial production rate of 1.7 Mmcfepd. This success has created a significant inventory in the South Parachute area of future drilling locations which are being prepared for the 2004 drilling program.

The Company produced an average of 29.5 Mmcfepd net for the nine months ended September 30, 2003 from the Piceance Basin as compared to 33.4 Mmcfepd net in the comparable period of the prior year. The production decrease was a result of greatly reduced drilling activity in the fourth quarter of 2002 followed by no wells being drilled in the Piceance in the first quarter of 2003 due to winter seasonal restrictions.

Paradox Basin

The Company drilled 10 successful out of 11 gross wells in the Paradox Basin in the first nine months of 2003, primarily in the Andy s Mesa and Hamilton Creek fields. With the success of the Andy s Mesa drilling program, the Company has hit record gross production levels of approximately 30 Mmcfepd from the field. The Company is continuing to pursue a number of exploratory prospects in this area, many of which will be tested in 2004. The Company produced an average of 51.3 Mmcfepd net for the nine months ended September 30, 2003 from the Paradox Basin, as compared to 45.6 Mmcfepd net in the comparable period of the prior year.

Southern Region (Permian, East Texas Basins, South Texas)

In the first nine months of the 2003, the Company drilled or participated in 57 successful out of 64 gross wells in the Southern Region which includes drilling activity on the Matador properties beginning in the third quarter of 2003. Of the 64 wells drilled in the Southern Region 31 were in East Texas Basin and 33 were in the Permian Basin.

At the Deep Valley Horizontal Devonian project area in the Permian Basin, the Company is drilling the Horry Pitts 49-01H (TBI 50% working interest). After taking a significant gas kick while drilling the lateral, a drill stem test of the Devonian was run, which flowed at 8.6 Mmcfd with 5,350 pounds per square inch (psi) flowing tubing pressure. The Company is now back to drilling the lateral. In East Texas, in the Mimms Creek field (TBI 55% working interest) the Company participated in fourteen wells in the first nine months of 2003 and currently has two rigs running in the field. Our most recent Mimms Creek well, the Utley A-9, had an initial production rate of 6.0 Mmcfepd compared to a field-wide average rate of 3.5 Mmcfepd. The Company produced an average of 68.1 Mmcfepd net for the nine months ended September 30, 2003 from the Southern Region compared to 49.8 Mmcfepd net in the comparable period of the prior year.

Canada

In the first nine months of 2003, the Company drilled 12 gross wells, all of which were successful, in Canada primarily in the Carrot Creek and Edson fields. The Company produced an average of 24.1 Mmcfepd net for the nine months ended September 30, 2003 as compared to 24.5 Mmcfepd net in the comparable period of the prior year.

Outlook for 2003

The following statements provide a summary of certain estimates for the fourth quarter and full-year of 2003 based on current expectations. Tom Brown s exploration and development capital expenditures (excluding acquisitions) for the first nine months of 2003 totaled $163.5 million. For the full-year 2003, the Company is forecasting exploration and development capital expenditures in the range of $245-$255 million (excluding the cost to acquire Matador), which includes approximately 70%-75% for development activities and the remainder for land acquisitions and exploration.

Based upon this anticipated range of capital spending, Tom Brown s full-year 2003 production guidance is 96-98 Bcfe (85% natural gas). The mid-point estimate for the fourth quarter 2003 production is 29.2 Bcfe as summarized in the following table.

	Fourth Quarter 2003		
	U.S.	**Canada**	**Total**
Natural gas (Mcfpd)	253,600	17,000	270,600
Natural gas liquids (Bonglpd)	3,390	660	4,050
Oil (Bopd)	3,370	330	3,700
Total equivalent (Mcfepd)	294,160	22,940	317,100
Total production (Mmcfe)	27,100	2,100	29,200

Estimates for exploration expense are $13-$16 million for the fourth quarter of 2003 and $34-$37 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 remainder of 2003 are expected to fall within the ranges summarized below based on our estimated production:

OPERATING COSTS/Mcfe:

Lease operating expense	$0.45	-	$0.47
General and administrative expense	0.24	-	0.26
Interest expense and other	0.24	-	0.27
Depreciation, depletion and amortization	1.18	-	1.23
Production taxes (% of oil and gas revenues)	8.5%	-	9.5%

The Company s management will hold a conference call today, Thursday, November 6, 2003 at 1:00 p.m. Mountain Time to review the third quarter 2003 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 Investor Relations page of 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 NYSE 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, effective integration of acquired operations, the ability of the Company to meet its stated business goals and other risk factors as described in the Company s 2002 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 Income Statement (Unaudited)

