TWIN BUTTE ENERGY LTD.

2013

ANNUAL REPORT

HIGHLIGHTS

	Three months ended December 31			Twelve months ended December 31		
	2013	2012	% Change	**2013**	2012	% Change
FINANCIAL *($000's, except per share amounts)*						
Petroleum and natural gas sales	**106,849**	88,673	20%	**394,588**	304,729	29%
Funds flow (1)	**36,978**	37,754	-2%	**137,358**	136,034	1%
Per share basic	**0.12**	0.16	-25%	**0.52**	0.67	-22%
Per share diluted	**0.12**	0.16	-25%	**0.52**	0.66	-21%
Net income (loss)	**(88,028)**	(5,381)	-1536%	**(115,633)**	31,530	-467%
Per share basic	**(0.28)**	(0.02)	-1300%	**(0.44)**	0.15	-393%
Per share diluted	**(0.28)**	(0.02)	-1300%	**(0.44)**	0.15	-393%
Dividends declared	**15,577**	10,579	47%	**52,286**	37,249	40%
Dividends declared, Post DRIP	**14,208**	9,443	50%	**46,883**	35,573	32%
Capital expenditures (2)	**33,632**	38,530	-13%	**77,176**	87,742	-12%
Corporate acquisitions (2)	**356,521**	134,972	164%	**356,521**	428,392	-17%
Net debt (3)	**361,612**	201,703	79%	**361,612**	201,703	79%
OPERATING						
Average daily production						
Heavy crude oil (bbl per day)	**13,123**	14,450	-9%	**13,630**	11,343	20%
Light & Medium crude oil (bbl per day)	**4,710**	672	601%	**1,659**	742	124%
Natural gas (Mcf per day)	**11,634**	13,174	-12%	**12,572**	14,009	-10%
Natural gas liquids (bbl per day)	**188**	213	-12%	**201**	261	-23%
Barrels of oil equivalent (boe per day, 6:1)	**19,960**	17,531	14%	**17,585**	14,681	20%
% Oil and NGLs	**90%**	87%	3%	**88%**	84%	5%
Average sales price						
Heavy crude oil ($ per bbl)	**60.28**	58.88	2%	**66.33**	63.19	5%
Light & Medium crude oil ($ per bbl)	**66.19**	75.14	-12%	**70.73**	78.50	-10%
Natural gas ($ per Mcf)	**3.78**	3.52	7%	**3.47**	2.57	35%
Natural gas liquids ($ per bbl)	**77.50**	76.01	2%	**80.02**	82.74	-3%
Barrels of oil equivalent ($ per boe, 6:1)	**58.19**	54.98	6%	**61.47**	56.71	8%
Operating netback ($ per boe) (4)						
Petroleum and natural gas sales	**58.19**	54.98	6%	**61.47**	56.71	8%
Cash (loss) gain on derivative instruments	**1.41**	4.83	-71%	**0.60**	5.47	-89%
Royalties	**(11.50)**	(9.83)	-17%	**(12.78)**	(11.97)	-7%
Operating expenses	**(21.12)**	(19.73)	-7%	**(21.83)**	(18.55)	-18%
Transportation expenses	**(2.06)**	(2.82)	27%	**(2.44)**	(2.52)	3%
Operating netback	**24.92**	27.43	-9%	**25.02**	29.14	-14%
Wells drilled						
Gross	**26.0**	23.0	13%	**97.0**	95.0	2%
Net	**24.3**	23.0	6%	**95.3**	77.2	23%
Success (%)	**96**	87	10%	**93**	95	-2%
COMMON SHARES						
Shares outstanding, end of period	**343,079,562**	248,311,634	38%	**343,079,562**	248,311,634	38%
Weighted average shares outstanding – diluted	**309,082,232**	239,331,527	29%	**265,191,273**	205,581,356	29%

(1) Funds flow from operations and funds flow from operating netback are non-GAAP measures that represent the total and the average per boe, respectively, of cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

(2) Corporate acquisitions is a non-GAAP measure and includes total consideration plus working capital deficiency acquired in a corporate acquisition. Capital expenditures is a non-GAAP measure calculated as the purchase or sale price of an asset, plus development capital expenditures added to PP&E. Corporate acquisitions are excluded from this measure.

(3) Net debt is a non-GAAP measure representing the total of bank indebtedness, accounts payables and accrued liabilities, cash dividend payable, less accounts receivables, deposits and prepaids.

(4) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales plus realized gains on derivatives, less royalties, operating and transportation expenses.

REPORT TO SHAREHOLDERS

HIGHLIGHTS OF TWIN BUTTE'S SUCCESSFUL 2013 ARE AS FOLLOWS:

- Closed the corporate acquisition of Black Shire on November 5, adding approximately 7,000 boe per day of production weighted 93% to medium gravity oil that improves corporate netbacks while reducing corporate decline rates.
- Completed an organic capital program of $106.4 million ($77.2 million net of dispositions) including the drilling of 97 gross (95.3 net) wells at a 93% success rate.
- Increased average annual production by 20% to 17,585 boe/d while increasing the oil & liquids weighting to 88% from 84%.
- Reinforced the sustainability of the dividend model by holding total payout to 94% (90% net of DRIP/SDP).
- Increased proven plus probable reserves by 21% to 68.2 MMboe from 56.2 MMboe in previous year.
- Generated total proved plus probable organic drilling finding and development ("F&D") costs of $21.39 per boe including changes in future development costs, before revisions, representing a 1.6 times recycle ratio based on estimated 2014 operating netbacks of $34.30 per boe.

CORPORATE

As highlighted by the Company's year end financial and operational results, during 2013, Twin Butte progressed and strengthened the Company's business model of delivering a long term stable dividend with moderate production growth. Strong financial discipline combined with a focused and successful capital plan ensured the Company maintained its monthly dividend while not overleveraging the Company's balance sheet and maintaining an all-in payout ratio of 90%. The fourth quarter acquisition of Black Shire significantly strengthened Twin Butte by adding a new core operating area in Provost with financial and performance attributes which augment and enhance the performance of the Company's historic heavy oil assets. The acquisition significantly improved Twin Butte's corporate sustainability by increasing its corporate netback, decreasing its corporate decline rate while adding a sizeable drilling inventory with capital efficiencies comparable to Twin Butte's existing heavy oil drilling inventory.

Twin Butte's strategic shift in 2013 to more horizontal drilling activity versus vertical delivered positive results by year end. The Company anticipates that this strategic shift will continue in 2014 with a 75% to 80% drilling weighting to horizontal activity planned.

FINANCIAL

Twin Butte's full year 2013 financial and operating results demonstrate the Company's ability to pay a sustainable dividend and maintain a strong balance sheet while completing a disciplined capital plan. The Company paid $52.3 million in dividends ($46.9 million post DRIP) in 2013 which when combined with net $77.2 million in organic capital spending generated an all-in payout ratio of 90%, consistent with 2012. In the fourth quarter, the Company completed the Black Shire acquisition for total proceeds of $356.5 million consisting of cash, assumed debt and the issuance of Twin Butte shares to Black Shire shareholders. A portion of the cash for the transaction was financed with a $70 million equity issue at $1.95 per share. The Company subsequently issued $85 million principal amount of 6.25% convertible unsecured subordinated debentures due December 31, 2018. At year end, Company net debt, including the debentures, was approximately $362 million, and the Company had $252.2 million drawn on its credit facility of $400 million.

During 2013, the Company continued its successful program of non-core asset dispositions, completing seven separate transactions for gross proceeds of $29.6 million. These dispositions further focused the Company's asset base with proceeds being used to partially fund the Company's ongoing organic capital plans in its core operating areas in Lloydminster and Provost.

Funds flow for 2013 increased slightly from 2012 reaching $137 million. This figure is expected to increase to over $210 million in 2014 as a result of a full year of the higher netback production from the Provost area. Funds flow for the first quarter of 2014 is estimated to be $46-47 million.

Being primarily a heavy oil producer, the Company was not immune to the volatility of differentials from WTI to the WCS Canadian heavy oil index through 2013. Industry concerns with respect to potential transportation restrictions and refinery capacity for heavy oil barrels translated into a WCS price varying from a high in August of $94.66 per barrel to a low in February of $58.96 per barrel. Although differentials have significantly contracted in early 2014, Twin Butte anticipates continued volatility over the remainder of the year but longer term believes a WCS price in excess of $80 per barrel is reasonable. The Company's proactive hedging or risk management strategy stabilized realized pricing ensuring consistency of cash flow for the dividend and capital plan. For 2014, the Company is well positioned with approximately 47% of its anticipated heavy oil production hedged at approximately $75.00 per bbl. The Company has commenced layering in hedges for 2015 at WTI prices of close to $100 per barrel and WCS prices of approximately $77.00 per bbl.

The Black Shire acquisition has improved the Company's dividend sustainability since the Provost area's production is medium quality oil which, along with lower operating and royalty costs, will generate an operating netback premium of between $15 to 20 per barrel above the Company's Lloydminster heavy oil barrels.

OPERATIONS

The Company's 2013 capital plan was focused in its core heavy oil area at Lloydminster with the exception of two wells drilled in December on the acquired Provost assets. The $106.4 million of gross capital ($77.2 million net of dispositions) capital program included the drilling of 97 gross wells (95.3 net) of which 42% were horizontal. Strategically, this is up significantly from 2012 when only 3% of the Company's drilling was horizontal. 2014 will see the continued the shift to more horizontal drilling with 75% of the Company's wells anticipated to be horizontal. This is part of the ongoing transition of the Company to a more predictable and more sustainable base production profile.

Twin Butte's most active drilling area in 2013 was a horizontal heavy oil development in Wildmere, Alberta. The Wildmere asset was acquired in Q4 2012 and subsequently 30 horizontal wells were drilled on the property in 2013. Successful step-out wells drilled on the property in late 2013 and early 2014 have delineated an additional 20 horizontal locations which will be pursued in 2014.

Frog Lake had four horizontal wells drilled in 2013, following up on a successful horizontal drill in 2011. These wells should lead to additional horizontal drilling later in 2014 and onwards.

The Swimming property had nine wells drilled in 2013, comprised of eight vertical and one horizontal. Additional drilling at this property is planned for 2014.

Twin Butte's most active Saskatchewan drilling program was at Celtic where seven vertical wells were drilled in 2013. This area will see continued activity in 2014 to follow-up on significant 2013 new pool discoveries.

