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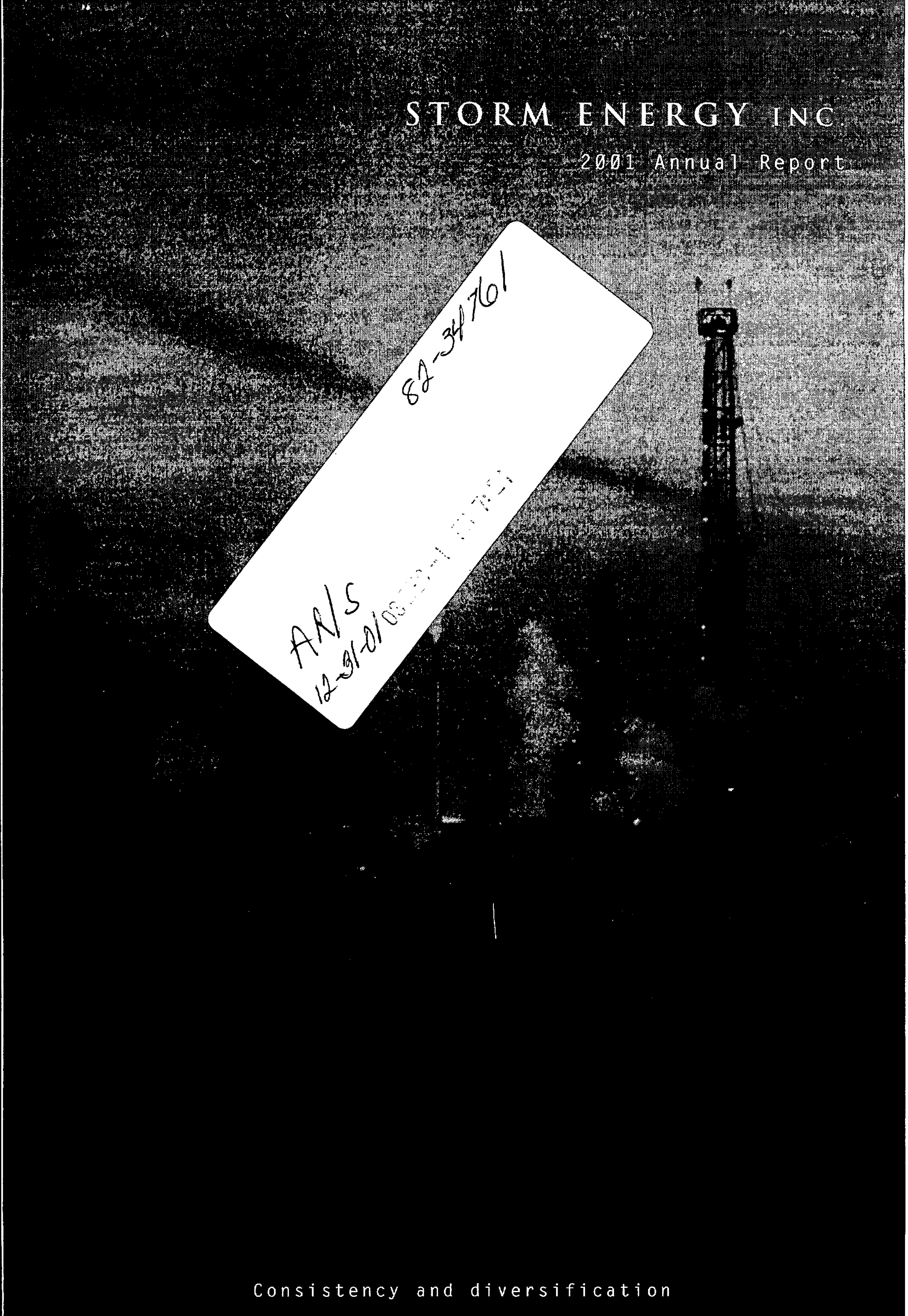
STORM ENERGY INC.

STORM ENERGY INC.

2001 Annual Report



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Consistency and diversification

Storm Energy Inc. ("Storm") is a Calgary based junior oil and gas exploration and production company, whose shares trade on The Toronto Stock Exchange under the symbol "SME". Storm has a total capitalization of approximately $415 million and current production of approximately 12,800 Boe/d (6:1). In November 1998, Storm was recapitalized and a new management team, motivated by a large direct investment in Storm common shares, negotiated the opportunity to employ its experience, proven exploration strategy and financial resources to build shareholder value in a way that is sustainable over the long term.

Three years of proven management has resulted in consistently strong results and we are pleased to report Storm's comparative annual production growth and diluted per share results as follows:

	2001	2000	1999
• Barrels of oil equivalent (Boe/d 6:1)	+ 74%	+ 123%	+ 44%
• Cash flow per share	+ 33%	+ 302%	+ 61%
• Net income per share	+ 47%	+ 381%	+ 128%
• Net asset value per share	+ 29%	+ 206%	+ 89%
• Market price per share (year end)	+ 64%	+ 147%	+ 12%

In the longer term, Storm is confident that growth in the above key per share performance measures can be sustained through volatile commodity price cycles by the consistent implementation of its proven exploration, acquisition and financial strategies as fully detailed in this report.

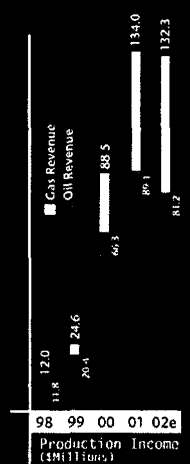
The Annual Meeting of Shareholders will be held at 2:45 pm on Wednesday, May 15, 2002, in the Wildrose Centre, Eau Claire Sheraton Suites Hotel, Calgary, Alberta. All shareholders and invited guests are encouraged to attend.

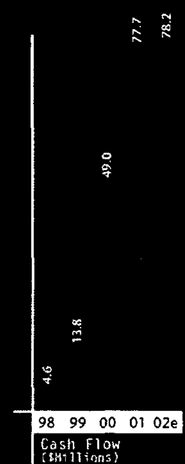
Certain information regarding Storm set forth in this document, including management's assessment of Storm's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Storm's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Storm's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Storm will derive therefrom.

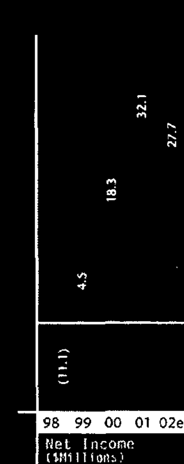
COMPARATIVE DATA

The tabular data below illustrate Storm's growth profile over the last four years and into 2002. Estimates for 2002 are based on certain assumptions, estimates and projections. See Management's Discussion and Analysis starting on page 20.

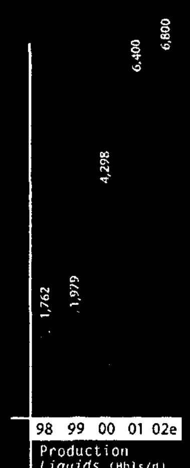
FINANCIAL

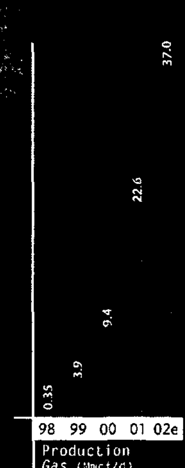


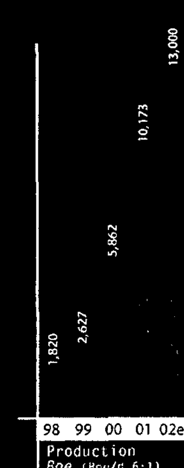




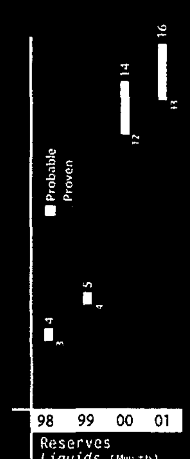
PRODUCTION

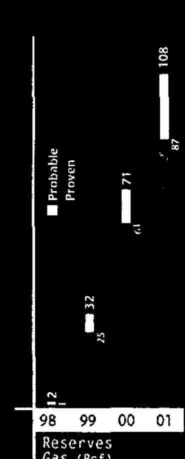






RESERVES





HIGHLIGHTS

Year ended December 31,	2001	2000	% Change
FINANCIAL ($ thousands, except where noted)			
Oil and gas revenues	134,588	94,381	43
Hedge loss	(560)	(5,852)	(90)
Cash flow from operations	77,707	48,999	59
Per share - basic ($)	2.81	2.08	35
Per share - diluted ($)	2.72	2.05	33
Net income	32,142	18,339	75
Per share - basic ($)	1.16	0.78	49
Per share - diluted ($)	1.13	0.77	47
Long term debt, including working capital	65,990	78,466	(16)
Shareholders' equity	91,055	58,389	56
Capital expenditures, net	65,751	101,352	(35)
Total assets	207,882	173,955	20
Weighted average common shares (000's)			
Basic	27,627	23,576	17
Diluted	28,559	23,869	20
Common shares outstanding (000's)			
Basic	27,782	27,470	1
Diluted	29,662	29,277	1
Return on average shareholders' equity (%)	43	40	8
OPERATIONS			
Average daily production			
Crude oil and NGL's (Bbls/d)	6,400	4,298	49
Natural gas (Mcf/d)	22,640	9,386	141
Barrels of oil equivalent (Boe/d @ 10:1)	8,664	5,236	65
Barrels of oil equivalent (Boe/d @ 6:1)	10,173	5,862	74
Average product prices			
Crude oil ($CDN/Bbl)	38.19	44.39	(14)
WTI ($US/Bbl)	25.95	30.26	(14)
Natural gas ($CDN/Mcf)	5.57	7.26	(23)
Wells drilled			
Gross	47.00	36.00	31
Net	37.60	29.82	26
Working interest (%)	80	84	
Reserves - proved and probable			
Crude oil and NGL's (Mstb)	15,809	14,061	12
Natural gas (Mmcf)	108,014	71,009	52
Oil equivalent (Mboe @ 10:1)	26,610	21,162	26
Oil equivalent (Mboe @ 6:1)	33,811	25,896	31
Undeveloped land			
Gross acres	330,384	307,562	7
Net acres	252,926	228,450	11
Working interest (%)	77	74	

SME

REPORT TO SHAREHOLDERS

We are well into this winter's drilling and recompletion program, which should ensure that we more than double BC gas volumes to 35 MMcf/d by the end of the first quarter.

Storm had a great year in 2001. We delivered results CONSISTENT with past years' performance in terms of significant volume growth and cost control. This CONSISTENCY ensured our profitability, even though our Boe (6:1) commodity prices averaged 18% less than in the previous year. Also, in delivering our 2001 performance, we successfully DIVERSIFIED the focus of our operations geographically, to include a second core project in northeastern British Columbia, and towards natural gas. The successful DIVERSIFICATION achieved in 2001 will make delivering CONSISTENT results in 2002 and beyond more achievable.

EFFICIENT AND PROFITABLE GROWTH

As a public company, Storm tries to achieve the premium market valuation that is attributable to growth companies. We believe this valuation is possible if we can consistently deliver volume growth well in excess of a normal range of commodity price volatility, and do not dilute our operational progress with new equity. In 2001, we increased our Boe production volumes (6:1) by 74% to 10,173 Boe/d. Despite commodity prices being lower than in 2000, we were able to increase our cash flow per share by 33% to $2.72 and net income per share by 47% to $1.13, on a diluted basis. Liquids production increased by 49% to 6,400 Bbls/d on the continued successful development of our Red Earth area and natural gas production volumes more than doubled to 22.6 Mmcf/d on the strength of new core projects at Cabin and Tommy Lakes. In contrast to the two previous years, acquisitions were not a meaningful part of our 2001 success. All of our growth came from the continued enhancement of existing assets and drilling success in our core areas. Capital expenditures totaled $65.7 million representing 85% of our $77.7 million cash flow. Although overall capital expenditures were down 35% from 2000 levels, our internal program was accelerated with the drilling of 47 wells, up from 36 in 2000. As important as our increasing financial performance on a per share basis, was the profitability we were able to demonstrate in a decreasing commodity price environment. Our return on average shareholders' equity was 43% versus 40% in 2000 and our return on average capital employed was 25% compared to 20% in 2000.

OPERATIONS HIGHLIGHTS

During the 2001-2002 winter season, we spent over $15 million on our new gas plays at Cabin and Tommy Lakes in northeastern British Columbia. At Cabin we tied in a successful new well and a recompleted well to two new Storm operated facilities at Kotcho and Louise. We shot two large 3D seismic surveys to better image the target Slave Point dolomitized reef edge reservoirs, which successfully identified enough locations on Storm acreage to support two years of activity. This winter's four well program has begun successfully with the first two wells being cased, completed and tied in at Kotcho. At a cost of $1.7 million per well, each capable of producing over 5 Mmcf/d and recovering 6-10 Bcf, our play exposure at Cabin provides a high impact project capable of materially increasing reserves and production with a three to four well program. Tommy Lakes, by contrast, provides us with a huge volume of low risk development reserve and production additions for a number of years. Individual wells average 600-800 Mcf/d with associated reserves of 1.5-3.0 Bcf. Of the 600 Bcf of gas in place only 111 Bcf has been recovered to date and our share of the total current production of 59 Mmcf/d is 34%. After this winter's program we will have 15 undrilled spacing units within the pool boundary and as many as 20 downspaced locations that could eventually be drilled. Winter 2000-2001 activity was focused on infrastructure modifications, which successfully offset minor declines and grew production by 20%. We are well into this winter's drilling and recompletion program, which should ensure that we more than double British Columbia gas volumes to 35 Mmcf/d by the end of the first quarter, and achieve a corporate average rate for the year of 37 Mmcf/d. Achieving these volumes will result in gas as a percentage of our Boe (6:1) production mix increasing from 26% to 48% in three years.

At Red Earth we had an extremely profitable year despite not having either a significant single discovery or a major acquisition which has driven past years' performance. Production increased by 49% to 5,886 Bbls/d, representing 58% of our average Boe (6:1) production for the year. Our 33 well program included discoveries at Evi West, Evi North, Ogston and Red Earth. Our 70% completion percentage added, on average, 160,000 Bbls/well of proved producing reserves at a $7.30/Bbl finding and development cost. Maintaining this performance as we evaluate the 50 prospects on our 89,000 acres of undeveloped land will ensure Red Earth's contribution to increasing liquid volumes for at least the next two years. We continue to access good quality opportunities to expand our operations at Red Earth as evidenced by our recent commitment to explore 35,000 acres of Loon River First Nation lands, in partnership with the band. We have a 25 square mile 3D seismic survey evaluating one-third of the block this winter and hope to drill our first test wells this summer. The Loon Lake pool saw positive reserve revisions in 2001 and although the pool continues to perform well, its impact on our overall performance has lessened as it represents less than 20% of our current production and reserves.