Three and Nine Months ended September 30, 2003 and 2002

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	2003	2002
	(In thousands except per share amounts)			
Revenues:				
Gas, oil and natural gas liquids sales	$ 110,902	$ 40,749	$ 269,862	$ 135,679
Gathering and processing	4,133	4,459	15,001	14,448
Marketing and trading	5,186	11,007	27,834	47,039
Drilling	5,799	5,036	12,754	9,617
Gain on sale of property				4,004
Change in derivative fair value		299	1,913	(1,042)
Cash (paid) received on derivatives		(1,126)		(1,438)
Loss on marketable securities				(600)
Interest income and other	189	105	816	431
Total revenues	126,209	60,529	328,180	208,138
Costs and expenses:				
Gas and oil production	13,246	7,999	29,936	24,318
Taxes on gas and oil production	9,504	3,029	23,127	11,829
Gathering and processing costs	1,239	1,356	5,310	4,580
Trading	5,812	8,364	27,402	43,704
Drilling operations	4,937	4,354	10,968	9,293
Exploration costs	10,674	4,150	21,353	15,334
Impairments of leasehold costs	1,853	1,392	4,816	4,173
General and administrative	6,962	3,812	17,612	13,177
Depreciation, depletion and amortization	32,296	22,823	76,866	68,846
Bad debts	102	6,262	354	6,478
Accretion expense	417		1,005	
Interest expense	11,365	1,474	14,717	4558
Other	2,277	358	4,743	1,179
Total costs and expenses	100,684	65,373	238,209	207,469
Income (loss) before income taxes and cumulative effect of change in accounting principle	25,525	(4,844)	89,971	669
Income tax benefit (provision)				
Current	(98)	(257)	457	(344)
Deferred	(9,416)	3,270	(32,264)	2,228
Income before cumulative effect of change in accounting principle	16,011	(1,831)	58,164	2,553
Cumulative effect of change in accounting principle			(929)	(18,103)
Net income (loss)	$ 16,011	$ (1,831)	$ 57,235	$ (15,550)
Weighted average number of common shares outstanding:				
Basic	40,391	39,245	39,782	39,194
Diluted	41,465	39,245	40,813	40,449

Income (loss) per common share before cumulative effect of change in accounting principle								
Basic	$	0.40	$	(0.05)	$	1.46	$	0.06
Diluted	$	0.39	$	(0.05)	$	1.43	$	0.06
Net income (loss) per common shareholder								
Basic	$	0.40	$	(0.05)	$	1.44	$	(0.40)
Diluted	$	0.39	$	(0.05)	$	1.40	$	(0.38)

12

TOM BROWN, INC. AND SUBSIDIARIES

Supplemental Financial Information

Three and Nine Months ended September 30, 2003 and 2002

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	2003	2002
	(in thousands)			
Reconciliation to net cash provided by operating activities:				
Discretionary cash flow (1)	$ 70,921	$ 22,965	$ 193,242	$ 86,316
Exploration costs	(10,674)	(4,150)	(21,353)	(15,334)
Add back only dry hole cost	4,445	168	8,713	3,010
Changes in current assets and liabilities, net	9,553	2,844	(20,869)	5,316
Net cash provided by operating activities	$ 74,245	$ 21,827	$ 159,733	$ 79,308

(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, 2003	December 31, 2002
Total assets	$ 1,536,934	$ 850,952
Net working capital	12,430	(8,887)
Total debt	409,080	133,172
Shareholders equity	782,061	563,618
Net debt/total book capital	34%	20%

13

TOM BROWN, INC. AND SUBSIDIARIES

Supplemental Operational Data (Unaudited)

Three and Nine Months ended September 30, 2003 and 2002

	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
Production (net of royalties)				
Natural Gas (Bcf)				
United States	21.5	16.4	52.2	49.6
Canada	1.6	1.5	4.7	4.9
	23.1	17.9	56.9	54.5
Oil (Mbbls)				
United States	284.2	130.7	564.0	482.6
Canada	47.5	56.3	156.7	159.8
	331.7	187.0	720.7	642.4
NGLs (Mbbls)				
United States	303.2	303.0	951.8	936.3
Canada	52.4	52.7	150.6	144.7
	355.6	355.7	1,102.4	1081.0
Average daily production (net of royalties)				
Natural Gas (Mmcf)				
United States	233.9	177.6	190.8	181.9
Canada	17.4	16.8	17.4	17.8
	251.3	194.4	208.2	199.7
Oil (Bbls)				
United States	3,090	1,420	2,060	1,768
Canada	517	612	574	585
	3,607	2,032	2,634	2,353
NGLs (Bbls)				
United States	3,296	3,294	3,488	3,430
Canada	569	573	551	530
	3,865	3,867	4,039	3,960
Average realized price (including effects of hedges):				
Natural Gas ($/Mcf)				
United States	$ 4.08	$ 1.70	$ 3.96	$ 1.94
Canada	4.36	2.46	4.72	2.68
Combined	4.10	1.77	4.02	2.01
Oil ($/Bbl)				
United States	$ 29.50	$ 26.12	$ 28.77	$ 22.56
Canada	27.90	25.90	29.92	23.50
Combined	29.27	26.05	29.02	22.85
NGLs ($/Bbl)				
United States	$ 17.05	$ 10.73	$ 17.15	$ 9.74
Canada	22.60	17.97	24.59	14.98
Combined	17.87	11.80	18.17	10.44