At Provost, a development horizontal drilling program commenced with two wells in 2013 followed by 15 wells in the first quarter of 2014. Based on the high productivity and high oil cuts on the drilled wells completed to date, the Company anticipates drilling a minimum of 45 wells in 2014 at Provost. Two new oil and water handling facilities commissioned at Provost late in the fourth quarter and early in the first quarter, along with the Company's other extensive infrastructure, will enable the new wells to be brought on stream promptly throughout the year.

2013 production averaged 17,585 boe/d which was up 20% from the 2012 average of 14,681 boe/d. Fourth quarter 2013 production hit a new corporate high, averaging 19,960 boe/d primarily due to the Black Shire acquisition which was effective November 5th.

Production for the first quarter of 2014 is anticipated to be approximately 22,500 boe/d. This rate is slightly lower than Twin Butte's year end 2013 exit rate as difficult weather related operating conditions were experienced during January and February. Current production is approximately 23,000 boe/d.

Year to date, the Company has drilled 34 gross (34 net) wells, including 18 horizontal wells of which 15 were in the Provost area. The Company has prepared for breakup by positioning three drilling rigs on pads to drill 12 wells during the first six weeks of Q2. These wells will be completed and tied-in after break-up when field conditions permit.

RESERVES

In 2013, Twin Butte continued to grow corporate reserves through its organic capital plan (drilling) and the strategic acquisition of Black Shire. Year-end proved and proved and probable reserves were up 22% and 21% respectively, from year end 2012 levels. With 100% of the Company's 2013 capital activity directed towards oil, the liquid reserve weighting grew to 80% from 73% in 2012.

For reconciliation purposes, the 2013 capital plan was broken down as to \$106.4 million, \$29.2 million and \$356.5 million, respectively, for the drilling, disposition and acquisition program. The tables below show additions by each commodity and reserve classification. The Company's organic drilling program added 6.1 MMboes of reserves whereas acquisitions added 18.0 MMboes of reserves partially offset by 2.9 MMboes of reserve dispositions. Changes or negative revisions to the year end 2012 reserve estimate were 2.7 MMboes or 4.8% of the year end 2012 reserves. These changes were primarily in the probable category as Twin Butte experienced positive revisions on a proved basis for the second year in a row. Proved producing reserves booked at year end 2012 also experienced positive revisions. Approximately 20% of this revision was in natural gas where Twin Butte has not directed any capital for the past three years. Earlier reported performance issues at the Company's Primate property in western Saskatchewan accounted for an additional 20% of the negative revisions. The Company's move to a greater percentage of its drilling activity being horizontally based is a direct reflection of the target sizes and average booked reserve per vertical well getting smaller. Overall, the organic program generated a very reasonable finding and development cost of \$21.29 per boe including changes in forward development capital, however, incorporating the negative revisions, this figure increased to \$38.46 per boe.

The acquisition component of Twin Butte's 2013 capital plan was dominated by the Black Shire acquisition which added approximately 18 MMboes of reserves. These reserves were added at a very attractive price of \$23.93 per boe including forward capital but excluding any value for undeveloped land which the Company anticipates will generate a forward recycle ratio of close to 2.0 times.

All-in finding development, acquisition and disposition costs, including changes in forward development capital was \$24.22 per boe before revisions and \$27.76 per boe including revisions. At year end 2013, the Company had 385,000 net acres of undeveloped and non-producing acreage which was independently valued at year end at \$83 million.

The Company's reserves data set forth below is based on an evaluation and review completed by the independent reserve engineering firm, McDaniel & Associates Consultants Ltd ("McDaniel"), with an effective date of December 31, 2013. McDaniel evaluated approximately 74% (90% of total proved plus probable future net revenue discounted at 10%) of Twin Butte's assigned total proved plus probable reserves and reviewed the internal evaluation completed by Twin Butte on the remaining portion, which primarily included certain non-core natural gas properties. McDaniel's evaluation and review was prepared in accordance with standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and the COGEH.

SUMMARY OF TOTAL COMPANY RESERVES

	Forecast Prices and Costs					
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserve Category	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)
Proved						
Developed Producing	2,656.1	2,471.9	14,254.3	12,353.4	1,788.6	1,209.5
Developed Non-Producing	47.7	44.7	1,862.8	1,585.0	392.9	264.8
Undeveloped	485.3	420.0	7,634.0	6,615.0	336.2	235.3
Total Proved	3,189.1	2,936.5	23,751.1	20,553.5	2,517.7	1,709.7
Probable	1,840.4	1,622.8	22,642.3	19,146.2	949.9	653.3
Total Proved Plus Probable	**5,029.5**	**4,559.3**	**46,393.4**	**39,699.7**	**3,467.6**	**2,363.0**
Total Proved Plus Probable						
Developed Producing	3,585.8	3,323.4	19,898.5	17,083.6	2,163.9	1,465.9

Reserve Category	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent [3]	
	Gross [1] (MMcf)	Net [2] (MMcf)	Gross [1] (Mboe)	Net [2] (Mboe)
Proved				
Developed Producing	41,310.8	34,510.7	25,584.1	21,786.6
Developed Non-Producing	7,086.1	5,733.8	3,484.4	2,850.2
Undeveloped	6,996.4	5,871.6	9,621.6	8,248.9
Total Proved	55,393.4	46,116.1	38,690.1	32,885.8
Probable	24,623.2	20,209.7	29,536.5	24,790.5
Total Proved Plus Probable	**80,016.6**	**66,325.8**	**68,226.7**	**57,676.3**
Total Proved Plus Probable				
Developed Producing	51,372.2	42,864.7	34,210.3	29,017.0

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Twin Butte before deductions of royalties payable to others.

(2) "Net" reserves means Twin Butte gross reserves less all royalties payable to others.

(3) "Oil Equivalent" amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 Mcf: 1 bbl may be a misleading indication of value.

(4) Numbers in tables may not add due to rounding.

Summary of Net Present Value of Future Net Revenue [1]

As at December 31, 2013

Before Income Taxes and Discounted at (%/year)

Reserve Category	0% *($000s)*	5% *($000s)*	10% *($000s)*	15% *($000s)*
Proved				
Developed Producing	616,509.6	535,769.0	480,101.3	438,884.4
Developed Non-Producing	88,405.7	62,623.2	50,690.0	43,254.1
Undeveloped	191,329.2	152,155.2	123,598.1	101,858.6
Total Proved	896,244.4	750,547.4	654,389.3	583,997.1
Probable	832,023.4	615,459.6	488,464.8	401,541.1
Total Proved Plus Probable	**1,728,267.8**	**1,366,007.0**	**1,142,854.1**	**985,538.2**
Total Proved Plus Probable				
Developed Producing	884,396.9	726,929.5	632,141.0	566,466.8

(1) Based on McDaniel forecast prices and costs

Reserve Reconciliation

Reconciliation of Gross Company Interest Reserves (1) (2) (4)
By Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Oil		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2012	1,232.5	733.9	1,966.4	17,525.0	17,830.5	35,355.5
Discoveries, Extensions and Improved Recoveries	93.8	60.3	154.1	4,123.5	1,651.8	5,775.3
Technical Revisions	283.4	112.8	396.2	64.5	(2,714.9)	(2,650.4)
Acquisition(5) and Dispositions	1,793.1	933.5	2,726.6	7,405.4	5,875.0	13,280.4
Production	(213.7)	0.0	(213.7)	(5,367.3)	0.0	(5,367.3)
December 31, 2013	**3,189.1**	**1,840.4**	**5,029.5**	**23,751.1**	**22,642.3**	**46,393.4**

	Natural Gas Liquids			Natural Gas Including Solution Gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
December 31, 2012	2,561.1	1,047.1	3,608.2	62,140.2	29,431.0	91,571.2
Discoveries, Extensions and Improved Recoveries	4	2	6	757.8	158.9	916.7
Technical Revisions	112.9	(49.2)	63.7	(426.7)	(2,640.5)	(3,067.2)
Acquisitions and Dispositions	(87.3)	(50.0)	(137.3)	(2,489.1)	(2,326.0)	(4,815.1)
Production	(73.0)	0.0	(73.0)	(4,589.0)	0.0	(4,589.0)
December 31, 2013	**2,517.7**	**949.9**	**3,467.6**	**55,393.4**	**24,623.2**	**80,016.6**

	Oil Equivalent (3)		
	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2012	31,675.2	24,516.6	56,191.8
Discoveries, Extensions and Improved Recoveries	4,347.6	1,740.6	6,088.2
Technical Revisions	390.1	(3,091.9)	(2,701.8)
Acquisitions and Dispositions	8,696.2	6,371.3	15,067.5
Production	(6,419.0)	0.0	(6,419.0)
December 31, 2013	**38,690.1**	**29,536.5**	**68,226.6**

(1) Gross Company interest reserves include solution gas but do not include royalties.

(2) Reserve information as at December 31, 2012 and 2013 is prepared in accordance with NI 51-101.

(3) Oil equivalent amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 Mcf: 1 bbl may be a misleading indication of value.

(4) Numbers in tables may not add due to rounding.

(5) The reserve volumes attributed to the acquisitions are the Company's best estimate at the effective date based on the December 31, 2012 independent reserve evaluation for the assets less production.

Capital Expenditures (1)

Type	2013 Capital Expenditures $(000's)
Land	3,766
Seismic	2,420
Drilling & Completions	65,234
Equipping & Facilities	31,538
G&A and Other	3,479
Total Development Costs	106,437
Acquisition – Black Shire	356,521
Dispositions net	(29,261)
Total A&D	327,260
Total Capital	**433,697**

(1) Capital expenditures is a non-GAAP measure calculated as the purchase or sale price of an asset, plus development capital expenditures added to PP&E.

Capital Program Efficiency

	2013
Excluding Future Development Costs	
FD&A cost – Proved ($/boe)	
Additions and revisions (1)	22.47
Acquisitions & Dispositions	37.63
Total	32.28
FD&A costs – Proved plus probable ($/boe)	
Additions and revisions (1)	31.43
Acquisitions & Dispositions	21.72
Total	**23.50**
Forecast 2014 operating netback per boe (2)	34.30
Recycle ratio (2)	
Proved plus probable	1.5
Including Changes in Future Development Costs	
FD&A costs – Proved ($/boe) (3)	
Additions and revisions (1)	24.59
Acquisitions & Dispositions	41.51
Total	35.54
FD&A costs – Proved plus probable ($/boe) (3)	
Additions and revisions (1)	38.46
Acquisitions & Dispositions	25.36
Total	**27.76**
Forecast 2014 operating netback per boe (2)(3)	34.30
Recycle ratio (2)	
Proved plus probable	1.2

(1) The aggregate of the additions and revisions costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, production and operating expenses and transportation expenses.