Red Earth was also the site of our first foray into the power generation business. We installed 2 Mw/hr of turbine generating capacity fueled by previously flared solution gas at our main 4-36 Evi oil battery. Although reduced electricity prices have lengthened the payout period of the project considerably, the combined benefit of reduced emissions and improved air quality will see us participate in at least two small power generation projects at Red Earth in 2002. We have reduced our flared volumes at Red Earth by approximately 45% with these initiatives and we would like to increase that percentage to a level equal to a minimum of 60% of our solution gas volumes over the next 12-18 months.

Our operational progress in these areas resulted in proven reserve increases of 44% to 87.1 Bcf of natural gas and 13% to 13.3 Mmbls of liquids, after accounting for our full year's production. Over 81% of our proven reserves are producing and 90% of our established reserves are proven. These percentages are high relative to other producers and consistent with past years' reserve bookings for Storm. Lower percentages of proven undeveloped or probable reserves minimize the risk of negative reserve revisions in future years. The present value of our future revenue from established reserves of 30.8 million Boe (6:1), discounted at 10%, is $311 million. This 16% increase in value is less than the 29% increase in reserve volumes because of the lower price forecast used by the independent evaluators. Average prices over the first three years of the forecast were 10% lower for crude oil and 30% lower for natural gas, when compared to the price forecasts used in the year end 2000 independent reserve evaluation.

INDUSTRY PRICING ENVIRONMENT

In 2001, commodity prices demonstrated the volatility that leads to the "boom and bust" cycles that characterize our industry. It opened as a "boom" and for some, ended the year with low equipment utilization or high debt levels more reminiscent of a "bust" cycle. Scarcity concerns for natural gas and electricity shortages in California drove first quarter gas prices to $9.04/Mcf at AECO, supporting an average Storm price of $11.04/Mcf. Supply response, strong storage injection, a slow start and a mild winter led to fourth quarter 2001 gas prices of $3.40/Mcf and an average corporate price for the year of $5.57/Mcf. As dramatic as a 69% decline in price may seem, average prices were still very close to all-time highs. WTI crude prices averaged a very respectable $US 25.95/Bbl in 2001, down 14% from the exceptional prices in 2000. As with gas, a weak Canadian dollar supported Edmonton posted light sweet crude prices of $39.18/Bbl, the second highest level in the last 15 years. Storm's light sweet crude commanded a premium price of $38.19/Bbl, reflecting a differential of $0.99/Bbl. Storm makes investment decisions with an expectation of average prices between $US 18-20 WTI, $US 2.50-$2.75 NYMEX gas prices, and an exchange rate of 65¢ ($CDN/$US). If we can hedge prices at levels higher than this to support an acquisition, as we did at Tommy Lakes, we will hedge for the time period estimated to reach payout. For our 2002 forecasts, we are using estimates of $CDN 31.87/Bbl for liquids, $CDN 3.45/Mcf for natural gas and a $CDN/$US exchange rate of 65¢.

CONSISTENT STRONG RESULTS THROUGH OUR EFFICIENT COST STRUCTURE

One important theme from our 2001 performance was the consistency with past years' strong results in management of the costs we incur to find, develop and produce our reserves and the overhead it takes to manage our business. The energy business is a commodity business where no single participant, outside of OPEC, has any meaningful influence on price. By focusing on the aspects of our business that are within our control, namely on premium priced products and the cost structure we can consistently deliver, we can maintain a high level of profitability in all but the lowest points in the commodity price cycle. Our operating expenses decreased by 7% to $4.24/Bbl for crude oil and by 2% to 55¢/Mcf for natural gas. We do not anticipate any significant improvements in this performance, given the high water cuts associated with our crude oil production and the sour gas processing costs of our British Columbia gas, but expect that they will be stable in this range for 2002. General and administrative expenses decreased 17% to 73¢/Boe (6:1) and should average 60¢/Boe in 2002. In determining our finding and on stream costs for 2001, we are using the methodology proposed by Canadian Securities Administrators National Instrument No. 51-101, which will be mandatory for reporting issuers next year. The changes under this policy are the use of a 6:1 conversion of natural gas to equivalent barrels of crude oil and the inclusion of changes in the additional capital required to bring on booked volumes of proven undeveloped or probable additional reserves. Our results for 2000 and 1999 have been restated in accordance with the policy for comparative purposes. Finding and on stream costs in 2001 were $6.67/Boe, down 7% from last year. We are pleased with this performance given more gas additions and no acquisitions. Based on our accumulated assets, expertise, and opportunities in each of our core areas, we believe that the top quartile performance in managing costs that we have demonstrated in previous years and repeated in 2001, is deliverable again in 2002.

Field netbacks for Storm's production averaged $22.55/Boe (6:1) in 2001, down 10% from 2000 due to a 18% drop in realized sales price. Netbacks reflect the available capital to reinvest after recovering costs reported on a per barrel basis. The recycle ratio reflects the effectiveness of reinvesting the netback from each barrel by dividing the netback by the cost to find and develop each barrel. This provides a measure of our ability to grow through the reinvestment of our own resources. Storm's recycle ratio for proven reserves in 2001 was a very profitable 3.4 times, similar to last year's performance. A recycle ratio above 2.0 times signals a profitable reinvestment climate.

When looking back on 2001 from an industry wide perspective, we have tried to draw some conclusions that will frame our strategy for 2002. There are a smaller number of peers in the mid-cap ($CDN 200 million – $1.0 billion) range and several in this range have highly leveraged balance sheets. Many of last year's successful acquirers will need to pare debt but will have a difficult time achieving the $/Boe metrics that they paid. Royalty trusts, well-financed startups and remaining competitors will ensure adequate competition for most assets, but deals of size, and those with shorter reserve life indexes should be more reasonably priced than in 2001. Capital markets seem to be focusing on recapitalizations and the acquisition market opportunities. Correspondingly, land sale prices and equipment utilization rates are dropping as the number of companies dwindle and budgets are trimmed from previous year's levels. We intend to invest aggressively on our internal opportunities in our existing core areas during the first quarter of 2002 to drive production gains to a projected level of 13,500-14,000 Boe/d (6:1) and confirm the prospectivity of our inventory, particularly in the newer areas of Cabin and Tommy Lakes. After breakup, activity will shift to Red Earth, Sylvan Lake, Fort St. John and to a lesser degree Pouce Coupe. We expect to end the first quarter with debt at approximately 1.0 times our forecast 2002 cash flow. Our current budget has us spending less than cash flow over the last three quarters with debt decreasing to one half our forecast cash flow by year-end. We believe opportunities to expand our exploration activities in our existing core and selected new areas will be better than in 2001 due to a lack of competition and a greater focus on acquisitions. We will try to maximize on these opportunities. We will be financially positioned to consider increased exploratory exposures or selected property acquisitions up to $100 million and with that level of flexibility we do not foresee the likelihood of requiring additional equity capital.

Our forecasts for 2002 are based on initial commodity price estimates of $US 22.00/Bbl WTI for crude oil and $3.45/Mcf for natural gas. We plan to spend $40 million and realize average production of 6,800 Bbls/d of liquids and 37 Mmcf/d of gas, or roughly 13,000 Boe/d (6:1). Cash flow should reach $78 million, earnings should approximate $28 million, and year-end debt should be less than $30 million. As mentioned, we have the ability to increase our activity as opportunities dictate and we will adjust our projections as funds are committed or better information becomes available.

Storm has been active in its current form for just over three years. During that time, our production and reserves have grown six fold and our cash flow per share is almost nine times higher. The dominant factor in our achievements to date has clearly been the skill and determination of our employees, almost all of whom are shareholders. Thanks for your dedication. Shareholders should take comfort that the same proven skill-set that has served them to this point will be delivering the future growth of Storm.

I would also like to take the opportunity to thank our independent directors, Messrs. Brussa, Farries, MacDonald and Turnbull for their contributions to our direction and for their guidance.

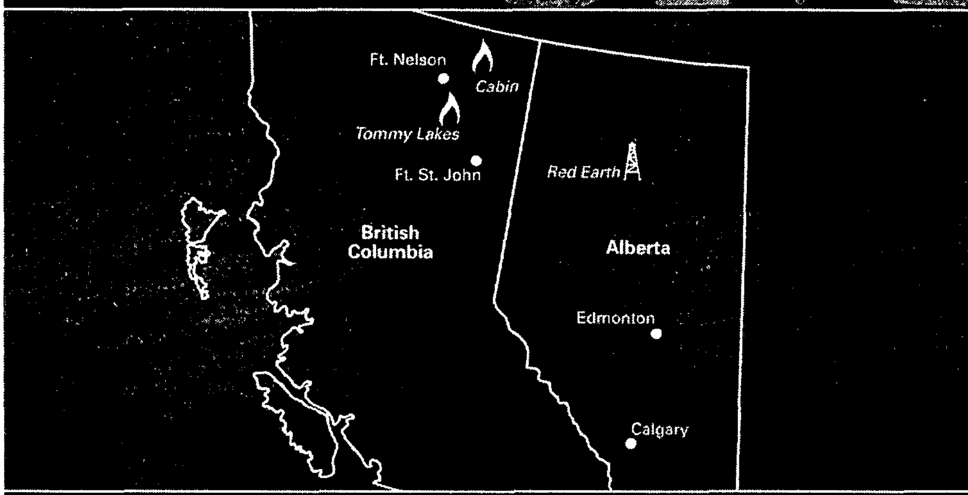
Operational results to date in 2002 are extremely encouraging. We have had initial drilling success at Cabin, Red Earth and Tommy Lakes, and have seen enough initial production data to believe that our projected first quarter exit targets will be achievable. We look forward to updating you as the year progresses.

(signed)

Matthew J. Brister
President and Chief Executive Officer
March 18, 2002

SME

EXPLORATION REVIEW



THE TOMMY LAKES PROPERTY WAS PURCHASED LATE IN 2000 FOR $30 MILLION, AND HAS DEVELOPED INTO THE COMPANY'S LARGEST SINGLE ASSET WITH ESTABLISHED RESERVES OF 72 BCFE AND AVERAGE PRODUCTION IN 2001 OF 9.9 MMCF/D AND 200 BBLS/D OF NATURAL GAS LIQUIDS.

UNDEVELOPED LAND

Storm has a large, high working interest, undeveloped land position focused in its core areas of activity. In 2001, our land base has increased by 11% to 252,926 net acres.

Undeveloped Land Holdings

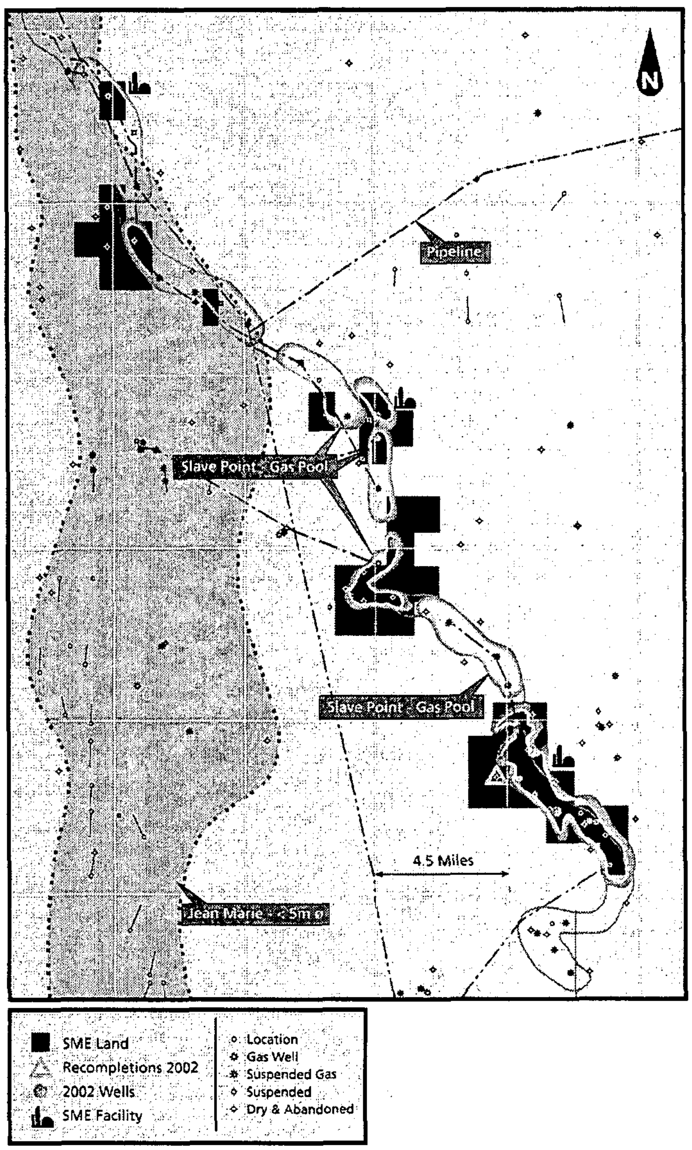
At December 31,	2001	2000	% Change
Gross acres	330,384	307,562	7
Net acres	252,926	228,450	11
Average working interest (%)	77	74	
Estimated value ($ millions)	16.32	10.89	50
Estimated value per net acre ($)	64.52	47.67	35

NORTHEASTERN BRITISH COLUMBIA

During 2001 Storm successfully diversified its asset base and growth potential with the development of two gas properties in northeastern British Columbia. These projects provide leverage to a second premium priced commodity and also provide a second core operating area with enough "owned" opportunities to deliver significant volume growth at a reasonable cost. Tommy Lakes and Kotcho represented 72% of our total 2001 gas production of 22.6 Mmcf/d. Our first quarter's activity in 2002 should double volumes from northeastern British Columbia to over 35 Mmcf/d.