(3) Oil equivalent amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 Mcf: 1 bbl may be a misleading indication of value.

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to proved producing status. For continuity, Twin Butte has presented FD&A costs calculated excluding and including changes in FDC. Changes in forecast FDC occur annually as a result of development, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production.

Reserve Life Index

The following table sets forth Twin Butte's reserve life index based on total proved and proved plus probable reserves and estimated average first quarter 2014 production of 22,500 boe/d.

	Reserve Life Index (years)		
	Production	Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	20,400	4.0	7.4
Natural Gas (mcf/d)	12,600	12.0	17.4
Oil Equivalent (boe/d)	22,500	4.7	8.3

Future Development Costs (Undiscounted)

Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2014	57,900	111,600
2015	57,200	112,700
2016	41,000	91,400
2017	7,900	16,700
2018	1,300	700
Remaining	1,900	7,300
Total (Undiscounted)	**167,200**	**340,400**

Net Asset Value

The following net asset value ("NAV") table shows a NAV calculation under which the Company's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions, including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV per share represents the fair market value of Twin Butte shares. The calculations below do not reflect the value of the Company's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment.

Using Twin Butte's Reserve Value at December 31, 20123 – Forecast Pricing and Costs (Pre tax)

($MM except as noted)	5%	10%
Proved plus Probable Reserve Value	1,366.0	1,142.9
Undeveloped Land Value (1)	83.3	83.3
Net Debt (2)	(361.6)	(361.6)
Option Proceeds	1.7	1.7
Basic Shares Outstanding (MM)	343.1	343.1
Estimated Net Asset Value $ per Share - Basic	**3.17**	**$2.52**
Fully Diluted Shares Outstanding (MM)	349.1	349.1
Estimated Net Asset Value $ per Share – Fully Diluted	**3.12**	**$2.48**

(1) Independent assessment of 385,367 net undeveloped acres at an average price of $216/acre.

(2) Net debt is a non-GAAP measure representing the total of bank indebtedness, accounts payable and accrued liabilities, cash dividend payable, less accounts receivables, deposits and prepaids.

OUTLOOK

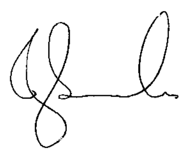
Twin Butte has continued to execute on its strategy of delivering moderate growth while paying a sustainable dividend. With year-end 2013 debt of approximately $361.6 million and anticipated 2014 cash flow in excess of $210 million, the Company is well financed to pay its annual dividend and complete its forecast 2014 capital plan of $145 million while maintaining an all-in payout ratio of under 100%. The recent move into Provost has strengthened and enhanced the Company's dividend sustainability and provided a platform for longer term moderate growth. Heavy oil at Lloydminster has and will remain a core focus for the Company, however, with enhanced netbacks and recycle rates at Provost, more capital will be directed to these assets.

The Company will continue to match its capital plan to forecast cash flow less dividends. Recent positive movement in both oil pricing and the light to heavy oil differentials, combined with the Company's strong hedge position, allows Twin Butte to remain confident in the long term sustainability of the dividend and supports a possible expansion of the 2014 capital plan.

While remaining strongly positioned with its low risk drilling inventory, the Company continues to review acquisition opportunities to further diversify and enhance the Company's commodity and play type risk.

ABOUT TWIN BUTTE

Twin Butte Energy Ltd. is a dividend paying value oriented intermediate producer with a significant low risk, high rate of return drilling inventory focused on large original oil and gas in place play types. With a stable low decline production base, Twin Butte is well positioned to provide shareholders with a sustainable dividend with growth potential over both the short and long term. Twin Butte is committed to continually enhance its asset quality while focusing on the sustainability of its dividend. The common shares of Twin Butte are listed on the TSX under the symbol "TBE".



Jim Saunders
Chief Executive Officer

March 20, 2014

READER ADVISORY

Forward-Looking Statements

In the interest of providing Twin Butte's shareholders and potential investors with information regarding Twin Butte, including management's assessment of the future plans and operations of Twin Butte, certain statements contained in this annual report constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular but without limiting the foregoing, this annual report contains forward-looking statements pertaining to the following: the amount of horizontal drilling activity planned for 2014; future dividend levels; funds flow and cash flow forecasts; the volumes and estimated value of Twin Butte's oil and natural gas reserves; the life of Twin Butte's reserves; the volume and product mix of Twin Butte's oil and natural gas production; future oil and natural gas prices; future operational activities; future results from operations and operating metrics, including future production growth and other matters set forth under the heading "Outlook" herein, including estimated budget levels and targeted pay-out ratio in respect of the payment of dividends. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

With respect to forward-looking statements contained in this annual report, Twin Butte has made assumptions regarding, among other things: future capital expenditure levels; future oil and natural gas prices and differentials between light, medium and heavy oil prices; results from operations including future oil and natural gas production levels; future exchange rates and interest rates; Twin Butte's ability to obtain equipment in a timely manner to carry out development activities; decline rates based on analogous information; its ability to market its oil and natural gas successfully to current and new customers; the impact of increasing competition; Twin Butte's ability to obtain financing on acceptable terms; and Twin Butte's ability to add production and reserves through its development and exploitation activities. Although Twin Butte believes that the expectations reflected in the forward looking statements contained in this annual report, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this annual report, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Twin Butte's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the following: the risks associated with the oil and gas industry; commodity prices; operational risks in exploration; development and production; delays or changes in plans; risks associated with the uncertainty of reserve estimates; health and safety risks, and; the uncertainty of estimates and projections of production, costs and expenses. volatility in market prices for oil and natural gas; general economic conditions in Canada, the U.S. and globally; and the other factors described under "Risk Factors" in Twin Butte's most recently filed Annual Information Form available in Canada at www.sedar.com. The recovery and reserve estimates of Twin Butte's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this annual report speak only as of the date of this annual report. Except as expressly required by applicable securities laws, Twin Butte does not undertake any obligation to publicly update or revise any forward looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this annual report are expressly qualified by this cautionary statement.

Barrels of Oil Equivalent

Barrels of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indicated value.

Reserve Life Index

The reader is also cautioned that this annual report contains the term reserve life index ("RLI"), which is not a recognized measure under generally accepted accounting principles ("GAAP"). Management believes that this measure is a useful supplemental measure of the length of time the reserves would be produced over at the rate used in the calculation. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms determined in accordance with GAAP as a measure of performance. Twin Butte's method of calculating this measure may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

Operating Netback

The reader is also cautioned that this annual report contains the term operating netback, which is not a recognized measure under GAAP and is calculated as a period's sales of petroleum and natural gas, net of royalties less net production and operating expenses as divided by the period's sales volumes. Management uses this measure to assist them in understanding Twin Butte's profitability relative to current commodity prices and it provides an analysis tool to benchmark changes in operational performance against prior periods and to peers on a comparable basis. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with GAAP as a measure of performance. Twin Butte's method of calculating this measure may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

Net Debt

The reader is cautioned that this annual report contains the term net debt, which is not a recognized measure under GAAP and is calculated as bank debt adjusted for working capital excluding mark-to-market derivative contracts. Working capital excluding mark-to-market derivative contracts is calculated as current assets less current liabilities both of which exclude derivative contracts and current liabilities excludes the current portion of debt. Management uses net debt to assist them in understanding Twin Butte's liquidity at specific points in time. Mark-to-market derivative contracts are excluded from working capital, in addition to net debt, as management intends to hold each contract through to maturity of the contract's term as opposed to liquidating each contract's fair value or less.

Future Oriented Financial Information

This annual report, in particular the information in respect of anticipated cash flows, may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by management of the Company to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. The Company and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as of March 20, 2014

INTRODUCTION

The following Management Discussion and Analysis ("MD&A") is management's assessment of Twin Butte Energy Ltd.'s ("Twin Butte" or the "Company") financial and operating results and should be read in conjunction with the message to shareholders and the audited financial statements of the Company for the year ended December 31, 2013 and the audited financial statements and MD&A for the year ended December 31, 2012. This MD&A is presented in Canadian dollars (except where otherwise noted). Additional information relating to the Company, including the Company's Annual Information Form can be found on www.sedar.com.

The Company's principal activity is the acquisition of, exploration for and the development and production of petroleum and natural gas properties in Western Canada.

Non-GAAP Measures – Certain measures in this document do not have a standardized meaning as prescribed by IFRS, such as operating netback, funds flow from operations, funds flow per share, payout ratio, total payout ratio, and net debt and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. The term funds flow from operations or funds flow should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

Basis of Presentation – The reporting and measurement currency is the Canadian dollar.

boe Presentation – Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion rate of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the report are derived by converting gas to oil equivalent barrels at the ratio of six thousand cubic feet of gas to one barrel of oil.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A constitute forward-looking information within the meaning of securities laws. Forward-looking information may relate to our future outlook and anticipated events or results and may include statements regarding the future financial position, business strategy, budgets, projected costs, capital expenditures, financial results, taxes and plans and objectives of or involving Twin Butte. Particularly, statements regarding our future operating results and economic performance are forward-looking statements. In some cases, forward-looking information can be identified by terms such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "intend", "estimate", "predict", "potential", "continue" or other similar expressions concerning matters that are not historical facts.

These statements are based on certain factors and assumptions regarding expected growth, results of operations, performance and business prospects and opportunities. While we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Forward looking-information is also subject to certain factors, including risks and uncertainties that could cause actual results to differ materially from what we currently expect. These factors include risk associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risk, and competition from other producers and ability to access sufficient capital from internal and external resources.

Other than as required under securities laws, we do not undertake to update this information at any particular time.

All statements, other than statements of historical fact, which address activities, events, or developments that Twin Butte expects or anticipates will or may occur in the future, are forward-looking statements within the meaning of applicable securities laws. These statements are subject to certain risks and uncertainties, and may be based on estimates or assumptions that could cause actual results to differ materially from those anticipated or implied.

Further, the forward-looking statements contained in this MD&A are made as of the date hereof, and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, as a result of new information, future events or otherwise, except as may be required by applicable securities laws. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. Certain risk factors associated with these forward-looking statements include, but are not limited to, the following:

- Fluctuations in natural gas, condensate, NGL's, and crude oil production levels;
- Twin Butte's inability to successfully market its natural gas, condensate, NGL's, and crude oil;
- Lower than expected market prices for natural gas, condensate, NGL's, and crude oil;
- Adverse changes in foreign currency exchange rates and/or interest rates;
- Uncertainties associated with estimating reserves;
- Competition for capital, asset acquisitions, undeveloped lands, and skilled personnel;
- Operational hazards characteristic of the oil and gas industry such as: geological and drilling problems; and well production, pipeline, and mechanical difficulties;
- Lower than envisaged success in the finding and development of reserves and/or higher than expected costs;
- Adverse changes in general economic conditions in Western Canada, Canada more generally, North America or globally;
- Adverse weather conditions;
- The inability of Twin Butte to obtain financing on favorable terms, or at all;
- Adverse impacts from the actions of competitors;
- Adverse impacts of actions taken and/or policies established by governments or regulatory authorities including changes to tax laws, incentive programs, royalty calculations, and environmental laws and regulations; and
- Reliance on natural gas and NGL processing, pipeline, and storage infrastructure not operated by Twin Butte, the availability of which is essential to Twin Butte's sales and marketing activities.

Additional information relating to Twin Butte, including Twin Butte's financial statements can be found on SEDAR at www.sedar.com or the Company's website at www.twinbutteenergy.com.

2013 OVERVIEW

Twin Butte experienced significant growth in 2013, through development drilling and with the corporate acquisition of Black Shire Energy Inc. ("Black Shire") on November 5, 2013. This acquisition translated into increased medium oil production, cash flow and capital spending in the fourth quarter of 2013.

PETROLEUM AND NATURAL GAS SALES

Twin Butte realized the following sales, production volumes, and commodity prices:

	Three months ended December 31		Twelve months ended December 31	
	2013	2012	**2013**	2012
Sales *($000's)*				
Heavy oil	**72,781**	78,268	**329,966**	262,316
Light & Medium oil	**28,678**	4,650	**42,842**	21,338
Natural gas	**4,045**	4,263	**15,531**	13,178
Natural gas liquids	**1,345**	1,492	**6,249**	7,897
Total petroleum and natural gas sales	**106,849**	88,673	**394,588**	304,729
Average Daily Production				
Heavy oil (bbl/day)	**13,123**	14,450	**13,630**	11,343
Light & medium oil (bbl/day)	**4,710**	672	**1,659**	742
Natural gas (Mcf/day)	**11,634**	13,174	**12,572**	14,009
Natural gas liquids (bbl/day)	**188**	213	**201**	261
Total (boe/d)	**19,960**	17,531	**17,585**	14,681
% oil and liquids production	**90%**	87%	**88%**	84%
Average Twin Butte Realized Commodity Prices (1)				
Heavy oil ($ per bbl)	**60.28**	58.88	**66.33**	63.19
Light & Medium oil ($ per bbl)	**66.19**	75.14	**70.73**	78.50
Natural gas ($ per Mcf)	**3.78**	3.52	**3.47**	2.57
Natural gas liquids ($ per bbl)	**77.50**	76.01	**80.02**	82.74
Barrels of oil equivalent ($ per boe, 6:1)	**58.19**	54.98	**61.47**	56.71

(1) The average selling prices reported are before realized derivative instrument gains/losses and transportation charges.

	Three months ended December 31		Twelve months ended December 31	
	2013	2012	**2013**	2012
Benchmark Pricing				
WTI crude oil (US$ per bbl)	**97.44**	88.18	**97.96**	94.21
Edmonton crude oil (Cdn$ per bbl)	**86.75**	84.47	**93.40**	86.59
WCS crude oil (Cdn$ per bbl)	**69.62**	70.50	**76.15**	74.12
AECO natural gas (Cdn$ per Mcf) (2)	**3.35**	3.05	**3.01**	2.21
Exchange rate (US$/Cdn$)	**1.05**	0.99	**1.03**	1.00

(2) The AECO natural gas price reported is the average daily spot price.

Sales for the three months ended December 31, 2013 were $106.8 million, as compared to $88.7 million for the three months ended December 31, 2012, representing an increase of $18.1 million or 20%. Both production and the average realized commodity price increased from the prior period quarter, resulting in increased sales. Excluding the impact of derivative instruments, the average realized commodity price increased from $54.98 in the fourth quarter of 2012 to $58.19 during the fourth quarter of 2013. As the WCS benchmark was relatively unchanged, the 6% increase in realized price was due to a change in product mix with increased medium oil production associated with the Black Shire acquisition and decreased blending costs as a result of reduced condensate pricing during the fourth quarter of 2013. Compared to the prior year quarter, the WCS benchmark decreased 1%, and the WTI crude oil benchmark increased 11%.

Production also increased from 17,531 boe/d in the three months ended December 31, 2012 to 19,960 boe/d for the three months ended December 31, 2013. This increase of 2,429 boe/d is due the Company's drilling program and the Black Shire corporate acquisition. As the Company has not recently targeted gas-based drilling, natural gas sales have seen, and are expected to continue to see a steady decline from the comparative periods. Natural gas sales currently account for 9% of production volumes, and only 4% of sales revenue.

Sales for the year ended December 31, 2013 were $394.6 million, as compared to $304.7 million for the year ended December 31, 2012, representing an increase of $89.9 million or 30%. This increase in sales is attributed to a 20% increase in production, increased realized commodity prices and an increase in oil and liquids weighting from 84% to 88%. Production increased from 14,681 boe/d in the year ended December 31, 2012 to 17,585 boe/d in 2013. In line with increases in the WCS benchmark, the average realized commodity price before hedging increased from $56.71 per boe in the year ended December 31, 2012 to $61.47 per boe in 2013.

ROYALTIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Heavy Oil	**16,899**	12,629	**74,196**	51,607
Light & Medium oil	**3,810**	2,717	**5,936**	10,395
Natural Gas	**(471)**	(168)	**(47)**	(306)
NGLs	**885**	678	**1,944**	2,636
Total Royalties	**21,123**	15,856	**82,029**	64,332
Total royalties per boe	**11.50**	9.83	**12.78**	11.97
% of P&NG Sales	**20%**	18%	**21%**	21%

Royalties for the three months ended December 31, 2013 were $21.1 million, as compared to $15.9 million for the three months ended December 31, 2012. As a percentage of sales, the average royalty rate for the fourth quarter of 2013 increased to 20% compared to 18% in the fourth quarter of 2012, with heavy oil averaging 23%, medium & light oil averaging 13% and gas averaging (-12)%. Heavy oil royalty rates increased from the prior year quarter due to increased benchmark commodity prices in October and November and the corresponding provincial crude oil royalty calculation input prices. Light & medium oil royalty rates decreased with the addition of the former Black Shire properties, which have historically lower royalty rates. Gas royalty rates are negative during the quarter due to reduced gas production, combined with gas cost allowance credits, and credits received relating to prior year production.

Royalties for the year ended December 31, 2013 were $82.0 million, as compared to $64.3 million for the year ended December 31, 2012. As a percentage of revenues, the average royalty rate for the year ended December 31, 2013 consistent with 2012, at 21%. Despite the Company's oil weighting increasing to 88% from 84% in the prior year, this rate remained constant due to a reduction in the provincial crude oil royalty calculation heavy oil input prices in Q1 2013, resulting in lower royalties during the first part of the year, and the addition of Black Shire's lower royalty production.

OPERATING & TRANSPORTATION EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Operating expense	**38,785**	31,829	**140,124**	99,685
Transportation	**3,784**	4,555	**15,659**	13,554
Total operating & transportation expense	**42,569**	36,384	**155,783**	113,239
Operating expense per boe	**21.12**	19.73	**21.83**	18.55
Transportation expense per boe	**2.06**	2.82	**2.44**	2.52
Total per boe	**23.18**	22.55	**24.27**	21.07

Operating expenses were $38.8 million or $21.12 per boe for the quarter ended December 31, 2013 as compared to $31.8 million or $19.73 per boe for the three months ended December 31, 2012. In comparison to the prior year quarter, the Company is facing overall cost pressure due to the increasing cost of propane and increased workovers. Recently acquired properties have slightly offset increased costs in the quarter, as the former Black Shire properties have a lower operating cost than the Company's previous average.

Although they have a lower operating cost than historical Twin Butte properties, the Provost properties acquired with Black Shire bring additional exposure from power costs, as close to 30% of operating costs in the area are related to power consumption. To address this risk, the Company entered into fixed cost swaps for power costs in Q4 2013. In 2014, Twin Butte will continue this strategy to fix operating costs and protect against uncontrollable fluctuations where available.

Operating expenses were $140.1 million or $21.83 per boe for the year ended December 31, 2013, as compared to $99.7 million or $18.55 per boe for the year ended December 31, 2012. The increase on an absolute dollar basis is mainly attributable to the production growth from acquisitions, combined with internal drilling successes. On a per boe basis, cost increases are related to overall cost pressures.

Transportation expenses for the three months ended December 31, 2013 were $3.8 million or $2.06 per boe compared to $4.6 million or $2.82 per boe in the prior year comparative quarter. On both an absolute and per boe basis, transportation decreased as compared to the prior year quarter due to the addition of the former Black Shire properties, which require less truck-based transportation than Twin Butte's historical assets.

Transportation expenses for the year ended December 31, 2013 were $15.7 million or $2.44 per boe compared to $13.6 million or $2.52 per boe in the prior year. Increasing production contributed to this increase on an absolute basis, while lower transportation costs related to the former Black Shire properties caused the decrease on a per boe basis.

The Company has combined operating and transportation costs of $23.18 per boe for the quarter, an increase from $22.55 per boe for the comparable period of 2012. This 3% increase is driven by increases in operating costs. The Company targets all-in operating and transportation costs of $22 per boe for 2014.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
G&A expense	**5,324**	4,715	**19,360**	16,201
Recoveries	**(990)**	(527)	**(3,364)**	(2,404)
Capitalized G&A expense	**(816)**	(851)	**(3,479)**	(3,190)
Total net G&A expense	**3,518**	3,337	**12,517**	10,607
Total net G&A expense per boe	**1.92**	2.07	**1.95**	1.97
Transaction expense	**2,138**	1,233	**2,193**	4,239
Transaction expense per boe	**1.17**	0.76	**0.34**	0.79

General and administrative expenses, net of recoveries and capitalized G&A, were $3.5 million or $1.92 per boe for the current quarter as compared to $3.3 million or $2.07 per boe in the prior year comparative quarter. The Company's expenses increased slightly, due to additional staff following the Black Shire acquisition, although were slightly offset by increased capital spending which increased G&A recoveries. On a per boe basis, G&A has decreased, as production increased at a greater rate than G&A due to acquisition synergies. Net G&A expense for the year ended December 31, 2013 was $12.5 million or $1.95 per boe, compared to $9.0 million of $1.97 per boe in the prior year.