At Cabin, we are developing a series of sour, high pressure gas pools along a dolomitized reef edge in the Devonian Slave Point formation. 3D seismic reduces the risk by allowing us to image the crestal portions and collapse features, leaving porous reservoir development and drilling problems as the main risks. We drilled two bank edge and one pinnacle reef test in 2001, with one successful well on production by breakup. The 2100 metre wells cost $1.4 million to drill and case and $250,000 to complete. The c-58-C well averaged 6.7 Mmcf/d and had proven developed producing reserves assigned of 10 Bcf. Our 2001 capital program at Cabin totaled over $10 million and included dehydration and disposal facilities at Louise and Kotcho and two large 3D seismic surveys. This winter's program will include two wells at Kotcho and two wells at Louise (1.5 net). On lands currently under our control we see at least four additional wells for next winter. Transportation and operating expenses averaged $1.10/Mcf in 2001 and should decrease with higher volumes and facility utilization in 2002.

CABIN

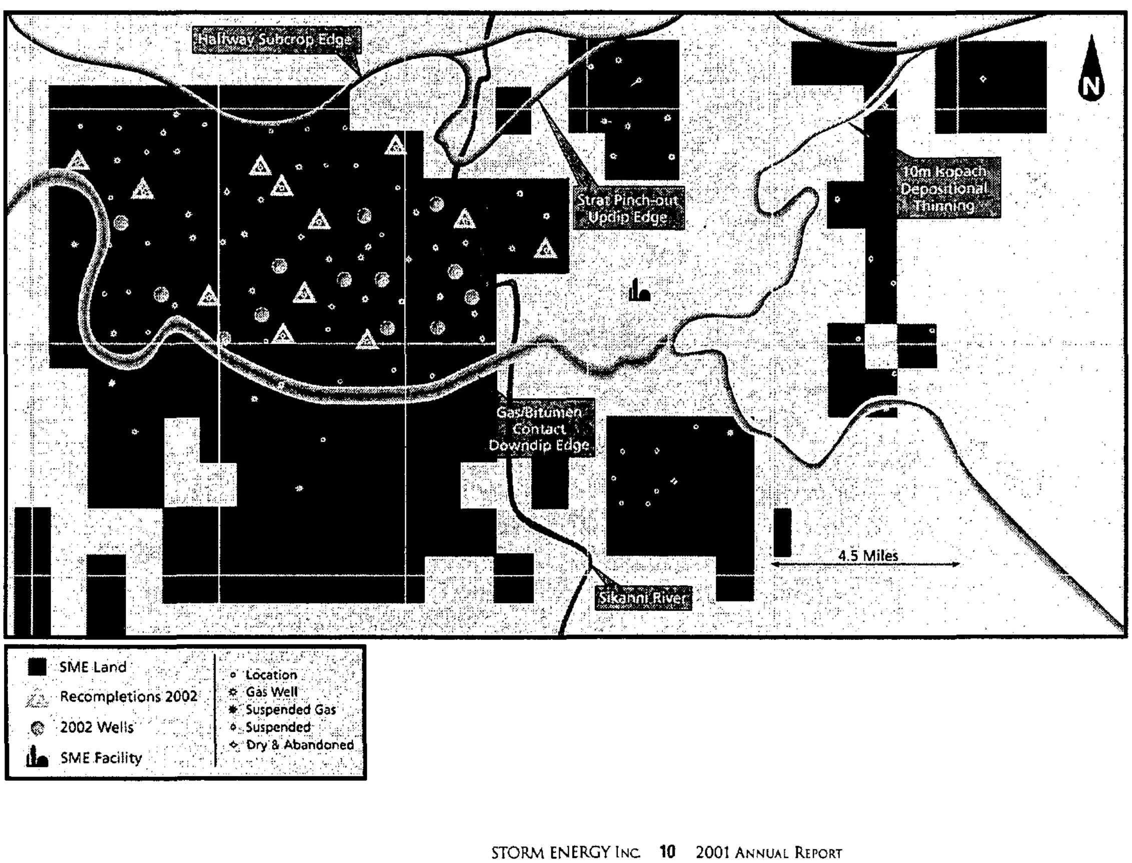


The Tommy Lakes property was purchased late in 2000 for $30 million and has developed into the Company's largest single asset with established reserves of 72 Bcfe and average production in 2001 of 9.9 Mmcf/d and 200 Bbls/d of natural gas liquids. Located northwest of Fort St. John, the 600 Bcf pool produces 59 Mmcf/d gross from an areally extensive blanket sand in the Triassic Halfway formation. Although the reservoir is thick (more than 10 metres) and continuous, its permeability is low, requiring all wells to be fracture stimulated to achieve average stabilized rates of 600-800 Mcf/d, with liquids recovered at 20 Bbls/Mmcf.

The largest impediment to aggressive development is the topographic constraints of the field's location beneath an incised plateau bordered by rivers that can only be crossed economically with an ice bridge in winter. Fortunately for our current and future development, significant pipeline, plant and road infrastructure were in place prior to our purchase. In fact, at current operating pressures, plant capacity is 54 Mmcf/d gross (31 Mmcf/d net) and we expect production volumes to double to 20 Mmcf/d net by the end of the first quarter 2002. After the completion of our aggressive first quarter 13 well drilling and 12 well recompletion program, we will still have 43,000 acres of undeveloped land, including more than 15 undrilled spacing units inside the defined productive limits of the field to support further development. Similar fields in Alberta are eventually downspaced with at least two wells per spacing unit when fully developed.

Wells cost $750,000 to drill and case and an additional $375,000 to complete with a large fracture stimulation. Transportation, processing and operating expenses to get the gas to the point of sale at Sumas have averaged $1.05/Mcf, but should drop in the future due to the benefit of higher volume and plant utilization in 2002.

TOMMY LAKES

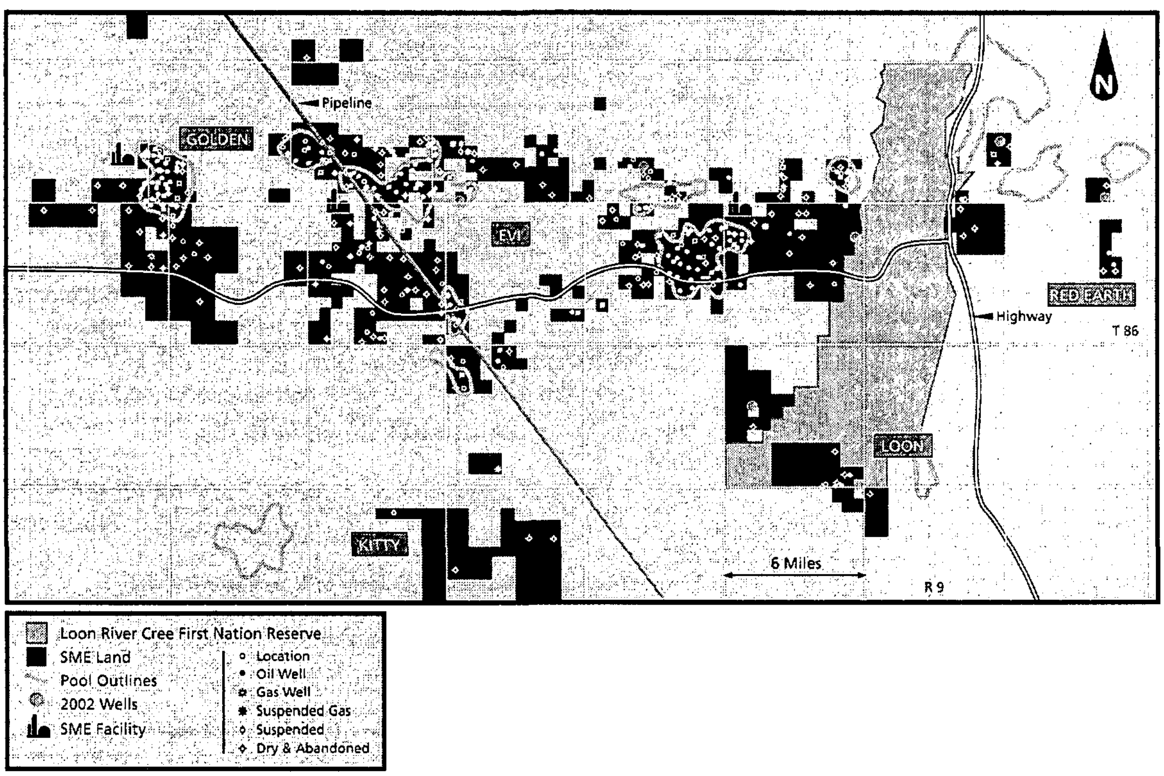


Our two British Columbia gas properties represented 57% of our Boe (6:1) volume growth from 2000 to 2001. We expect gas volumes to double to more than 35 Mmcf/d in 2002, increasing gas as a percent of our production mix to 48%. We anticipate several years of further development of our newest core area and will be seriously working toward adding to our gas exposure in northeastern British Columbia through exploration or acquisitions in 2002.

RED EARTH

Our Red Earth light oil project continued to be our most profitable asset and a strong volume growth contributor in 2001. Despite no acquisitions or significant exploration success, our 33 well drilling program successfully increased production by 49% and reserves by 14%, net of production. Average 2001 production rates of 5,886 Bbls/d and established reserves of 12.8 million Bbls support a reserve life index of six years. Drilling success was spread across Ogston, Red Earth, Evi West, Evi North, and Golden. Of particular note was the development of a new Slave Point pool at Evi West, a three well Granite Wash/Slave Point Limestone pool at Evi North, and a Granite Wash discovery at Red Earth late in the year. Using our 2001 performance as a measure of our ability to grow and continue to create value in this core area presents an encouraging picture. We added, on average, 160,000 Bbls of proved producing oil reserves per successful well and added reserves at approximately $7.30 per barrel.

RED EARTH



Operating costs averaged $4.47/Bbl, down 7% from last year. Our 38° API sweet crude sold for an average price of $38.19 CDN/Bbl, 99¢ off the Edmonton posted price of $39.18/Bbl and $15.00/Bbl higher than the average price for a heavier Lloyd blend. The premium price of our high quality crude and our low cost structure supported an average field netback of $23.25/Bbl, and a recycle ratio for Red Earth of over 3.0 times.

In 2001, we increased our undeveloped land position by 12% to 89,000 net acres and negotiated exclusive access to explore 35,000 acres of prime exploratory lands between our Loon Lake field and the Red Earth field in partnership with the Loon River First Nation. We are shooting a 25 square mile 3D seismic survey during the winter to evaluate the northern third of the block and hope to drill the initial test wells after breakup. We successfully added reserves, production and prospects on a new play for Storm with the development of Slave Point Limestone reservoirs at Ogston and Evi North. We have acquired prospective lands, and recognize some potential on our existing lands, for Bluesky/Gething gas and heavy oil at Seal and Red Earth. We may test two or three prospects on these plays in 2002.

The Loon Lake pool, discovered by Storm in 2000, continued to perform well in 2001. Production averaged 2,390 Bbls/d with watercuts increasing from less than 15% to 25% over the year. Ultimate recoverable reserves were increased to 4.25 Mmbbls or 58% of original oil in place of 7.4 Mmbbls. Our independent engineering evaluation estimates production will average 2,230 Bbls/d gross in 2002 and the pool is currently producing 2,700 Bbls/d. We have factored 25% production declines into our volume forecast and believe there is a reasonable chance the pool will continue to outperform our expectations.

As we did in 2001, in the absence of significant exploratory success in 2002, we expect to invest approximately half of Red Earth's net operating income in the area, drill 25-30 wells, and grow production and reserves by at least 10%. Our strategy for Red Earth over the next few years will be to continue to add and evaluate exploratory projects, to not over-capitalize our existing assets, to evaluate secondary zones that develop in the area, and to acquire assets that complement our existing position.

In response to air quality, solution gas flaring, and greenhouse gas emission concerns, Storm implemented a solution gas fired electrical power generation project at its main Evi battery in November 2001. We now conserve over 45% of the flared solution gas and generate over 2 Mw/hr of power. This represents a direct hedge against almost one half of our electrical power consumption. In 2001 the project cost just under $3 million and should payout in three years at average electricity prices of $40/Mw. We have plans to participate in two small projects at our area facilities in 2002 and will consider larger projects in the area as the opportunities arise. An intangible benefit to these expenditures may surface in the future as we try to limit greenhouse gas emissions under the Kyoto Protocol to be adopted by Canada later in 2002.

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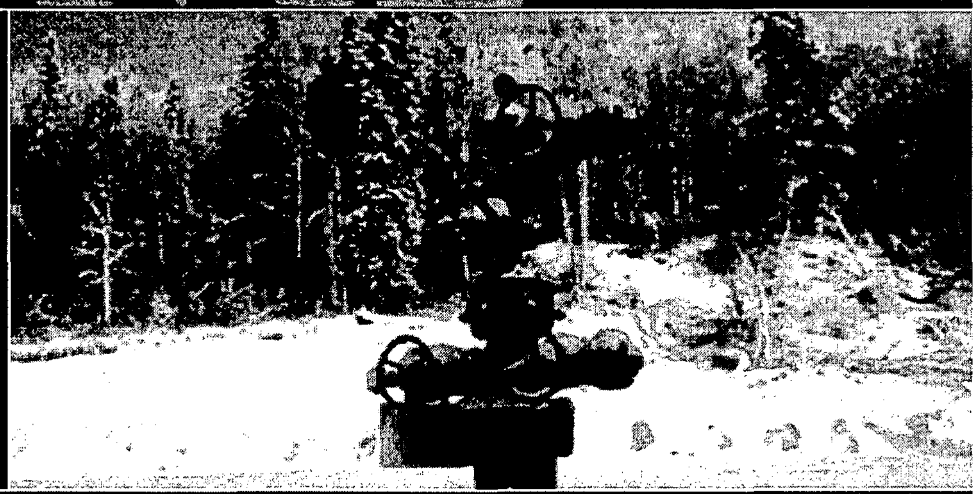
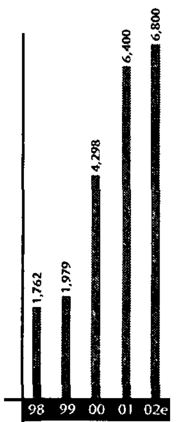
OPERATIONS REVIEW



We were able to increase our production volume by 74% (6:1) over 2000 levels through continued strong performance at Red Earth and the addition of a second core area which delivered strong gas production growth from northeast British Columbia.