During the fourth quarter, the Company incurred transaction costs related to the corporate acquisition of Black Shire, specifically related to advisory, stock exchange, legal and bank fees. Total transaction costs in 2013 totalled $2.1 million. Transaction expenses in 2012 include $2.2 million for the Emerge acquisition in the first quarter, $0.8 million for Avalon in the third quarter and $1.2 million for Waseca in the fourth quarter.

In line with continued acquisition synergies, the Company targets G&A for 2014 to be less than $2.00 per boe.

SHARE-BASED PAYMENT EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Total	**1,630**	1,549	**4,913**	4,386
Total per boe	**0.89**	0.96	**0.77**	0.82

During the three months ended December 31, 2013, the Company expensed $1.6 million in share-based payment expense as compared to $1.5 million in the three month period ended December 31, 2012. The Board of Directors declared the annual performance factor to be 1.5 for performance awards vesting in 2014. The annual performance factor was 2 for awards vesting in 2013. The performance factor resulted in additional share-based payment expense during the quarter, as additional shares will be issued for performance share awards maturing in 2014.

The Company awarded 163,560 share awards and 499,559 performance share awards in the fourth quarter of 2013 as compared to 177,981 share awards and 538,915 performance share awards in the fourth quarter of 2012. Total share awards forfeited due to employee departures were 347,143 in the quarter versus 269,030 awards forfeited in the fourth quarter last year.

During the year ended December 31, 2013, the Company expensed $4.9 million in stock-based compensation as compared to $4.4 million in the prior year. As this is the second year of the program, costs have increased due to expense related to both current year and prior year grants and dividend accumulation.

At December 31, 2013, the Company has 3,060,543 restricted share awards, 2,292,060 performance share awards and 640,434 options outstanding.

FINANCE EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Interest and bank charges	**2,860**	1,906	**8,275**	5,679
Interest on convertible debentures (1)	**262**	–	**262**	–
Accretion on convertible debentures (1)	**61**	–	**61**	–
Accretion on decommissioning provision	**725**	495	**2,486**	1,623
Total finance expense	**3,908**	2,401	**11,084**	7,302
Total interest per boe	**1.70**	1.18	**1.33**	1.06
Total accretion per boe	**0.43**	0.31	**0.40**	0.30
Total finance expense per boe	**2.13**	1.49	**1.73**	1.36

(1) Convertible debentures were issued on December 13, 2013, resulting in 18 days of finance expenses in 2013.

For the three months ended December 31, 2013, finance charges were $3.9 million as compared to $2.4 million in the three month period ended December 31, 2012. This increase is due to increased average bank debt for the quarter, which was $216 million compared to $195 million in the prior year quarter, and interest on the convertible debentures, issued in December 2013 with a face value of $85 million. For the year ended December 31, 2013, finance charges also increased and were $11.1 million as compared to $7.3 million in the prior year.

The Company's current interest charge on the operating line is bank prime of 3.0% plus a margin of 1.25% for a total rate of 4.25% and the Company's convertible debentures pay an interest rate of 6.25% annually. The combined effective interest rate for the quarter was 4.1%, as Bankers Acceptances were utilized to reduce the bank rate, and the debentures were only outstanding for a portion of the quarter.

DERIVATIVE ACTIVITIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Realized gain (loss)	**2,597**	7,796	**(4,114)**	29,401
Cash proceeds – Swaptions	**–**	–	**7,943**	–
Unrealized gain (loss) – Financial derivatives	**(11,990)**	18,511	**(41,543)**	32,510
Gain (loss) and proceeds on derivatives	**(9,393)**	26,307	**(37,714)**	61,911
Realized gain (loss) on derivatives per boe	**1.41**	4.83	**(0.64)**	5.47
Cash proceeds derivatives per boe – Swaptions	**–**	–	**1.24**	–
Unrealized gain (loss) on derivatives per boe	**(6.53)**	11.48	**(6.47)**	6.05
Gain (loss) and proceeds per boe	**(5.12)**	16.31	**(5.87)**	11.52

As part of the financial management strategy to protect cash flows available for the payment of dividends, the Company has adopted a commodity price and interest rate risk management program. The purpose of the program is to stabilize and hedge future cash flows against the unpredictable commodity price environment, with an emphasis on protecting downside risk. During the fourth quarter of 2013, Twin Butte entered into fixed price crude oil and natural gas swaps for 2014 and 2015 production periods.

With derivative instruments, there is a risk that the counterparty could become illiquid or that Twin Butte may not have the actual sales volumes to offset the hedge position. To manage risk, the Company's counterparties on derivative instruments are major Canadian and international banks and the maximum volumes hedged for the subsequent 12 months are limited to 80% of current production.

In Q4 2013, following the acquisition of Black Shire, the Company entered into fixed price swaps with its power provider in order to stabilize future operating costs. In 2013, power costs averaged $80 per megawatt hour, but frequently were over $100 per megawatt hour. As power costs make up a significant percentage of operating expense for the acquired wells, these contracts will assist the Company in maintaining low operating costs in these areas. Current contracts are for less than 50% of estimated power usage and the company may increase the level of fixed power contracts in 2014.

Realized gains and cash proceeds

The Company realized a total gain of $2.6 million ($1.41 per boe) for the three month period ended December 31, 2013, compared to a realized gain of $7.8 million ($4.83 per boe) for the prior quarter comparative period. During the quarter, the total gain was due to fixed price swaps, and was comprised of a $1.8 million gain on crude oil sales price derivatives and a gain of $0.8 million on natural gas sales price derivatives.

For the year ended December 31, 2013, The Company realized total cash proceeds on financial derivatives in the amount of $3.8 million ($0.60 per boe) comprised of a $4.1 million ($0.64 per boe) loss from fixed price swaps and $7.9 million ($1.24 per boe) in proceeds from crude oil swaptions sold. This compares to a realized gain on fixed price swaps of $29.4 million ($5.47 per boe) for the prior year. The realized gain on fixed price swaps in 2013 was split between a gain of $4.2 million for natural gas sales price derivatives, a loss of $8.3 million for crude oil sales price derivatives.

Unrealized derivative assets and liabilities

As at December 31, 2013, the Company has a net unrealized financial derivative liability in the amount of $32.2 million. This net unrealized loss position reflects strong WTI benchmark forward pricing and narrow WTI to WCS forward differentials for 2014. If WTI and WCS pricing meets the forecasted benchmarks, these loss positions would be realized alongside increased sales due to the high commodity pricing.

The Company has recognized an unrealized loss on financial derivatives in the amount of $12.0 million for the three month period ended December 31, 2013 as compared to $18.5 million unrealized gain for the prior year comparative period. This unrealized loss is due to a narrowing of the WCS to WTI forward differential, which caused the WCS fixed price oil swaps to move to a liability position as of December 31, 2013.

For the year ended December 31, 2013, the Company has recognized an unrealized loss of $41.5 million, as the net balance of outstanding derivatives was an unrealized liability at December 31, 2013, reduced from an asset position as at December 31, 2012.

The following is a summary of derivatives as at December 31, 2013 and their related fair market values (unrealized gain (loss) positions):

Crude Oil Sales Price Derivatives

Daily barrel (bbl) quantity	Term of contract	WTI[1] Fixed price per bbl ($CAD)	WCS [2] Fixed Price per bbl ($CAD)	Fixed price per bbl WCS [2] vs. WTI [1] ($CAD)	Fixed written call price per bbl WTI [1] ($USD)	Fair market value $000's
3,500	January 1, 2014 to December 31, 2014	$95.89				(7,892)
12,400	January 1, 2014 to June 30, 2014	$96.21				(17,713)
8,650	July 1, 2014 to September 30, 2014	$94.69				(5,110)
500	July 1, 2014 to December 31, 2014	$99.25				(78)
7,500	October 1, 2014 to December 31, 2014	$94.66				(3,033)
1,000	January 1, 2015 to March 31, 2015	$97.46				37
1,500	October 1, 2014 to December 31, 2014		$75.00			(224)
1,000	January 1, 2014 to December 31, 2014			(22.00)		444
2,000	January 1, 2014 to June 30, 2014			(19.55)		1,783
4,000	July 1, 2014 to December 31, 2014			(21.90)		(140)
2,000	July 1, 2014 to September 30, 2014			(21.95)		(57)
1,000	January 1, 2015 to December 31, 2015			(19.75)		481
1,300	January 1, 2014 to December 31, 2014				$110.00	(205)
Crude oil fair value position						(31,707)

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Natural Gas Sales Price Derivatives

Daily giga-joule (GJ) quantity	Term of contract	Fixed price per GJ AECO Daily	Fair Market Value *$000's*
8,000	January 1, 2014 to December 31, 2014	$3.53	(531)
Natural gas fair value position			(531)

Power Purchase Price Derivatives

Daily Megawatt (MW) hours quantity	Term of contract	Fixed price per MW	Fair Market Value *$000's*
288	January 1, 2014 to December 31, 2014	$55.05	49
192	January 1, 2015 to December 31, 2015	$53.02	(48)
Power purchase contract fair value position			1

Gain/Loss on Dispositions

During the year ended December 31, 2013 the Company disposed of the Jayar property for proceeds of $19.5 million, resulting in a gain of $6.5 million. Jayar was producing approximately 300 boe/d and was 72% natural gas. Total dispositions of Property and Equipment (PP&E) and Exploration and Evaluation (E&E) assets in 2013, which included Jayar and several other non-core properties, totaled $29.6 million ($6.9 million – December 31, 2012). A $5.4 million net gain was recognized on these transactions ($3.0 million gain – December 31, 2012).

DEPLETION, DEPRECIATION & IMPAIRMENT

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2013**	2012	**2013**	2012
Depletion & Depreciation	**44,448**	32,264	**134,725**	99,471
Depletion & Depreciation per boe	**24.20**	20.00	**20.99**	18.51

For the three month period ended December 31, 2013, depletion and depreciation of capital assets was $44.4 million or $24.20 per boe compared to $32.3 million or $20.00 per boe for the prior year comparative period. On an absolute basis, this increase relates to increased production associated with the acquisition of Black Shire, and increased depletion following the reduction in reserves associated with the Heavy Oil CGU detailed below. The rate per boe also increased from the prior period quarter due to the Heavy Oil reserve decrease.

For the year ended December 31, 2013, depletion and depreciation of capital assets was $134.7 million or $20.99 per boe compared to $99.5 million or $18.51 per boe in the prior year. This increase is due to the high depletion rate in the fourth quarter, and acquisitions in 2012, which had a higher cost base than historical Twin Butte.

At December 31, 2013, the Company assessed for indicators of impairment for all of its Cash Generating Units (CGUs). Reductions to future natural gas benchmark pricing in years following 2014 indicated that CGUs that produce a high percentage of natural gas may be impaired. Further, external engineer reserve valuations for the Heavy Oil CGU decreased from the prior year, which also indicated potential impairment for this non-gas CGU. Twin Butte estimated the recoverable amount for these CGUs based on the fair value less costs to sell, determined with an after-tax discount rate of 9.5%, forecasted cash flows over the estimated life of reserves, and an independent industry reserve engineer price deck. Based on the assessment, the carrying value of the Heavy Oil and Plains CGUs were determined to be higher than their respective recoverable amounts and a total non-cash impairment charge of $49.5 million was recognized. Goodwill in the amount of $31.4 million associated with the Heavy Oil CGU was also impaired. At December 31, 2012, due to sustained low natural gas current and forward prices, the Company impaired the Plains, West Central and Deep Basin CGUs for a total of $17.2 million.

There were no impairment indicators noted for E&E assets.

INCOME TAXES

Deferred tax amounted to a $19.6 million recovery for the three month period ended December 31, 2013 compared to $2.1 million expense for the three month period ended December 31, 2012. This recovery is the result of impairment losses and losses on unrealized derivative contracts.

Deferred tax expense for the year ended December 31, 2013 amounted to a $29.0 million recovery, as compared to $13.6 million expense for the prior year. This recovery is also the result of impairment losses and losses on unrealized derivative contracts.

The Company has existing tax losses and pools of approximately $784 million at December 31, 2013. These income tax pools are deductible at various rates and annual deductions associated with the initial pools will decline over time.

NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Three months ended December 31		Twelve months ended December 31	
($000's except per share amounts)	**2013**	2012	**2013**	2012
Net Income (loss)	**(88,028)**	(5,381)	**(115,633)**	31,530
Net Income (loss) per share	**(0.28)**	(0.02)	**(0.44)**	0.15

Net and comprehensive income for the three month period ended December 31, 2013 was a net loss of $88.0 million, compared to a net loss of $5.4 million in the prior year comparative period. This decrease was due to impairment losses and an unrealized mark to market loss on derivatives. Net and comprehensive income for the year ended December 31, 2013 was net loss of $115.6 million, compared to net income of $31.5 million in the prior year. This decrease is also due to impairment losses and an unrealized mark to market loss on derivatives.

SELECTED ANNUAL INFORMATION

	Twelve months ended December 31		
($000's except per share amounts)	**2013**	2012	2011
Petroleum and natural gas sales	**394,588**	304,729	146,577
Net Income (loss)	**(115,633)**	31,530	(19,021)
Per share basic	**(0.44)**	0.15	(0.14)
Per share diluted	**(0.44)**	0.15	(0.14)
Total assets	**1,165,638**	845,261	340,664
Total non-current financial liabilities	**329,590**	193,625	3,102
Dividends declared	**52,286**	37,249	–

QUARTERLY FINANCIAL SUMMARY

The following table highlights Twin Butte's performance for each of the past eight quarters:

($000's, except per share amounts)	**Q4 2013**	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Average production (boe/d)	**19,960**	16,263	16,849	17,254	17,531	13,752	14,193	13,228
Petroleum and natural gas sales	**106,849**	117,478	98,497	71,764	88,673	73,386	70,173	72,497
Operating netback (per boe) (1)	**24.92**	26.13	24.98	24.12	26.27	33.80	28.95	26.71
Funds flow from operations (2)	**36,978**	34,899	33,058	32,423	37,754	38,119	33,762	26,400
Per share basic	**0.12**	0.14	0.13	0.13	0.16	0.19	0.18	0.14
Per share diluted	**0.12**	0.14	0.13	0.13	0.16	0.19	0.17	0.14
Net income (loss)	**(88,028)**	8,111	(6,082)	(29,633)	(5,381)	(7,411)	29,529	14,983
Per share basic	**(0.28)**	0.03	(0.02)	(0.12)	(0.02)	(0.04)	0.15	0.08
Per share diluted	**(0.28)**	0.03	(0.02)	(0.12)	(0.02)	(0.04)	0.15	0.08
Corporate acquisitions (3)	**356,521**	–	–	–	134,972	88,369	–	203,000
Capital expenditures (4)	**33,632**	9,048	14,871	19,625	38,530	17,369	24,126	7,717
Total assets	**1,165,638**	802,916	790,056	815,040	845,261	690,240	588,893	583,439
Net debt excluding financial derivatives	**361,612**	179,013	193,750	200,542	201,703	146,843	124,459	126,466

(1) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales, realized gains (losses) on derivatives, less royalties, operating and transportation expenses.

(2) Funds flow from operations and funds flow from operations netback are non-GAAP measures that represent the total and the average per boe, respectively, of cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

(3) Corporate acquisitions are a non-GAAP measure and include total consideration plus working capital deficiency acquired in a corporate acquisition.

(4) Capital expenditures are a non-GAAP measure, calculated as the purchase or sale price of an asset, plus development capital expenditures added to PP&E. Corporate acquisitions are excluded from this measure.

Quarterly variances in sales are connected to changes in production volumes and prices. In the first quarter of 2012, the Company added production volumes through the acquisition of Emerge Oil & Gas Inc. The Company also completed the acquisition of Avalon Exploration Ltd. in Q2 2012, and Waseca Energy in Q4 2012, resulting in increased production into the second half of 2012. Volatile commodity prices in 2013 reduced sales in Q1, but increased sales in Q2 and Q3 2013. In Q4 2013, the Company added production volumes with the acquisition of Black Shire Energy Inc., exiting the year with approximately 23,000 boe/d of production.

Through its strategy to protect cash flows and maintain its dividend, Twin Butte hedges a relatively large percentage of production using financial derivatives. As such, commodity price swings in oil have a moderated effect on funds flow from operations, as only current quarter realized cash gains or losses are included. Funds flow from operations grew with production throughout 2012, before setbacks at Primate in January 2013. In Q3 2013, funds flow from operations increased slightly from Q1 and Q2 2013, as sales increases were mostly offset by realized losses on financial derivatives. In Q4 2013, despite reduced pricing from Q3, the higher netback on the former Black Shire properties increased funds flow from operations.

Quarterly variances in net income, however, are largely driven by non-cash items, such as unrealized gains or losses on derivatives, deferred tax expense or recovery, and gains or losses on asset acquisitions and dispositions. In Q2 2012, net income contains unrealized gains on derivatives. Conversely, in Q1 2013 the net loss was due to unrealized losses on derivatives. In the second quarter of 2013, the Company recorded further unrealized losses on derivatives, and a loss on the sale of a non-core asset. In Q3 2013, net income was due to gains on the sale of Jayar and an additional non-core asset. Unrealized losses on derivatives and impairment losses reduced net income in Q4 2013.

DIVIDENDS

In addition to the cash dividend and Dividend Reinvestment Program ("DRIP"), in Q2 2013 Twin Butte initiated a Stock Dividend Program ("SDP"). This program, available to both Canadian and non-Canadian investors, allows shareholders to choose to receive dividends in the form of shares of Twin Butte at a 5% discount to the current weighted average price in lieu of a cash dividend. Cash dividends were first declared in January 2012, and the DRIP program was initiated in Q3 2012.

For the three months ended December 31, 2013, Twin Butte paid cash dividends of $13.0 million and $1.2 million was invested in Twin Butte shares through the DRIP and SDP, compared to $9.0 million paid in cash dividends and $1.5 million invested in shares in the fourth quarter of 2012.

For the year ended December 31, 2013, Twin Butte paid cash dividends of $44.6 million and $5.6 million was invested in Twin Butte shares through the DRIP and SDP. In 2012, Twin Butte paid cash dividends of $32.2 million and $1.7 million was invested in Twin Butte shares.

Cash dividends declared, for the three and year ended December 31, 2013, which includes dividends declared and payable on December 31, 2013 and is net of the DRIP and SDP, were $14.2 million and $46.3 million, respectively. In 2012, cash dividends declared for the three months and year ended December 31, 2012 were $9.4 million and $35.6 million, respectively.

FUNDS FLOW FROM OPERATIONS (1), TOTAL PAYOUT RATIO (3), AND NETBACKS

Funds flow from operations and the payout ratio are non-GAAP measures. Funds flow from operations represents cash flow from operating activities adjusted for expenditures on decommissioning activities and changes in non-cash operating working capital. The payout ratio is calculated as dividends paid and capital expenditures (excluding corporate acquisitions) as a percentage of funds flow from operations. Twin Butte considers these to be key measures of performance as they demonstrate the Company's ability to generate the cash flow necessary to fund dividends and capital investment and ultimately, satisfy corporate strategy.

	Three months ended December 31		Twelve months ended December 31	
($000's except per share amounts)	**2013**	2012	**2013**	2012
Cash flow from operating activities	**49,161**	47,197	**130,738**	131,767
Expenditures on decommissioning liability	**1,455**	483	**3,287**	1,140
Change in non-cash working capital	**(13,638)**	(9,926)	**3,333**	3,127
Funds flow [1]	**36,978**	37,754	**137,358**	136,034
Funds flow per share	**0.12**	0.16	**0.52**	0.66
Dividends declared	**(15,577)**	(10,579)	**(52,286)**	(37,249)
Capital Expenditures [2]	**(33,632)**	(38,530)	**(77,176)**	(87,742)
Payout ratio [3]	**133%**	130%	**94%**	92%
Reinvested dividends (DRIP and SDP)	**1,369**	1,759	**5,403**	2,299
Cash dividends declared	**(14,208)**	(8,820)	**(46,883)**	(34,950)
Total payout ratio (net of DRIP and SDP) [3]	**129%**	125%	**90%**	90%

(1) Funds flow from operations is a non-GAAP measure that represents cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

(2) Capital expenditures is a non-GAAP measure, calculated as the purchase or sale price of an asset, plus development capital expenditures. Corporate acquisitions are excluded from this measure.