Production
Liquids (Bbls/d)

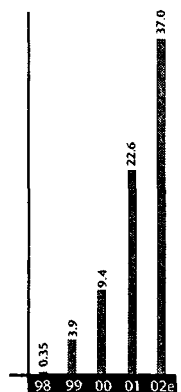
DRILLING ACTIVITY

Storm increased drilling activity by 31% in 2001 to 47 wells. Our average working interest remained very high at 80% and we operated over 85% of the wells we participated in. Red Earth activity increased marginally to 33 wells (versus 30 in 2000) and we commenced drilling in British Columbia for the first time in the Company's history with seven wells drilled in 2001.

For 2002, we expect to drill over 20 wells in the first quarter and 40 wells during the year. Winter activity will be focused at Tommy Lakes (9 wells) and Kotcho (4 wells) in northeast British Columbia and at Red Earth (7 wells). We expect to have one rig working from breakup until year-end at Red Earth. In addition, we currently plan to test prospects at Petitot, Sylvan and Pouce Coupe.

Drilling Results

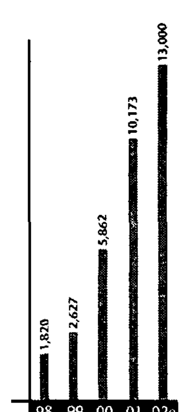
Year ended December 31,	2001		2000	
	Gross	Net	Gross	Net
Oil	23.00	19.70	23.00	20.77
Gas	8.00	5.19	2.00	1.25
Dry and abandoned	16.00	12.71	11.00	7.80
Total	47.00	37.60	36.00	29.82
Success ratio (%)	66		69	
Average working interest (%)	80		84	



Production
Gas (Mmcf/d)

PRODUCTION REVIEW

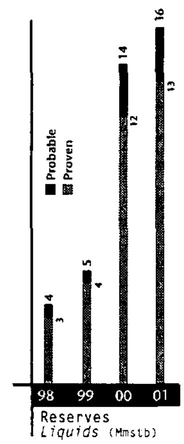
During 2001, we were able to increase our production volume by 74% (6:1) over 2000 levels through continued strong performance at Red Earth and the addition of a second core area which delivered strong gas production growth from northeast British Columbia. Over the last three years our production volumes have grown by a compounded rate of just under 80%. Although this rate will undoubtedly slow as the Company grows, we have a preliminary projection of 30% volume growth in 2002, to over 13,000 Boe/d (6:1). We have additional financial resources available to us to increase volumes through our internal program or property acquisitions as opportunities arise. Liquids volumes grew by almost 50% with over 90% of the volumes coming from Red Earth. Red Earth crude averages 38° API and less than 0.5% sulphur, qualifying it for a premium light sweet crude price, which averaged $38.19/Bbl in 2001. The profitability of Storm's liquids production relative to other liquids producers was magnified last year as the price differential between light and heavier crude widened. Our average liquids price saw a differential of only $0.99/Bbl off an Edmonton posted price of $39.18/Bbl versus a differential on a Lloyd blend heavy crude in eastern Alberta of approximately $15.00/Bbl.



Production
Boe (Boe/d 6:1)

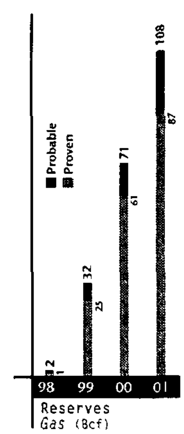
Our liquids operating expenses dropped 7% in 2001 to $4.24/Bbl. We are currently forecasting $4.31/Bbl for 2002. We have some excess capacity at Evi and Golden, but the Evi West facility is currently at capacity. The exploratory focus of our Red Earth program is shifting east and may require new facilities east of Loon Lake, depending on drilling success.

Gas volumes grew from 26% of our Boe volumes to 37% in 2001. Based on our initial projections, the mix will shift to 48% gas, 52% NGL's and light sweet crude for 2002. Equally important as the commodity balance is the geographic diversification achieved by now being able to rely on three separate plays in two core areas to deliver future growth. Tommy Lakes, acquired in late 2000, provided almost 10 Mmcf/d of incremental gas production accompanied by 200 Bbls/d of NGL's. During this winter, our first full season of activity, we should drill over a dozen new wells and recomplete a like number, with expectations of volumes doubling by breakup. At Cabin we saw volumes grow by over 5 Mmcf/d with one successful new well and a marginally successful recompletion. We expect to fill our Kotcho facility to capacity of 20 Mmcf/d gross by the end of the winter, growing our net volumes from the area to over 13 Mmcf/d and corporately to over 40 Mmcf/d. Gas operating expenses were essentially unchanged from 2000 at 55¢/Mcf and should not materially vary 2002. Capacity exists at the Tommy, Kotcho and Louise facilities to handle all incremental volumes projected to be added in 2002.



Production by Area

Year ended December 31,	2001				2000			
	Oil/NGL Bbls/d	Gas Mcf/d	Boe (10:1) Boe/d	Boe (6:1) Boe/d	Oil/NGL Bbls/d	Gas Mcf/d	Boe (10:1) Boe/d	Boe (6:1) Boe/d
Red Earth	5,886	–	5,886	5,886	3,962	–	3,962	3,962
Pouce Coupe	28	2,958	324	521	53	3,569	410	648
Sylvan Lake/Medicine River	282	2,754	557	741	232	2,760	508	692
Cabin/Kotcho/Louise	–	6,474	647	1,079	–	1,084	108	181
Tommy Lakes	204	9,906	1,195	1,855	36	1,632	199	308
Other	–	548	55	91	15	341	49	71
Total	6,400	22,640	8,664	10,173	4,298	9,386	5,236	5,862

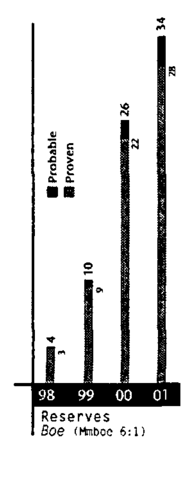


CRUDE OIL & NATURAL GAS RESERVES

The reserves of Storm's oil and natural gas properties were evaluated as at December 31, 2001 by Paddock Lindstrom & Associates Ltd., an independent petroleum engineering firm. As well, a committee of independent directors of Storm met with Paddock to validate the methodology used to evaluate Storm's 2001 year end reserve volumes and values. The estimate of the value of future production is stated before a provision for income taxes or overhead costs and is dependent on many factors, a major one being the forecast of future commodity prices. It should not be assumed that the estimated future net revenue derived from this report represents the fair market value of the reserves that were evaluated. The following tables provide information based on the figures contained in the Paddock report dated February 12, 2002.

Estimated reserves of **Oil, Gas and NGL's**
(Based on Escalating Price and Cost Assumptions)[2]

	Oil (Mstb)		Gas (Mmcf)		NGLs (Mstb)	
(At December 31, 2001)	Gross[1]	Net[1]	Gross[1]	Net[1]	Gross[1]	Net[1]
Proved producing	10,987	9,155	62,262	48,083	1,144	908
Proved non-producing	507	457	7,615	6,262	30	25
Total proved developed	11,494	9,612	69,877	54,345	1,174	933
Proved undeveloped	290	240	17,206	13,466	380	315
Total proved	11,784	9,852	87,083	67,811	1,554	1,248
Probable additional unrisked	2,292	1,942	20,931	16,094	179	142
Proved and probable unrisked	14,076	11,794	108,014	83,905	1,733	1,390
Reduction for risk[3]	(1,146)	(971)	(10,465)	(8,047)	(89)	(71)
Proved and probable risked	12,930	10,823	97,549	75,858	1,644	1,319



Discounted Value of Estimated Future Net Revenue Before Income Taxes
(Based on Escalating Price and Cost Assumptions)(2)
($ thousands)

(At December 31, 2001)	Undiscounted	Discounted at the rate of 10%	15%	20%
Proved producing	375,693	250,462	216,673	191,914
Proved non-producing	25,324	14,093	11,176	9,122
Total proved developed	401,017	264,555	227,849	201,036
Proved undeveloped	49,088	23,653	18,405	14,902
Total proved	450,105	288,208	246,254	215,938
Probable additional unrisked	92,798	45,549	35,411	28,641
Proved and probable unrisked	542,903	333,757	281,665	244,579
Reduction for risk(3)	(46,398)	(22,774)	(17,705)	(14,320)
Proved and probable risked	496,505	310,983	263,960	230,259

(1) "Gross Reserves" are net of working interests owned by others and prior to deduction of Crown, freehold and other royalties. "Net Reserves" are net of all interests owned by others including royalties.

(2) For the escalating price and cost scenario, the price forecast used, subject to adjustment for the actual quality of oil produced or for gas, subject to the terms of the actual gas contract used to market the gas reserves, was the January 2002 price forecast used by Paddock Lindstrom & Associates Ltd. Prices were escalated at 2% per year after 2016 and costs were escalated at 2% per year from 2002.

(3) The estimated volumes and values of the estimated reserves and estimated value of future net revenue from probable reserves has been reduced by 50% to allow for risk.

Escalating Price Forecast

	WTI at Cushing $US/Bbl	Edmonton Reference Price $/Bbl	AECO C $CDN/MMBTU	SUMAS Spot $CDN/MMBTU	Henry Hub $US/MMBTU
2002	21.00	32.31	3.76	4.27	2.85
2003	21.50	32.55	4.30	4.83	3.25
2004	21.93	32.68	4.43	4.93	3.40
2005	22.37	33.33	4.50	4.96	3.45
2006	22.82	34.00	4.56	4.98	3.50
2007	23.27	34.68	4.65	5.04	3.57
2008	23.74	35.37	4.74	5.10	3.64
2009	24.21	36.08	4.84	5.20	3.71
2010	24.70	36.80	4.93	5.31	3.79
2011	25.19	37.54	5.03	5.41	3.86

2001 Reserve Reconciliation
(Escalating Dollar and Before Royalties)

	Crude oil (Mbbls)			Natural gas (Mmcf)			NGL's (Mbbls)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
December 31, 2000	10,669	2,132	12,801	60,476	10,533	71,009	1,099	161	1,260
Additions during 2001	3,802	1,132	4,934	22,137	11,777	33,914	224	14	238
Production	(2,211)	–	(2,211)	(8,263)	–	(8,263)	(125)	–	(125)
Revisions	(452)	(968)	(1,420)	12,733	(1,379)	11,354	356	4	360
Dispositions	(24)	(4)	(28)	–	–	–	–	–	–
December 31, 2001	11,784	2,292	14,076	87,083	20,931	108,014	1,554	179	1,733

FINDING AND ON STREAM COSTS

The most important measure of our profitability that is within our control, is our cost to find, develop and bring on stream new reserves.

In an effort to conform to the disclosure standards that will be coming into effect next year, we are reporting our 2001 results, and restating our 2000 and 1999 results, using the methodology outlined in the Canadian Securities Administrators proposed National Instrument No. 51-101. The policy requires the inclusion of current year's exploration costs, development costs, and the change in future development costs from the previous year's report in the numerator, with the additions to proved and probable reserves equated on a 6 Mcf = 1 Bbl basis as the denominator. We have excluded the capital spent directly on the electrical power generation project as this expenditure has no reserves associated with it and is more properly a midstream investment. Our proven finding and on stream costs for 2001 were down 7% from the previous year at $6.67/Boe.

Two variances from last year's performance were the increased percentage of gas reserves in reserve additions and the reduced contribution of acquisitions as a percent of finding costs. The cost of services increased in 2001, over 2000, as a result of higher levels of industry activity and utilization rates. Undeveloped land and acquisition costs were also inflated as a result of increased cash flows and commodity price expectations. Our inability to complete a significant acquisition in 2001, which to a degree was disappointing, was the direct result of our discipline in pricing acquisitions at a level competitive with our internal finding and on stream costs.

We believe our finding and on stream costs will be sustainable at a level comparable to the last two years for a number of reasons. Our program is focused in three core areas where we have significant accumulated expertise, an asset focus, sunk costs in land, seismic and facilities and a proven cost structure. Commodity prices and cash flows are both expected to be lower which should lessen competition for land and acquisitions and lower utilization rates will reduce the cost of services.

Finding and On Stream Costs

($ thousands, except where noted)

Year ended December 31,	2001	2000	1999	3 Year Total
Finding Costs				
Land and seismic	8,069	9,592	2,048	
Drilling	23,802	19,913	6,633	
Completions	5,700	5,266	2,564	
Total Finding Costs	37,571	34,771	11,245	83,587
On Stream Costs				
Acquisitions, net of dispositions	(584)	50,974	21,170	
Equipping and recompletions	9,905	5,413	1,501	
Pipeline and facilities	14,554	9,400	2,290	
Field inventory	1,292	547	57	
Total On Stream Costs	25,167	66,334	25,018	116,519
Change in Future Development Costs from previous year				
Proved Costs	2,066	8,714	5,471	16,251
Proved and Probable Costs	4,407	12,166	5,540	22,113
Total Costs Used in Finding and On Stream Calculation				
Proved Costs	64,804	109,819	41,734	216,357
Proved and Probable Costs	67,145	113,271	41,803	222,219
Reserve Additions (Mboe @ 6:1)				
Proved	9,718	15,329	6,570	31,617
Proved and Probable	11,628	17,760	7,405	36,794
Finding and On Stream Cost (6:1)				
Proved	6.67	7.16	6.35	6.84
Proved and Probable	5.77	6.38	5.65	6.04
Reserve Additions (Mboe @ 10:1)				
Proved	7,393	12,742	4,885	25,021
Proved and Probable	8,610	14,898	5,371	28,879
Finding and On Stream Cost (10:1)				
Proved	8.76	8.62	8.54	8.65
Proved and Probable	7.80	7.60	7.78	7.69

RESERVE RECYCLE RATIO

Storm's premium priced light sweet crude oil and natural gas production and low operating cost structure generated a very strong field netback per Boe during 2001. When that netback is divided by our proved and the proved and probable finding and on stream costs per Boe, we get a measure of our ability to grow our underlying reserve base from the revenue that we generate. Storm's 2001 recycle ratio, at 3.4 times for proved reserves and 3.9 times for proved and probable reserves, indicates that by reinvesting the proceeds from every barrel that we produced from our reserve base we were able to add almost three and one half new barrels.