(3) Payout ratio is a non-GAAP measure, calculated as the sum of dividends and capital expenditures, divided by funds flow from operations. Total Payout Ratio (net of DRIP and SDP) is the Payout ratio, adjusted for dividends paid or reinvested as stock. The DRIP program was initiated with the August dividend payment on September 17, 2012, and the SDP program was initiated in May 2013.

Twin Butte's corporate strategy aims to provide shareholders with long term total returns comprised of both income and moderate growth, with a focus on dividend sustainability. The Company targets 2–4% production growth and a total payout (net of DRIP and SDP) that will not exceed cash flow on an annual basis. The Company uses the total payout ratio to monitor performance, and will adjust capital expenditures to ensure that the total payout does not exceed cash flow, on an on-going basis where required. For the three month period ended December 31, 2013, the total payout ratio was 133%. The year-to-date payout ratio for 2013 is 90%. Capital expenditures are net of proceeds on the disposition of Jayar, which reduced the payout ratio in the third quarter of 2013 and year-to-date. In Q4 2013, the Company's payout ratio exceeded 100%, as proceeds from the sale of Jayar were reinvested in the form of additional capital spending.

Funds flow from operations for the three month period ended December 31, 2013 was $37.0 million, in line with fourth quarter 2012 funds flow of $37.8 million, as increased sales were matched by increased royalties and operating costs. This represents $0.12 per diluted share compared to $0.16 per diluted share for in 2012 and $0.14 in the third quarter of 2013. The decrease in funds flow per share from the prior year quarter is due to an increase in shares outstanding.

The following table summarizes netbacks for the past eight quarters on a barrel of oil equivalent basis:

($ per boe)	**Q4 2013**	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Petroleum and natural gas sales	**58.19**	78.52	64.24	46.21	54.98	58.01	54.33	60.23
Royalties	**(11.50)**	(17.51)	(13.39)	(9.14)	(9.83)	(11.40)	(12.84)	(14.52)
Cash gain (loss) on financial derivatives	**1.41**	(10.87)	0.01	11.26	4.83	8.02	6.91	2.10
Operating expense	**(21.12)**	(21.53)	(22.92)	(21.88)	(19.73)	(18.38)	(17.19)	(18.62)
Transportation expense	**(2.06)**	(2.48)	(2.96)	(2.33)	(2.82)	(2.45)	(2.26)	(2.48)
Operating netback (1)	**24.92**	26.13	24.98	24.12	27.43	33.80	28.95	26.71
General and administrative expense	**(1.92)**	(1.62)	(2.05)	(2.21)	(2.07)	(2.22)	(1.57)	(2.03)
Transaction costs	**(1.17)**	–	–	(0.03)	(0.76)	(0.62)	(0.20)	(1.63)
Interest and bank charges	**(1.70)**	(1.18)	(1.37)	(1.00)	(1.18)	(1.00)	(1.05)	(1.13)
Funds flow from operations (2)	**20.13**	23.33	21.56	20.88	23.42	29.96	26.13	21.92

(1) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales, realized gains (losses) on derivatives, less royalties, operating and transportation expenses.

(2) Funds flow from operations is a non-GAAP measure that represents the total of funds provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

CAPITAL EXPENDITURES AND PP&E ADDITIONS

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2013**	2012	**2013**	2012
Land acquisition	**2,443**	2,056	**3,766**	4,266
Geological and geophysical	**222**	436	**2,420**	879
Drilling and completions	**20,302**	10,080	**65,234**	37,291
Equipping and facilities	**10,164**	4,653	**31,538**	14,485
Other	**817**	851	**3,479**	3,190
Development capital	**33,948**	18,076	**106,437**	60,111
Property acquisitions – Cash paid	**–**	20,454	**370**	34,500
Property dispositions – Cash received	**(316)**	–	**(29,631)**	(6,869)
Capital expenditures (1)	**33,632**	38,530	**77,176**	87,742
Net other additions to PP&E (2)	**47,178**	2,335	**24,499**	11,484
Corporate acquisition additions to PP&E	**422,644**	114,631	**422,644**	406,000
Total net additions to PP&E	**503,454**	155,496	**524,319**	505,226

(1) Capital expenditures is a non-GAAP measure and is defined as the total cash consideration paid or received for property acquisitions and dispositions, plus development and exploration capital expenditures. This measure is used by management to calculate the Payout and Total Payout Ratios.

(2) Net other additions to PP&E reconciles the Non-GAAP Capital Expenditures measure to the IFRS measure of capital additions, and is the net adjustments made to account for the assets purchased under IFRS 3 – Business Combinations, assets sold for cash, reclassification of E&E assets, and corresponding changes in PP&E due to changes in the decommissioning liability.

During the fourth quarter of 2013, the Company invested $33.9 million on development capital, an increase from $18.1 million in development capital invested in Q4 2012. The Company's development capital expenditures for the quarter were focused in the Heavy Oil and Provost areas, with successful drilling of 9 (9.0 net) oil wells at Wildmere; 3 (3.0 net) wells at Maidstone; 3 (1.65 net) wells at Frog Lake; 2 (2.0 net) wells at each of Celtic, Ear Lake, and Provost, as well as 4 (3.67 net) wells at various other heavy oil properties.

The Company completed the corporate acquisition of Black Shire, as well as property dispositions for cash proceeds of $0.3 million during the quarter. In the fourth quarter of 2012, the Company completed the corporate acquisition of Waseca and a property acquisition in the Auburndale area.

For the year ended December 31, 2013, the Company completed the corporate acquisition of Black Shire, property dispositions for cash proceeds of $29.6 million and property acquisitions for $0.4 million. During 2012, the company completed the corporate acquisitions of Emerge, Avalon, and Waseca, property acquisitions in the Swimming and Auburndale areas, and dispositions for proceeds of $6.9 million.

Drilling Results

Three months ended December 31	**2013**		2012	
	Gross	**Net**	Gross	Net
Crude oil	**25**	**23.3**	20	20.0
Dry and abandoned	**1**	**1.0**	3	3.0
Total	**26**	**24.3**	23	23.0
Success rate (%)		**96%**		87%

Three months ended December 31	**2013**		2012	
	Gross	**Net**	Gross	Net
Crude oil	**90**	**88.3**	91	73.2
Dry and abandoned	**7**	**7.0**	4	4.0
Total	**97**	**95.3**	95	77.2
Success rate (%)		**93%**		95%

Undeveloped Land

The Company's undeveloped land holdings have decreased from the December 31, 2012, as conversions from drilling, dispositions and expiries were greater than purchases.

At December 31,	**2013**	2012
Gross Acres	**958,432**	1,007,256
Net Acres	**418,382**	455,990

LIQUIDITY AND CAPITAL RESOURCES

The Company evaluates its ability to carry on business as a going concern on a quarterly basis, with the key indicator being whether the non-GAAP measure, funds flow from operations, will be sufficient to cover all obligations, specifically the non-GAAP measure of net debt. Funds flow from operations represents cash flow from operating activities adjusted for expenditures on decommissioning activities and changes in non-cash operating working capital. Net debt is defined as the total of bank indebtedness, account payable, accrued liabilities, and cash dividends payable, less the total of accounts receivable, deposits and prepaids. Twin Butte considers this ratio to be a key measure of liquidity and the management of capital resources.

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2013**	2012	**2013**	2012
Funds flow (1)	**36,978**	37,754	**137,358**	136,034
Annualized funds flow (2)	**147,912**	151,016	**137,358**	136,034
Net debt (3)	**361,612**	201,703	**361,612**	201,703
Net debt to annualized funds flow (4)	**2.4**	1.3	**2.6**	1.5

(1) Funds flow from operations is a non-GAAP measure that represents the total of cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

(2) Funds flow from operations – annualized is a non-GAAP measures that represents funds flow for the period, multiplied to represent 12 months, where necessary.

(3) Net Debt is a non-GAAP measure representing the total of bank indebtedness, convertible debenture liability, accounts payable, accrued liabilities and cash dividend payable, less the total of accounts receivable, deposits and prepaids.

(4) The ratio of net debt to funds flow – annualized is a non-GAAP measure provided to further understand the liquidity of the Company. This ratio is calculated as net debt divided by annualized funds flow.

For the three months ended December 31, 2013, the annualized net debt to funds flow ratio was 2.4, an increase from the prior year quarter, which was 1.3. This increase is driven by the Black Shire acquisition in November, which added the acquisition's full debt load and less than two months of funds flow during the quarter. For the year ended December 31, 2013, the annualized net debt to funds flow ratio was 2.6, compared to the prior year of 1.5. This increase is also due to increased net debt in November with less than two months of cash flow related to this increased debt load. Based on net debt of $361.4 million at December 31, 2013, and forecasted annual funds flow for 2014, we expect the net debt to annualized funds flow ratio to be less than 1.8 in 2014, with a target exit ratio of less than 1.75.

The Company reviews capital expenditures on an on-going basis to ensure that funds flow will provide adequate funding. In cases where funds flow is not adequate, the Company may adjust capital expenditures to manage debt levels. Diligent monitoring of funds flow from operations, as well as debt levels, allows Twin Butte to maintain an undrawn portion of $148 million on the Company's dedicated credit facility of $400 million. Due to the undrawn portion on the credit facility, as well as positive cash provided by operating activities, the Company believes it has the ability to meet its current obligations.

In the management of capital, the Company includes working capital and net debt in the definition of capital. The Company's share capital is not subject to external restrictions; however, its credit facility value is based primarily on its petroleum and natural gas reserves and covenants detailed below. The Company confirms there are no off-balance sheet financing arrangements.

Credit Facility

As at December 31, 2013 the Company's dedicated facility consisted of a revolving line of credit of $375 million and an operating line of credit of $25 million, available on an annual revolving basis. The annual credit facility review was completed in May 2013 and the expiry of the current annual revolving period is April 29, 2014. In connection with the acquisition of Black Shire Energy on November 5, 2013, this facility was increased to the current level of $400 million.