Reserve Recycle Ratio

Year ended December 31,	2001	2000
Average field netback		
Per Boe (10:1) ($)	26.46	27.89
Per Boe (6:1) ($)	22.55	24.99
Reserve addition and on stream costs per Boe (10:1) ($)		
Proved	8.76	8.62
Proved and Probable	7.80	7.60
Reserve recycle ratio		
Proved	3.0	3.2
Proved and Probable	3.4	3.7
Reserve addition and on stream costs per Boe (6:1) ($)		
Proved	6.67	7.16
Proved and Probable	5.77	6.38
Reserve recycle ratio		
Proved	3.4	3.5
Proved and Probable	3.9	3.9

CORPORATE CITIZENSHIP

Storm has a responsibility to our employees, shareholders, contractors and the communities in which we operate to carry out our activities in a safe manner and to minimize our impact on the environment. In this regard, we have corporate policies governing our activities that meet or exceed the required regulatory standards. We carry out regular independent safety and environmental audits and use the results as a component in evaluating an individual's performance and determining compensation. During 2001, we recorded three safety incidents, one of which resulted in a serious injury. We will be trying to develop better tools for measurement and encouraging safe practices in an attempt to better gauge and continue to improve on our safety performance.

The power generation project at our Evi 4-36 facility successfully reduced our flared solution gas in the Red Earth area by 45% (0.7 Mmcf/d) resulting in improved air quality through a significant reduction in greenhouse gas emissions from our operations. We expect to develop at least one additional project involving electrical power generation from flared solution gas at Red Earth in 2002.

Storm is an active supporter of the communities in which we operate. We attempt to share the economic benefits of resource development by hiring and contracting locally wherever possible. We expect to see an increased involvement in the Fort Nelson and Fort St. John region, as part of our activity in those areas in 2002.

Storm and its employees contributed time and over $100,000 to a number of not-for-profit and charitable organizations in 2001. The focus of our giving was on health, education, and social services initiatives, split 60/40 between Calgary and field locations. We participated for the third year in a partnership program with Christine Meikle School in northeast Calgary.

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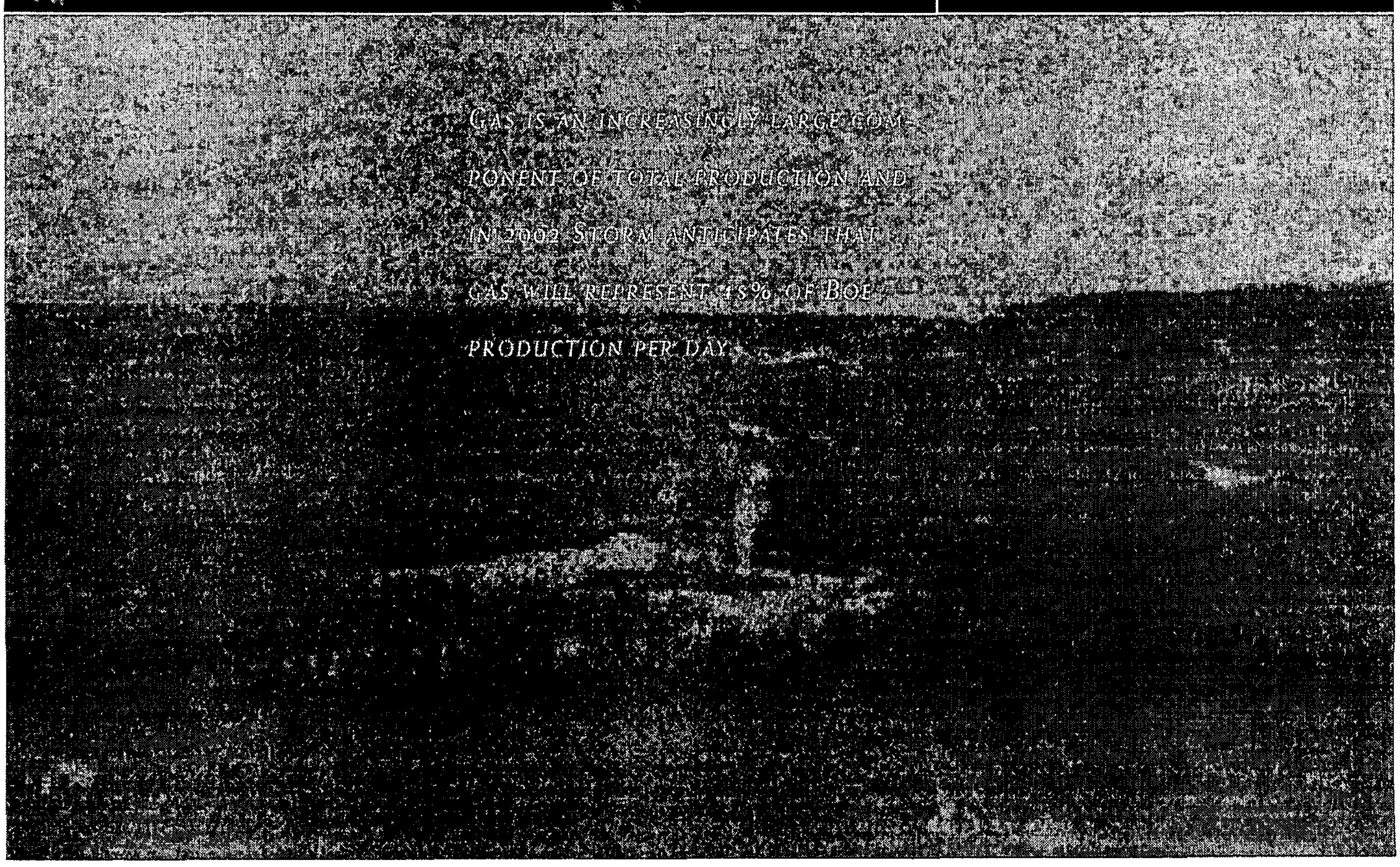
MANAGEMENT'S DISCUSSION & ANALYSIS



Gas is an increasingly large component of total production and in 2002 Storm anticipates that gas will represent 15% of Boe production per day.

The information set out below should be read in conjunction with the audited consolidated financial statements of the Company included in this Annual Report.

MEASUREMENT AND EQUIVALENTS

- all financial amounts are stated in thousands of Canadian dollars except where otherwise indicated.
- conversion of natural gas volumes to a crude oil equivalent has been made using a ratio of 6 thousand cubic feet to 1 barrel of crude oil. Where comparison is useful certain measurements using a 10 to 1 conversion ratio have been included.
- volumetric measurements correspond to American Petroleum Institute standards.
- land ownership is measured in acres.
- for reporting purposes natural gas liquids have been aggregated with oil.

HIGHLIGHTS

After the considerable growth of the Company's asset base through acquisition in the prior year, 2001 was a year of consolidation with corporate focus being directed to exploiting newly acquired properties. Although the Company examined a number of acquisition opportunities, none satisfied the Company's acquisition criteria, particularly in the area of price. Nevertheless, year on year production volumes grew by 74% (6:1) compared to 123% in 2000. The absolute increase was 4,311 Boe per day, the largest such increase since the Company was reorganized in late 1998. In addition, gas is an increasingly large component of total production and in 2002 Storm anticipates that gas will represent 48% of Boe (6:1) production per day. The first part of 2001 was characterized by high product prices, particularly for natural gas, and correspondingly high netbacks and cash flow. It also saw the acquisition of many of Storm's competitors with the result that there are a limited number of companies comparable to Storm in terms of size, operational and financial quality, and depth of management. However, the favourable product price environment was not sustainable and the erosion of product prices, which began well before the events of September 11 and the formal recognition of a North American recession, continued through to the end of 2001. Although cash flow has diminished, Storm's conservative approach to financing provides the Company with the resilience to maintain its exploration and development programs and to take advantage of the opportunities for growth which will present themselves in 2002. These opportunities will come from lower product prices, fewer potential buyers, and sellers motivated to rationalize property holdings after the surge of acquisitions in 2001. These conditions are likely to create a market environment favourable to well positioned companies such as Storm.

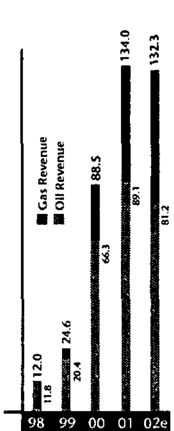
KEY PERFORMANCE MEASUREMENTS

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Production income	134,028	88,529	51
Cash flow from operations	77,707	48,999	59
- per share – diluted ($)	2.72	2.05	33
Net income	32,142	18,339	75
- per share – diluted ($)	1.13	0.77	47
Capital expenditures, net	65,751	101,352	(35)
Return on average capital employed (%)	25	20	25
Long term debt, (including working capital deficiency)	65,990	78,466	(16)
Shareholders' equity	91,055	58,389	56
Return on average shareholders' equity (%)	43	40	8
Net asset value	269,920	207,215	30
- per share – diluted ($)	9.10	7.08	29
Diluted shares outstanding (000's)	29,662	29,277	1

PRODUCTION INCOME

Production income increased by 51% in 2001 as a result of both volume increases throughout the year and higher product prices, particularly gas, for the first six months. Oil and liquids represented 66% of revenue before forward sale recognition and natural gas 34%. Volume increases resulted from the inclusion of a full year's production from acquisitions made in 2000 at Kitty, Golden and Evi in the Red Earth area of north central Alberta, and at Tommy Lakes in northeastern British Columbia. In addition, exploitation programs at Red Earth and in northeastern British Columbia resulted in volume additions considerably in excess of declines.



Production Income ($Millions)

Revenues

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Crude oil and natural gas liquids	88,565	69,430	28
Natural gas	46,023	24,951	84
Income (loss) from hedging	(560)	(5,852)	(90)
Total production income	134,028	88,529	51
Volumes			
Crude oil – Bbls/day	6,400	4,298	49
Natural gas – Mcf/day	22,640	9,386	141
Total production – Boe/day 6:1	10,173	5,862	74
Total production – Boe/day 10:1	8,664	5,236	65

HEDGING GAINS AND LOSSES

Included in production income are gains and losses from hedge contracts. The Company enters into such contracts when fluctuations in commodity prices or interest rates or foreign exchange volatility will result in capital programs being compromised or debt levels exceeding internal guidelines. Details of hedging income and losses are as follows:

Hedging gains and losses
($ thousands, except where noted)

Year ended December 31	2001	2000
Increase (decrease) in oil revenues	615	(3,143)
Increase (decrease) in gas revenues	(1,175)	(2,709)
Hedge gain (loss)	(560)	(5,852)

Details of hedges outstanding during 2001 and 2000 are as follows:

Natural gas and foreign exchange	Floor	Ceiling
November 1, 2000 – October 31, 2001		
2,000 GJ/day at AECO	$CDN 4.00	$CDN 7.25
7 Mmbtu/day at Sumas	$US 4.00	$US 5.80
Foreign currency - $US 850,000 per month at $CDN 0.6739		
November 1, 2001 – October 31, 2002		
7 Mmbtu/day at Sumas	$US 3.50	$US 5.10
Foreign currency - $US 735,000 per month at $CDN 0.6792		

Crude oil
August 1, 2001 – December 31, 2001, 1,000 Bbls/day at $CDN 40.12/Bbl
January 1, 2002 – December 31, 2002, 1,000 Bbls/day at $CDN 37.63/Bbl

Subsequent to December 31, 2001, the Company entered into a financial collar contract for the period April 1, 2002 to March 31, 2003. Under the contract the Company has a floor price of $CDN 2.75/GJ in respect of 9,000GJ/day at AECO for the period April 1, 2002 to October 31, 2002. For the period November 1, 2002 to March 31, 2003 the Company has a ceiling price of $CDN 5.15/GJ in respect of 12,755 GJ/day also at AECO. The Company's existing gas hedges and foreign currency contract were entered into to mitigate balance sheet risk with respect to the financing of the Tommy Lakes property acquisition in November 2000. The additional hedge entered into in 2002 is designed to provide price support to gas production from Tommy Lakes being tied in during the first quarter of 2002.

ROYALTIES AND ALBERTA ROYALTY TAX CREDIT

Royalties, being Crown, freehold and overriding royalties, increased by 39% in 2001 over the prior year, before the Alberta royalty tax credit. Crown royalties are paid to provincial governments in Alberta and British Columbia; freehold royalties are paid to freehold leaseholders and overriding royalties are paid to joint venture partners. Higher royalties resulting from increased production were offset by a lower royalty rate, primarily attributable to lower gas prices in the latter half of the year. The Alberta royalty tax credit is a reduction in Alberta provincial taxes based on Crown royalties paid in Alberta. It declined as a percentage of revenue as a consequence of the Company's increasing exposure to activity in British Columbia. Storm is eligible for the maximum Alberta Crown royalty coverage under the program of $2,000,000, resulting in a cash recovery against royalties paid of $573,000.

Royalties

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Oil	25,367	19,998	27
Gas	11,111	6,284	77
Total royalties	36,478	26,282	39
Average royalty per sales unit			
Oil - $ per Bbl	10.86	12.71	(15)
Gas - $ per Mcf	1.35	1.83	(26)
Total - $ per Boe 6:1	9.82	12.28	(20)
Total - $ per Boe 10:1	11.54	13.71	(16)
Royalties as a percentage of production income			
Oil	29	29	
Gas	24	25	
Total royalty percentage	27	28	

OTHER INCOME

Other income includes income received by Storm for treating and processing third party oil and gas at the Company's production facilities as well as overriding royalties. Such income amounted to $1,332,000 in 2001 and was 17% higher than the previous year.

PRODUCTION EXPENSES

Production expenses increased 58% in 2001 compared to the prior year. The increase is due to higher production levels. In addition, higher costs for electrical power prevailed during the first part of the year. In December 2001 the Company began delivery of electrical power from two generators located at Red Earth. Approximately 2 megawatts per hour of power is generated which is sold at spot prices. In addition, the Company extracts approximately 70 Bbls/d of natural gas liquids which would otherwise be flared. A full year's contribution from the power generation facility is expected to result in a $0.31/Bbl reduction in production costs from these facilities. In 2002 production costs are expected to average $4.31 per barrel and $0.55 per Mcf respectively.

Production expenses

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Oil	9,898	7,171	38
Gas	4,514	1,940	133
Total production expenses	14,412	9,111	58
Average production cost by commodity			
Oil - $ per Bbl	4.24	4.56	(7)
Gas - $ per Mcf	0.55	0.56	(2)
Total production cost per Boe 6:1	3.88	4.25	(9)
Total production cost per Boe 10:1	4.56	4.75	(4)

GENERAL AND ADMINISTRATIVE COSTS

Gross general and administrative costs increased by 40% in 2001 over the prior year. Increases were primarily due to a higher staff level and the part year impact of considerably increased insurance and accomodation costs. Overhead recovery costs, which are charged to partners as a recovery of overhead on capital projects, are applied as a reduction of gross general and administrative costs. The amount of such recoveries is determined by a standard industry formula and use of recoveries to reduce general and administrative costs also corresponds to industry practice. Recoveries amounted to $2,192,000 in 2001 and $1,623,000 in 2000. The Company does not capitalize any part of its general and administrative costs. Costs per Boe at 6:1 decreased to $0.73 in 2001 from $0.88 in 2000. The reduction reflects scale benefits as production levels increase and general operating efficiencies. In 2002 general and administrative costs are expected to total $2,686,000 or $0.60 per Boe at 6:1 and $0.70 per Boe at 10:1.

General and administrative costs

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Gross general and administrative costs	4,903	3,499	40
Overhead recoveries	(2,192)	(1,623)	35
Net general and administrative costs	2,711	1,876	45
Net general and administrative costs per Boe 6:1	0.73	0.88	(17)
Net general and administrative costs per Boe 10:1	0.86	0.98	(12)

INTEREST ON LONG TERM DEBT

Interest expense increased to $4,213,000 in 2001 from $3,288,000 reflecting higher outstanding long term debt in 2001 resulting from debt financed acquisitions in 2000. Interest rates on long term debt averaged 6.2% compared to 7.4% in 2000. No interest is capitalized. For 2002 interest expense is expected to amount to $2,289,000, based on an expected interest rate of 4.5%.

Interest on long term debt

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Interest expense	4,213	3,288	28
Interest expense per Boe 6:1	1.13	1.54	(26)
Interest expense per Boe 10:1	1.33	1.72	(23)
Average long term debt outstanding	68,020	44,568	53
Average interest rate (%)	6.2	7.4	(16)

DEPLETION AND DEPRECIATION

Depletion and depreciation charges for 2001 amounted to $21,022,000 compared to $12,961,000 for 2000. The increase in the depletion and depreciation charge is attributable to increased production and to the inclusion of a full year's depreciation charge on processing facilities constructed on the Company's gas properties in northeastern British Columbia late in 2000.

Depletion and depreciation

($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Depletion and depreciation	21,022	12,961	62
Depletion and depreciation per Boe 6:1	5.66	6.06	(7)
Depletion and depreciation per Boe 10:1	6.65	6.76	(2)
Depletion and depreciation rate (%)	12	9	

PROVISION FOR SITE RESTORATION AND ABANDONMENT

Storm's provision for site restoration and abandonment for 2001 amounted to $1,452,000 compared to $663,000 for 2000. The increase in the provision is attributable to the growing importance to the Company of its gas properties in northeastern British Columbia, where the remote location will result in higher abandonment costs.

Provision for site restoration and abandonment
($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Site restoration and abandonment	1,452	663	119
Site restoration and abandonment per Boe 6:1	0.39	0.31	26
Site restoration and abandonment per Boe 10:1	0.46	0.35	31

INCOME AND OTHER TAXES

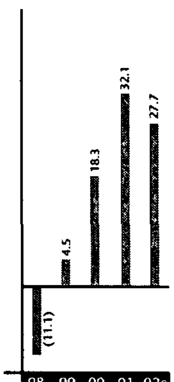
Future income tax amounted to $23,091,000 compared to $17,036,000 for 2000 or 41.5% of pre-tax income compared to 47.6%. The reduction in the effective tax rate is principally due to a reduction in the Alberta provincial tax rate. Large corporations tax is based on taxable capital employed by the Company and the increase results from the Company's growth in 2001.

Income and other taxes
($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Future income tax	23,091	17,036	36
Large corporations tax	413	410	1
Total income and other taxes	23,504	17,446	35

Estimated tax pools ($ thousands)	Amount	Rate of Claim
Canadian oil and gas property expense (COGPE)	60,387	10%
Canadian exploration expense (CEE)	515	100%
Canadian development expense (CDE)	25,629	30%
Undepreciated capital cost (UCC)	50,567	7% - 100%
Total	137,098	

NET INCOME



Net Income
($Millions)

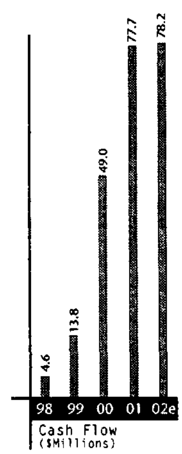
Net income for the year amounted to $32,142,000 compared to the amount reported for 2000 of $18,339,000. Diluted per share amounts were $1.13 compared to $0.77. Based on Company generated product pricing forecasts, production increases and the Company's controllable cost structure, net income for 2002 is forecasted to be $27.7 million or $0.93 per diluted share.

Net income
Year ended December 31

($ thousands, except where noted)	Net income	Diluted per share ($)
2001	32,142	1.13
2000	18,339	0.77
1999	4,513	0.16

CASH FLOW FROM OPERATIONS

Cash flow from operations, measured as net income adjusted for non-cash charges, grew by 59% to $77,707,000 in 2001 from $48,999,000 in 2000. Cash flow is the principal source of funding for Storm's capital programs. In 2001 capital expenditures amounted to 85% of cash flow, compared to 2000 where capital expenditures were more than double cash flow, primarily as a result of core area property acquisitions which totalled $51 million. Storm anticipates that cash flow for 2002 will amount to $78 million or $2.73 per diluted share.



Cash flow from operations
Year ended December 31

($ thousands, except where noted)	Cash flow	Diluted per share ($)
2001	77,707	2.72
2000	48,999	2.05
1999	13,813	0.51

CASH FLOW SENSITIVITIES

The quality of the Company's predictions of future earnings and cash flows is subject to a number of factors outside of the Company's control. References to 2002 net income and cash flow assume that the price realized for liquids will reflect a West Texas Intermediate price per barrel of oil of $US 22.00 and a realized gas price to the Company of $CDN 3.45/Mcf. The impact of changes to these prices and variations in other factors used to estimate future results are set out below.

2002 Cash Flow Sensitivities	2002 Assumptions	Cash Flow ($'000s)	Diluted Cash Flow per share (¢)
Change of US$1.00/Bbl in WTI price	22.00	2,197	7.4
Change in oil production of 100 Bbls/d	6,429	750	2.5
Change of CDN $0.10/Mcf in gas price	3.45	1,142	3.9
Change in gas production of 1 Mmcf/d	37	841	2.8
Change of $0.01 in $US/$CDN exchange rate	0.65	756	2.5
Change of 1% in interest rate	4.5	510	1.7

FIELD AND CASH FLOW NETBACKS

The table below sets out Storm's operating results on a Boe basis at a field and cash flow level.

Field and cash flow netbacks ($/Boe)

	6:1			10:1		
Year ended December 31	**2001**	2000	% Change	**2001**	2000	% Change
Field price	**36.25**	44.11	(18)	**42.56**	49.25	(14)
Hedging gain (loss)	**(0.15)**	(2.73)	(95)	**(0.18)**	(3.05)	(94)
Royalties	**(9.82)**	(12.28)	(20)	**(11.54)**	(13.71)	(16)
Alberta royalty tax credit	**0.15**	0.14	7	**0.18**	0.15	20
Production expenses	**(3.88)**	(4.25)	(9)	**(4.56)**	(4.75)	(4)
Field netback	**22.55**	24.99	(10)	**26.46**	27.89	(5)
Other income	**0.36**	0.53	(32)	**0.42**	0.59	(29)
General and administrative	**(0.73)**	(0.88)	(17)	**(0.86)**	(0.98)	(12)
Interest	**(1.13)**	(1.54)	(26)	**(1.33)**	(1.72)	(23)
Income and other taxes	**(0.11)**	(0.19)	(42)	**(0.13)**	(0.21)	(38)
Cash flow net back	**20.94**	22.91	(8)	**24.56**	25.57	(4)
Depletion and depreciation	**(5.66)**	(6.06)	(7)	**(6.65)**	(6.76)	(2)
Site restoration and abandonment	**(0.39)**	(0.31)	26	**(0.46)**	(0.35)	31
Future income tax	**(6.22)**	(7.96)	(22)	**(7.30)**	(8.89)	(18)
Net income	**8.67**	8.58	1	**10.15**	9.57	6

CAPITAL EXPENDITURES

Capital expenditures for 2001 totaled $67,160,000 before proceeds from minor dispositions of $1,409,000, compared to expenditures of $105,814,000 and dispositions of $4,462,000 in 2000. Expenditures in 2000 included $51,300,000 in major property acquisitions. There were no similar major outlays in 2001. However field program costs in 2001 increased by 23% over the prior year amount. Capital expenditures in the final quarter 2001 amounted to $18,633,000, or 28% of the annual total, as a consequence of weather conditions in northeastern British Columbia favouring an early start to the Company's winter drilling program. As a consequence, approximately $7.6 million scheduled to be spent in the first quarter of 2002 was spent in the final quarter of 2001. A preliminary estimate of capital expenditures for 2002 amounts to $40.4 million.

Net capital expenditures
($ thousands, except where noted)

Year ended December 31	2001	2000	% Change
Land	4,672	2,880	62
Seismic	3,397	6,712	(49)
Drilling and completion	29,502	25,179	17
Total exploration and development	37,571	34,771	8
Facilities, equipment and workovers	27,306	14,813	84
Acquisitions	825	55,436	(99)
Dispositions	(1,409)	(4,462)	(68)
Net operations	64,293	100,558	(36)
Field inventory	1,292	547	136
Administrative assets	166	247	(33)
Net capital expenditures	65,751	101,352	(35)

TOTAL DEBT

Debt is the total of the Company's working capital deficiency and its revolving line of credit. Working capital deficiency results from the active operated field program and high working interest position, resulting in amounts due to suppliers under capital programs being included in accounts payable. At December 31, 2001, the Company had available a revolving bank line of credit in the amount of $90,000,000, which bears interest at rates approximating the bank's prime rate. The Company's policy is to maintain debt levels not exceeding 1.5 times projected annualized cash flow. Debt levels for 2001 and the projected level for 2002 are well within this guideline.

Total debt
($ thousands, except where noted)

At December 31	2001	2000	% Change
Working capital deficiency	10,981	6,703	64
Long term debt	55,009	71,763	(23)
Total debt	65,990	78,466	(16)
Cash flow	77,707	48,999	59
Debt to cash flow	0.8:1	1.6:1	

NET ASSET VALUE

Net asset value and net asset value per diluted share at December 31, 2001 increased by 30% and 29%, respectively, over the prior year. The increase is due to additions to reserves resulting from field exploration programs. Established reserves increased by 28%, offset by a reduction in reserve value to $12.78 per Boe from $13.82 per Boe at the end of 2000. This reduction is due to the lower pricing regime used in the 2001 year end independent reserve valuation compared to pricing used in the prior year's report. The increase in the Company's undeveloped acreage and reduced debt also contributed to increased net asset values.

Year end net asset value per diluted share

($ thousands, except where noted)

At December 31	2001	2000	% Change
Present value of established reserves, discounted at 10%	310,983	269,355	15
Undeveloped acreage	16,318	10,891	50
Long term debt	(55,009)	(71,763)	(23)
Working capital deficiency	(10,981)	(6,703)	64
Proceeds on exercise of stock options/warrants	8,609	5,435	58
Net asset value	269,920	207,215	30
Diluted shares outstanding at year end ('000)	29,662	29,277	1
Net asset value per diluted share	9.10	7.08	29

COMMON SHARE TRADING ACTIVITY

The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the common shares of Storm for the periods indicated, as reported by sources that the Company believes to be reliable.

Common Share Trading Summaries

($ except volume)

2001	High	Low	Volume
1st Quarter	9.00	5.70	5,548,282
2nd Quarter	12.00	8.35	5,564,522
3rd Quarter	9.85	7.55	1,529,348
4th Quarter	10.75	7.60	5,067,655
Total			17,709,807
Year End Closing Price	9.50		
2000			
1st Quarter	3.50	2.35	4,569,229
2nd Quarter	6.20	3.15	3,345,507
3rd Quarter	6.15	5.05	3,310,415
4th Quarter	5.95	5.00	1,362,683
Total			12,587,834
Year End Closing Price	5.80		

QUARTERLY INFORMATION

Summarized results for the fourth quarter of the year are set out below along with results for the preceding three quarters.

	2001					2000				
Quarterly results – financial										
($ thousands, except where noted)	Q1 '01	Q2 '01	Q3 '01	Q4 '01	Total	Q1 '00	Q2 '00	Q3 '00	Q4 '00	Total
Oil and gas revenues	43,233	38,049	28,379	24,927	134,588	12,890	17,984	25,552	37,955	94,381
Cash flow from operations	22,987	21,730	17,752	15,238	77,707	7,133	9,418	13,605	18,843	48,999
Per share diluted	0.81	0.75	0.62	0.55	2.72	0.27	0.36	0.57	0.69	2.05
Net income	9,256	9,486	6,130	7,270	32,142	2,350	3,536	5,158	7,295	18,339
Per share diluted	0.32	0.34	0.21	0.26	1.13	0.09	0.14	0.22	0.27	0.77
Capital expenditures,net	27,206	6,866	13,047	18,632	65,751	8,418	30,538	14,633	47,763	101,352
Total debt	82,677	67,618	62,760	65,990	65,990	33,173	54,099	49,498	78,466	78,466

Quarterly results – operations	Q1 '01	Q2 '01	Q3 '01	Q4 '01	Total	Q1 '00	Q2 '00	Q3 '00	Q4 '00	Total
Production, oil and liquids (Bbls/d)	6,416	6,167	6,261	6,754	6,400	3,024	3,930	5,273	4,946	4,298
Average price ($CDN/Bbl)	42.42	41.24	39.04	30.17	38.19	40.22	41.61	45.07	47.76	44.39
WTI $US/Bbl	28.69	27.97	26.50	20.43	25.95	28.72	28.63	31.55	31.84	30.26
Production, natural gas (Mmcf/d)	18.9	24.6	23.3	23.7	22.6	6.9	8.4	7.7	14.5	9.4
Average price ($CDN/Mcf)	11.04	6.66	2.74	2.97	5.57	2.90	4.07	5.21	12.21	7.26
Boe/d (10:1)	8,302	8,626	8,595	9,124	8,664	3,714	4,766	6,042	6,400	5,236
Boe/d (6:1)	9,560	10,266	10,151	10,705	10,173	4,175	5,323	6,556	7,370	5,862

The final quarter of 2001 was characterized by declining prices for crude oil and natural gas, driven by economic uncertainty and inventory oversupply. The average price received by the Company for crude oil fell before hedging gains to $30.17/Bbl in the fourth quarter from $39.04/Bbl in the third quarter of the year. Average gas prices rose to $2.97/Mcf from $2.74/Mcf in the third quarter of 2001. Comparable prices for the same quarter of the preceding year were $47.76/Bbl for crude oil and $12.21/Mcf for gas. Production on a Boe 6:1 basis for the quarter increased by 5% (10:1 - 6%) over the third quarter of 2001 and by 45% (10:1 - 43%) over the fourth quarter of 2000. Capital expenditures for the quarter rose to $18,632,000 from $13,047,000 in the third quarter of 2001 and from $17,763,000 (before acquisition costs of $30 million associated with the Tommy Lakes property) in the same quarter of 2000 as the Company began its winter drilling program.

LIQUIDITY AND CAPITAL

The Company's preliminary capital expenditure budget for 2002 anticipates the expenditure of $40.4 million which will be funded from cash flow which is budgeted to amount to approximately $78.2 million. Capital programs will thus amount to 52% of cash flow. Cash flow in excess of capital expenditures will be applied to reduce the Company's bank line, which by year end, assuming no additional capital programs are implemented, will be less than $30 million. The Company's current bank line amounts to $90 million. Accordingly, the Company has considerable financial resources available to pursue exploration or acquisition opportunities. Within working capital, receivables and payables are settled in accordance with normal industry standards. Given the recent collapse of Enron Corp and related concerns about debt downgrading at other marketing firms, the Company has taken steps to improve the quality of receivables from such organizations.

ACCOUNTING AND AUDIT

The Company's conservative approach to financing of its operations also extends to transaction and asset measurement. Accounting, financial measurement and reserve evaluation in the oil and gas industry are based on standards that are well established and have evolved over a period of time. These standards also have widespread acceptance, contributing to comparability between firms. There are certain aspects of the Company's operations and financial measurement which merit review in the light of recent concerns about the overall quality of accounting measurement across a range of industries. The Company conducts part of its operations through joint venture relationships with other industry partners. The financial terms of joint ventures vary widely but for accounting purposes the Company follows industry practice of including in its accounts only its pro rata share of income, costs, receivables, payables, obligations and capital expenditures from such joint ventures. With respect to financing of projects, generally joint ventures relating to producing wells are self-financed as production revenues are first applied against operating costs before the net amount is distributed to participants. With respect to exploration or development joint ventures, participants are subject to cash calls reflecting their economic interest in the project, which are used to fund project costs. The Company is not a party to any joint venture which has stand alone financing and does not guarantee the debt obligations of any third party. The Company also uses financial instruments such as hedges. With respect to hedge contracts, the Company marks to market and recognizes income and losses from contracts for only that part of the contract completed at period end. The Company does not include in income any gains from hedge contracts which relate to sales of oil or gas made subsequent to the end of the measurement period. Finally the Company is not a party, either directly or through guarantees, to any financial arrangements or obligations which may be regarded as off balance sheet.

The Company has employed the accounting firm of Deloitte & Touche LLP since the year ended December 31, 1999 to audit its annual financial statements and to review its quarterly reports before delivery to shareholders. Audit representatives meet with the Audit Committee of the Board of Directors prior to the release of quarterly and annual financial information. The Company also uses Deloitte & Touche LLP to provide tax services. The Company does not use Deloitte & Touche LLP to provide any other consulting services.

Audit and other fees ($ thousands)

Year ended December 31	2001	2000
Annual audit and review of quarterly reports	53.5	42.6
Tax services	51.8	10.5
Total	105.3	53.1

BUSINESS RISKS

Exploration and development

The Company faces intense competition for land, for experienced drilling crews and for capable technical staff. The Company addresses this risk by focusing on specific geographic areas where detailed knowledge can be successfully levered. In addition, the Company's preference for high working interests and field operatorship gives the Company superior control over the timing and quality of field projects. Staff compensation programs involve a stock option plan and a stock savings plan in which all staff are eligible to participate.

Processing

Oil and gas produced by the Company are processed at production facilities which can be subject to closure to accommodate scheduled and unscheduled maintenance or facility expansion. The Company mitigates this risk by taking an ownership position in key facilities.

Transportation

Products are usually transported to markets through a third party supplier and closures or curtailments may occur over which the Company has limited control.

Environmental

The Company's operations are environmentally sensitive and spills and other damage can occur for which the Company and its partners are liable for reclamation costs. The Company believes that it follows best oilfield practices in this area. Insurance is also maintained but the cost of such insurance is increasing and the coverage provided is decreasing.

Safety

Safety is a fundamental aspect of good oilfield practice. Appropriate training is provided to employees and the Company endeavours to secure experienced contractors and complies with industry standards and recommendations. The Company's chief operating officer reports to the Board of Directors at each meeting on safety and environmental compliance issues.

Kyoto Protocol

Canada is a signatory to the Kyoto Protocol regarding greenhouse gas emissions. At this stage timing of ratification of this agreement by the Canadian and United States governments is uncertain and public policy with respect to implementation of the agreement is equally uncertain. Accordingly, the Company is unable to measure the possible future impact of Kyoto on its business.

Land availability

Land otherwise available for exploration may become subject to endangered species protection legislation and First Nations traditional lands may be subject to restricted access. The Company actively participates with stakeholders in the resolution of land ownership and management issues.

Product prices

Product prices are volatile and are subject to a wide range of unforeseeable events outside of the Company's control. Risk can be mitigated by using hedges and other price protection mechanisms. The Company uses such tools to protect capital programs from payout delays and to secure suitably priced financing. The Company does not use hedging instruments to speculate on commodity price direction. Any hedging arrangements entered into by the Company require the approval of the president and the chief financial officer.

Foreign exchange

Ultimately the Company's products are priced in US dollars and the Canadian – US dollar exchange rate has a considerable impact on the Company's financial results. The Company may hedge this exposure, as part of its overall hedging strategy, however unhedged revenues have benefited from the steady erosion in value of the Canadian dollar in recent years.

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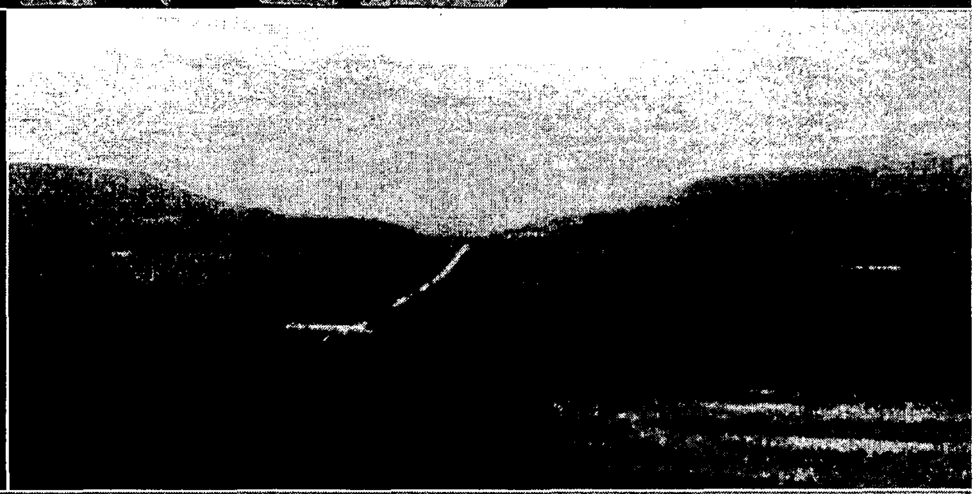
FINANCIAL REPORTS



MANAGEMENT'S REPORT

To the Shareholders of Storm Energy Inc.:

The financial statements of Storm Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgment, particularly in those circumstances where transactions affecting current periods are dependent on information not known for certain until a future period. The financial and operational information contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

(signed)

Donald McLean
Vice President, Finance and Chief Financial Officer
February 15, 2002

(signed)

Adeline Roth
Controller

AUDITORS' REPORT

To the Shareholders of Storm Energy Inc.:

We have audited the consolidated balance sheets of Storm Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed)

Calgary, Alberta
February 15, 2002

Deloitte & Touche LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31,	2001	2000
	$	$
ASSETS		
Current		
Accounts receivable	11,547,637	21,845,874
Prepaid expenses	1,327,909	1,831,522
	12,875,546	23,677,396
Capital assets [notes 2 & 3]	195,006,440	150,277,213
	207,881,986	173,954,609
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	23,856,894	30,380,452
Long term debt [note 4]	55,008,909	71,762,735
Provision for site restoration and abandonment	2,192,486	744,933
Future income tax [note 6]	35,768,729	12,677,527
SHAREHOLDERS' EQUITY		
Share capital [note 5]	39,378,878	38,653,624
Retained earnings	51,676,090	19,735,338
	91,054,968	58,388,962
	207,881,986	173,954,609

See accompanying notes

On behalf of the Board:

(signed)

Stuart G. Clark
Director

(signed)

Gregory G. Turnbu
Director

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

Years Ended December 31,	2001 $	2000 $
Revenue		
Production income	134,028,009	88,528,815
Royalties	(36,477,467)	(26,282,050)
Alberta royalty tax credit	572,626	296,173
Other income	1,332,345	1,140,854
	99,455,513	63,683,792
Expenses		
Production	14,412,026	9,111,334
General and administrative	2,710,762	1,875,585
Interest on long term debt	4,212,735	3,287,990
Depletion and depreciation [note 2]	21,022,066	12,961,244
Provision for site restoration and abandonment	1,451,555	662,801
	43,809,144	27,898,954
Income before income and other taxes	55,646,369	35,784,838
Income and other taxes [note 6]		
Future income tax	23,091,202	17,036,077
Current and large corporations tax	413,411	410,061
	23,504,613	17,446,138
Net income for the year	32,141,756	18,338,700
Retained earnings, beginning of year	19,735,338	2,445,277
Purchase cost in excess of stated value of shares redeemed [note 5]	(201,004)	(1,048,639)
Retained earnings, end of year	51,676,090	19,735,338
Net income per share [note 7]		
Basic	1.16	0.78
Diluted	1.13	0.77

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31,	2001 $	2000 $
Operating activities		
Net income for the year	32,141,756	18,338,700
Add non-cash items:		
Depletion and depreciation	21,022,066	12,961,244
Provision for site restoration and abandonment	1,451,555	662,801
Future income tax	23,091,202	17,036,077
Cash flow from operations	77,706,579	48,998,822
Site restoration paid	(3,996)	(8,201)
Net change in non-cash working capital items [note 8]	1,775,205	394,971
	79,477,788	49,385,592
Financing activities		
Proceeds from exercise of stock options	790,678	131,928
Proceeds from exercise of warrants	–	7,159,000
Common shares repurchased [note 5]	(266,428)	(1,394,937)
(Decrease) increase in long term debt	(16,753,826)	39,448,808
	(16,229,576)	45,344,799
Investing activities		
Capital asset additions	(67,159,963)	(105,814,157)
Capital asset dispositions	1,408,664	4,462,140
Net change in non-cash working capital items [note 8]	2,503,087	6,621,626
	(63,248,212)	(94,730,391)
Increase (decrease) in cash during the year	–	–
Cash, beginning of year	–	–
Cash, end of year	–	–
Cash flow from operations per share [note 7]		
Basic	2.81	2.08
Diluted	2.72	2.05

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2001 and 2000

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements include the accounts of Storm Energy Inc. ("the Company") and its subsidiary and have been prepared in accordance with Canadian generally accepted accounting principles. The preparation of these consolidated financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the amounts reported in the statements and the accompanying notes. Correspondingly, actual results could differ from estimated amounts. These consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Capital Assets

a. Petroleum and Natural Gas Properties and Equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre. Such costs include lease acquisition, drilling, geological and geophysical equipment costs and overhead expenses related to exploration and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the relative energy content of each product. Processing facilities are depreciated on a straight-line basis over the estimated useful life of the facility.

The depletion and depreciation cost base includes total capitalized costs, less prior depletion and depreciation charges, less costs of unproved properties, plus provision for future development costs of proved undeveloped reserves.

The net carrying value of the Company's petroleum and natural gas properties is limited to an ultimate recoverable amount ("ceiling test"). This amount is the aggregate of estimated future net revenues from proved reserves and the costs of unproved properties, net of impairment allowances, less future estimated production costs, general and administrative costs, financing costs, future removal and site restoration costs and income taxes. Future net revenues are estimated using prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at the end of the year.

b. Office Furniture and Equipment

Office furniture and equipment are recorded at cost and are depreciated on the declining balance basis using rates varying from 7% to 100%.

c. Leasehold Improvements

Leasehold improvements are recorded at cost and are depreciated on a straight-line basis over the lease term, including one renewal period.

d. Provision for Site Restoration and Abandonment

Provisions for future site restoration and abandonment are made over the life of the Company's oil and gas properties using a unit-of-production basis. The estimate includes the cost of equipment removal and environmental clean up in accordance with current cost, anticipated methods, existing legislation and industry practice. Actual expenditures are charged against the provision as incurred.

Joint Operations

Certain of the Company's exploration and production activities are conducted jointly with others through unincorporated joint ventures. The accounts of the Company reflect its proportionate interest in such activities.

Income Taxes

Income taxes are calculated using the liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities. Future income tax liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of capital assets, the provision for site restoration and abandonment costs and amounts used for ceiling test calculations are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. These estimates of reserves and related future cash flows, are subject to measurement uncertainty and the impact on the financial statements of changes in such estimates in future periods could be material.

Financial Instruments

The Company periodically utilizes financial instruments and commodity contracts to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. These contracts are used as hedges against product price changes and are not used for speculative purposes. Payments and receipts on these contracts are recognized in sales revenues at the time of sale of the related production.

Short term financial instruments, being accounts receivable and accounts payable, approximate their carrying values. The fair value of long term debt approximates its carrying value due to the floating interest rate and the revolving nature of the obligation.

Stock Based Compensation

The Company has a stock based compensation plan as described in Note 5. No compensation expense is recognized for this plan when stock options are issued to employees. Any consideration paid by employees or directors with respect to the exercise of stock options is credited to share capital.

Per Share Amounts

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

2. CAPITAL ASSETS

	December 31, 2001		December 31, 2000	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Petroleum and natural gas properties and equipment	256,800,518	62,170,779	191,215,100	41,281,386
Office furniture and equipment	747,606	417,717	613,877	298,273
Leasehold improvements	120,672	73,860	88,522	60,627
	257,668,796	62,662,356	191,917,499	41,640,286
Net book value	195,006,440		150,277,213	

Undeveloped property costs of $6,607,000 (2000 - $3,967,000) were excluded from the depletion base at December 31, 2001.

A ceiling test calculation as at December 31, 2001 indicated that the ultimate recoverable amount from proved reserves exceeded the net carrying value of the Company's petroleum and natural gas properties. The ceiling test is a cost recovery test and is not intended to result in an estimate of fair market value. The prices used in the ceiling test were based on year end prices at December 31, 2001 being $28.61 per barrel of crude oil, $3.70 per mcf for gas and $17.48 per barrel for natural gas liquids.

As at December 31, 2001, the Company's share of the estimated future site restoration and abandonment costs to be accrued over the life of the remaining proved reserves was $10,147,000.

3. BUSINESS ACQUISITIONS

Included in capital additions for the year ended December 31, 2000 are the following major acquisitions:

a. Acquisition of Interest in Red Earth Properties

Effective May 1, 2000, the Company acquired certain petroleum and natural gas properties in the Red Earth area of north central Alberta for a purchase price of $21.0 million. The acquisition of these properties was funded utilizing the Company's credit facility.

b. Acquisition of Tommy Lakes Property

Effective November 1, 2000, the Company acquired certain petroleum and natural gas properties in the Tommy Lakes area of north east British Columbia for a purchase price of $30.0 million. The acquisition of these properties was funded utilizing the Company's credit facility.

4. LONG TERM DEBT

The Company has a revolving term credit facility with a Canadian financial institution, which has been classified as long term because the facility is reviewed annually and will continue to revolve unless certain conditions are not met. If the conditions are not met and the revolving period ceases, the facility automatically becomes a three year term facility. The Company has $90 million (2000 - $80 million) available under this facility. Under the facility, loan advances bear interest, payable monthly, at the bank's prime rate. A floating charge demand debenture in the amount of $150,000,000 covering all of the assets of the Company and a general security agreement have been pledged as collateral. The average interest rate on the amount drawn during the year was 6.2% (2000 – 7.4%).

5. SHARE CAPITAL

a. Authorized

An unlimited number of voting common shares

An unlimited number of preferred shares

b. Issued

	Number of Shares	Consideration $
Common Shares		
Balance as at December 31, 1999	21,726,264	30,849,912
Issued upon exercise of stock options	262,470	131,928
Issued upon exercise of warrants	5,727,200	8,018,080
Purchased by normal course issuer bid	(245,600)	(346,296)
Balance as at December 31, 2000	27,470,334	38,653,624
Issued upon exercise of stock options	358,074	790,678
Purchased by normal course issuer bid	(46,400)	(65,424)
Balance as at December 31, 2001	27,782,008	39,378,878

c. Stock Based Compensation Plan

The Company has a stock option plan under which it may grant, at the Company's discretion, stock options to its directors, officers and employees for the purchase of common shares. Under the plan, 2,092,681 (2000 – 1,850,755) shares are reserved for issuance. The exercise price of each option equals the weighted average price of the five days prior to the date of grant and an option's maximum term is five years. The options vest at the end of the fourth year.

A summary of the status of the Company's stock option plan as of December 31, 2001 and 2000, and changes during the years ending on those dates is presented below:

	2001		2000	
	Shares (000's)	Weighted-Average Exercise Price ($)	Shares (000's)	Weighted-Average Exercise Price ($)
Outstanding at beginning of year	1,807	3.01	1,310	1.76
Granted	995	8.91	759	4.29
Exercised	(358)	2.21	(262)	0.50
Cancelled	(564)	8.60	–	–
Outstanding at end of year	1,880	4.52	1,807	3.01

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

Range of exercise Price ($)	Number Outstanding at 12/31/01	Weighted-Average Remaining Contractual Life	Weighted-Average Price ($)	Number Exercisable at at 12/31/01	Weighted-Average Exercise Price ($)	Weighted-Average Remaining Contractual Life
1.55 – 2.04	255,000	2.61 years	1.96	97,500	1.98	2.62 years
2.10 – 2.77	598,750	2.44 years	2.27	242,000	2.17	2.27 years
3.08 – 5.82	551,000	3.73 years	4.83	120,500	4.98	3.78 years
6.05 – 9.49	475,000	4.84 years	8.61	–	–	–
1.55 – 9.49	1,879,750	3.45 years	4.52	460,000	2.87	2.74 years

d. Normal Course Issuer Bid

Effective December 12, 2001, the Company renewed its normal course issuer bid process for a period of one year beginning December 20, 2001. The normal course issuer bid enables the Company to purchase up to 5% of its issued and outstanding common shares, or a total of 1,386,000 (2000 – 1,350,000) common shares. During 2001, the Company purchased a total of 46,400 (2000 – 245,600) common shares for a total cash consideration of $266,428 (2000 - $1,394,937). As the consideration paid was in excess of the stated value of the shares, the amount of the excess totaling $201,004 (2000 - $1,048,639) was charged to retained earnings.

6. FUTURE INCOME TAX

The Company uses the liability method of tax allocation to record future income taxes, whereby differences between the carrying amount and the tax basis of assets and liabilities are used to calculate future tax liabilities or assets.

The provision for future income taxes is different from the amount computed by applying the combined statutory Canadian Federal and Provincial tax rates to income for the year before income taxes. The differences are as follows:

	2001	2000
Statutory combined federal and provincial income tax rate	42.62%	44.62%
Expected income taxes	23,716,482	15,967,195
Add (deduct) the income tax effect of:		
Non-deductible Crown charges	12,605,642	9,794,633
Resource allowance	(11,757,854)	(8,608,575)
Alberta royalty tax credit	(244,053)	(132,152)
Resource allowance rate reduction	(407,854)	–
Reduction in provincial tax rate	(615,102)	–
Other	(206,059)	14,976
	23,091,202	17,036,077
Large corporations tax	413,411	410,061
	23,504,613	17,446,138

The components of the future tax liability at December 31, 2001 and 2000 are as follows:

	2001	2000
Property and equipment	(36,858,847)	(13,009,916)
Provision for site restoration and abandonment	934,438	332,389
Other	155,680	–
Net future income tax asset (liability)	(35,768,729)	(12,677,527)

7. PER SHARE AMOUNTS

Effective January 1, 2001, the Company retroactively adopted the new recommendations of the Canadian Institute of Chartered Accountants with respect to the computation, presentation and disclosure of net income and cash flow from operations per share. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

Prior year diluted net income per share and cash flow from operations per share have been restated for this change.

	2001	2000
Basic		
Net income per share	1.16	0.78
Cash flow from operations per share	2.81	2.08
Weighted average number of shares outstanding (thousands)	27,627	23,576
Diluted		
Net income per share	1.13	0.77
Cash flow from operations per share	2.72	2.05
Weighted average number of shares outstanding (thousands)	28,559	23,869

If the imputed earnings method had been used, the reported amounts would have been:

	2001	2000
Diluted		
Net income per share	1.10	0.68
Cash flow from operations per share	2.66	1.77
Weighted average number of shares outstanding (thousands)	29,200	29,063

The number of shares used to calculate diluted net income and cash flow from operations per share for the year ended December 31, 2001 included the weighted average number of shares outstanding of 27,627,205 (2000 – 23,575,535) plus 932,244 (2000 – 293,783) shares related to the dilutive effect of stock options.

The diluted net income and cash flow from operations per share discussed above did not include 82,738 (2000 – 84,494) of stock options, both on a weighted average basis, because the respective exercise prices exceeded the average market price of the common shares and the effect would be anti-dilutive.

8. CASH FLOW INFORMATION

	2001	2000
Accounts receivable	10,298,237	(15,854,583)
Prepaid expenses	503,613	(1,093,100)
Accounts payable and accrued liabilities	(6,523,558)	23,964,280
Change in non-cash working capital	4,278,292	7,016,597
These changes relate to the following activities:		
Operating activities	1,775,205	394,971
Investing activities	2,503,087	6,621,626
	4,278,292	7,016,597
Interest paid	4,212,735	3,287,990
Income taxes paid	–	–

9. FINANCIAL INSTRUMENTS

The Company is party to certain financial instruments, such as crude oil and natural gas contracts and foreign currency forward contracts. The Company enters into these contracts for hedging purposes only in order to protect its cash flow on future sales from the potential adverse impact of low oil and gas prices and fluctuations in the U.S.-Canadian dollar exchange rate. The contracts reduce the fluctuations in sales revenues by establishing fixed prices or a trading range on a portion of its oil and gas sales. The Company's production income was reduced by $560,000 (2000 - $5,852,000) from hedging activities.

Based on the exchange rate in effect at December 31, 2001, the Company would have recognized a loss of $955,500 (2000 – loss of $768,250) on the foreign exchange contract.

Contracts outstanding in respect of hedging transactions are as follows:

Exposure	Volume Hedged	Pricing	Term
Gas	9,000 Gigajoules/d	Floor @ $2.75/GJ	Apr 1, 2002 – Oct 31, 2002
	12,755 Gigajoules/d	Cap @ $5.15/GJ	Nov 1, 2002 – Mar 31, 2003
	7,000 MMBtu/d	Floor @ $US 3.50/MMBtu	
		Cap @ $US 5.10/MMBtu	Nov 1, 2001 – Oct 31, 2002
Oil	1,000 Bbls/d	$37.63/Bbl	Jan 1, 2002 – Dec 31, 2002
Foreign Exchange		$US/$Cdn Exchange @ $1.4724	$US 735,000/month Nov 1, 2001 – Oct 31, 2002

10. COMMITMENTS

The Company is committed to lease payments in respect of office premises as follows:

2002	$1,044,000
2003	$ 844,000
2004	$ 387,000
2005	$ 372,000

Matthew J. Brister
President & C.E.O.

Stuart G. Clark
Executive Director

Donald G. McLean
Vice President, Finance & C.F.O.

P. Grant Wierzba
Vice President, Operations & C.O.O.

Harry Ediger
Vice President, Land

Thomas N. Lindskog
Vice President, Exploration

Brian Lavergne
Vice President, Production

Eric Blakely
Exploration Manager

Adeline L. Roth
Controller

Matthew J. Brister
John A. Brussa
Stuart G. Clark
J. Keith Farries, Chairman
D. Keith MacDonald
Gregory G. Turnbull
P. Grant Wierzba

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Trading Symbol "SME"

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Calgary, Alberta

Deloitte & Touche LLP
Calgary, Alberta

C.I.B.C., Oil & Gas Group
Calgary, Alberta

Valiant Corporate Trust Company
Calgary, Alberta

API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
$CDN	Canadian dollar
GJ	Gigajoules
GJ/d	Gigajoules per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
Mbbls	Thousands of barrels
Mmbbls	Millions of barrels
Mmcfe/d	Millions of cubic feet equivalent per day
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mstb	Thousand stock tank barrels
Mw	Megawatt
Mw/hr	Megawatt per hour
NGL	Natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
TSE	Toronto Stock Exchange
WTI	West Texas Intermediate
$US	United States dollar
3D	three dimensional

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April 3, 2002

Alberta Securities Commission *(via SEDAR)*
British Columbia Securities Commission *(via SEDAR)*
Manitoba Securities Commission *(via SEDAR)*
Ontario Securities Commission *(via SEDAR)*
Quebec Securities Commission *(via SEDAR)*
The Toronto Stock Exchange *(via SEDAR)*

Dear Sirs:

Re: Storm Energy Inc.
Annual and Special Meeting of Shareholders
To Be Held on May 15, 2002

In our capacity as the Agent for Storm Energy Inc., we are pleased to enclose herewith our Affidavit of Mailing with respect to the annual meeting material which was mailed to the shareholders of Storm Energy Inc., on April 3, 2002.

We trust this is satisfactory.

Yours truly,

"Cheryl Dahlager"
Cheryl Dahlager
Senior Account Manager

c.c. Storm Energy Inc.
Attn: Ms. Adeline Roth

DECLARATION AS TO MAILING

PROVINCE	)	IN THE MATTER OF **STORM ENERGY INC.**
OF	)	("CORPORATION"), THE ANNUAL AND SPECIAL MEETING OF
ALBERTA	)	SHAREHOLDERS TO BE HELD **MAY 15, 2002.**

I, CHERYL DAHLAGER, OF THE CITY OF CALGARY IN THE PROVINCE OF ALBERTA, DO SOLEMNLY DECLARE AS FOLLOWS:

1. I AM AN EMPLOYEE OF VALIANT TRUST COMPANY AND AS SUCH, HAVE KNOWLEDGE OF THE MATTERS HEREINAFTER DECLARED.

2. ON APRIL 3, 2002, I CAUSED TO BE MAILED IN A FIRST CLASS PREPAID ENVELOPE ADDRESSED TO EACH OF THE PERSONS OR FIRMS WHO ON APRIL 1, 2002, **WERE THE REGISTERED HOLDERS OF COMMON SHARES OF THE CORPORATION;**

   (a) a copy of the NOTICE OF THE ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS marked EXHIBIT "A" and identified by me;

   (b) a copy of the MANAGEMENT INFORMATION CIRCULAR marked EXHIBIT "B" And identified by me;

   (c) a copy of the INSTRUMENT OF PROXY marked EXHIBIT "C" and identified by me;

   (d) a copy of the 2001 ANNUAL REPORT marked EXHIBIT "D" and identified by me;

   (e) a RETURN ENVELOPE marked EXHIBIT "E" and identified by me;

3. I FURTHER CONFIRM THAT COPIES OF EXHIBITS "A" THROUGH "E" AS NOTED IN ITEM 2 ABOVE, WERE SENT BY COURIER ON **APRIL 3, 2002 TO EACH INTERMEDIARY HOLDING COMMON SHARES OF THE CORPORATION WHO RESPONDED TO THE SEARCH PROCEDURES PURSUANT TO CANADIAN SECURITIES ADMINISTRATORS' NATIONAL POLICY STATEMENT NO. 41 REGARDING SHAREHOLDER COMMUNICATION.**

AND I MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH AND BY VIRTUE OF THE CANADA EVIDENCE ACT.

DECLARED BEFORE ME AT THE CITY OF
CALGARY IN THE PROVINCE OF ALBERTA
THIS 3RD DAY OF APRIL 2002.

"Pam Elliott"	"Cheryl Dahlager"
COMMISSIONER FOR OATHS IN AND FOR THE PROVINCE OF ALBERTA	Cheryl Dahlager

My commission expires on November 15, 2003.