This facility is extendible at the request of the Company for a further 364 days, subject to approval of the lenders and is repayable one year after the expiry of the revolving period if not extended. The credit facility is with a syndicate of six Canadian chartered or international banks and provides that advances may be made by way of Canadian prime rate and U.S. base rate loans, bankers' acceptances, LIBOR Loans, or standby letters of credit/guarantees. Covenants on this facility include an adjusted current ratio of 1:1, which includes the undrawn portion of the credit facility as a current asset, and limits on financial commodity agreements which require total agreements to be less than 80% the average daily production of the prior quarter at the time the agreement is signed. As the commodity agreements extend beyond 12 months, the maximum percentage decreases to 70%, and then to 60% for those agreements with terms greater than 24 months. At December 31, 2013, the Company has met all covenants pertaining to this loan agreement. Twin Butte is not in default in relation to this agreement and was not required to make any repayments.

Interest rates on Canadian prime rate loans fluctuate based on revised pricing grid and range from Bank of Canada ("bank") prime plus 1% to bank prime plus 2.5%, depending upon the Company's debt to EBITDA ratio for the preceding twelve months in categories ranging from one to greater than three times. A debt to EBITDA ratio of less than one has interest payable at the bank's prime lending rate plus 1%. A debt to EBITDA ratio greater than three has interest payable at the bank's prime lending rate plus 2.5%. The borrowing base of the facility is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment. The Company's credit facility is subject to semi-annual review by the bank and is secured by a debenture and a general security agreement covering all assets of the Company.

Convertible Debentures

In December 2013, the Company completed the issuance of convertible unsecured subordinated debentures (the "Debentures") for gross proceeds of $85.0 million ($81.4 million net of issuance costs) at a price of $1,000 per debenture. The debentures pay interest at a rate of 6.25% per annum, payable in arrears on a semi-annual basis on June 30 and December 31 of each year, commencing on June 30, 2014. The debentures mature on December 31, 2018.

The debentures are convertible at the option of the holder into common shares at a fixed conversion price of $3.05 per share. After December 31, 2016, the Company may redeem the debentures in whole or part provided the common shares' weighted average trading price during a specified period prior to redemption is not less than 125% of the conversion price.

SHARE CAPITAL

In the fourth quarter of 2013, the Company completed the corporate acquisition of Black Shire through a combination of cash and the issuance of 54,012,276 shares. In association with the acquisition, the Company also issued 35,898,000 shares through a private placement of subscription receipts. Vested share and performance share awards were also exercised, resulting in the issuance of 537,152 shares. For the year ended December 31, 2013, 2,154,874 shares were issued on account of vested share and performance share awards that were exercised.

As of March 20, 2014 the Company has 345,071,217 Common Shares, 640,434 stock options and 6,118,169 share awards, including reinvested dividends and performance multipliers, outstanding.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company enters into short term contractual obligations in the normal course of business, including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations and employee agreements. These obligations are of a recurring, consistent nature and impact cash flows in an ongoing manner.

Twin Butte also has long-term contractual obligations and commitments. The Company is responsible for the retirement of long-lived assets related to its oil and gas properties at the end of their useful lives. Twin Butte has recognized a liability of $182 million (December 31, 2012 – $89.0 million) based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation or actual costs.

Additional contractual obligations and commitments are as follows:

As at December 31, 2013	Less than one year	One to three years	Three to five years	Total
Derivative liability	34,983	–	–	34,983
Bank indebtedness – principal (1)	–	252,181	–	252,181
Bank indebtedness – interest	10,087	3,362	–	13,449
Convertible debentures – principal (2)	–	–	85,000	85,000
Convertible debentures – coupon	5,312	10,625	10,625	26,562
Purchase obligations (3)	5,787	3,763		9,550
Other (4)	2,028	6,138	1,158	9,324
	58,197	276,069	96,783	431,049

(1) Repayment of this principal amount in one to three years is based on the revolving debt agreement currently in place and does not consider the annual review for extension. The next review is scheduled for April 2014, at which Management fully expects the facility to be extended.

(2) Repayment of the Convertible Debentures assumes that all holders of the debentures will not convert their holdings into shares.

(3) Purchase obligations include contracts to purchase and consume electricity during 2014 and 2015. The fair value of these contracts is recorded as a financial asset.

(4) Other includes contractual obligations and commitments for office rent and equipment.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and deferred income taxes. Twin Butte is also involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favor, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters would have a material adverse impact on its financial position, results of operations or liquidity.

RELATED PARTY TRANSACTIONS

During the three month period ended December 31, 2013, the Company incurred costs totaling \$2.9 million (\$2.0 million – December 31, 2012) for oilfield services and legal counsel rendered by three companies of which an officer and director of Twin Butte is a director. During the year ended December 31, 2013, the Company incurred related party costs totaling \$8.0 million (\$6.9 million – December 31, 2012).

These costs were incurred in the normal course of business and were recorded at the amount exchanged between the parties. As at December 31, 2013, the Company had \$1.7 million (\$4.3 million – December 31, 2012) included in accounts payable and accrued liabilities related to these transactions.

SUBSEQUENT EVENTS

Crude Oil Sales Price Derivative Contracts

Subsequent to December 31, 2013 the Company entered into several crude oil price derivatives. The average barrels and prices for these contracts are as follows:

Daily barrel (bbl) quantity	Term of contract	WTI (1) Fixed price per bbl (\$CAD)	WCS (2) Fixed Price per bbl (\$CAD)	Fixed price per bbl WCS (2) vs. WTI (1) (\$CAD)
4,318	February 1, 2014 to December 31, 2014			(\$21.19)
3,500	April 1, 2014 to June 30, 2014			(\$20.04)
1,500	January 1, 2015 to June 30, 2015		\$77.68	
500	January 1, 2015 to December 31, 2015		\$77.75	
1,000	April 1, 2015 to June 30, 2015	\$99.00		
2,500	January 1, 2015 to December 31, 2015	\$98.97		

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Natural Gas Sales Price Derivative Contracts

Subsequent to December 31, 2013, the Company entered into natural gas price derivative contracts for the period of February 1, 2014 to December 31, 2014. The Company will swap 1,500 giga-joules (GJ) per day of Natural Gas at a fixed price of \$3.84 per GJ, based on AECO daily pricing.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the annual Financial Statements for the year ended December 31, 2013 is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 9 – valuation of property and equipment;
- Note 13 – measurement of decommissioning provision;
- Note 14 – measurement of share-based compensation; and
- Note 19 – income tax expense.

The Company's significant areas of estimation uncertainty have not changed during the period. In accordance with new standards adopted, the Company has provided additional estimation and assumption disclosure regarding the valuation of financial instruments in Note 5 to the financial statements.

Judgements

In the process of applying the Company's accounting policies, management has made the following judgements, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the financial statements.

(a) Exploration and evaluation assets

The decision to transfer assets from exploration and evaluation to property and equipment is based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability.

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporate the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs (Note 9).

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is highly likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

(c) Depletion of oil and gas assets

Oil and gas properties are depleted using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depletion could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves (Note 9).

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Company, and grouped the properties into cash generating units on the basis of their ability to generate independent cash inflows, similar reserve characteristics, geographical location, and shared infrastructure.

(e) Impairment indicators and calculation of impairment

At each reporting date, Twin Butte assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property and equipment are not recoverable, or impaired. Such circumstances include incidents of deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves. At December 31, 2013, Management exercised judgement and determined that there were impairment indicators present for certain CGUs. When management judges that circumstances clearly indicate impairment, property and equipment and exploration and evaluation assets are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value in use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions that are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates, as well as future development and operating costs.

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

The Company has adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2013. These changes were made in accordance with the applicable transitional provisions.

(i) *IFRS 10 Consolidated Financial Statements* replaces IAS 27 Consolidated and Separate Financial Statements and SIC 12 Consolidation – Special Purpose Entities. IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. Adoption did not result in any change in consolidation status, as the Company does not have subsidiaries or investees.

(ii) *IFRS 11 Joint Arrangements* requires a company to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the company will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures, and SIC-13 Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has analyzed its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

(iii) *IFRS 12 Disclosure of Interest in Other Entities* replaces the disclosure requirements previously included in IAS 27, IAS 31, and IAS 28 Investments in Associates. It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The Company assessed its interests in other entities on January 1, 2013 and determined that no additional disclosure was necessary.

(iv) *IFRS 13 Fair Value Measurement* is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013. The Company has complied with the new disclosure requirements of IFRS 13 in Note 5 – Financial Instruments, as applicable to interim financial statements in accordance with IAS 34.

(v) *IAS 36 Impairment of Assets* was amended in May 2013, effective retrospectively for annual periods beginning on or after January 1, 2014. The amendment removes certain disclosures of the recoverable amount of a CGU containing goodwill, and adds disclosures of the recoverable amount of a CGU with impairment. As allowed by the standard, the Company early adopted the amendment in the current period. Refer to Note 9 for the amended disclosures.

The following standards have been amended but are not yet effective up to the date of issuance of the Company's financial statements. The Company reasonably expects these standards to be effective at a future date and intends to adopt when they become effective:

(vi) IFRS 9 Financial Instruments contains three phases, of which phase one, relating to accounting for financial assets and financial liabilities, and phase 2, relating to hedge accounting, have been published. The third phase will address impairment of financial instruments. For financial assets, IFRS 9 replaces the multiple rules in IAS 39 with a single approach to determine whether a financial asset is measured at amortized cost or fair value. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. IFRS 9 also introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Twin Butte does not currently apply hedge accounting. A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

(vii) IFRS 32 Financial Instruments: Presentation was amended in December 2011 to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 ware effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on Twin Butte.

ASSESSMENT OF BUSINESS RISKS

The following are the primary risks associated with the business of Twin Butte. These risks are similar to those affecting other companies competing in the conventional oil and natural gas sector. Twin Butte's financial position and results of operations are directly impacted by these factors and include:

Operational risk associated with the production of oil and natural gas:

- Reserve risk in respect to the quantity and quality of recoverable reserves;
- Exploration and development risk of being able to add new reserves economically;
- Market risk relating to the availability of transportation systems to move the product to market;
- Commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry; and
- Continued participation of Twin Butte's lenders.

Twin Butte seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a hedging program to hedge commodity prices with creditworthy counterparties;

- Adhering to the Company's safety program and adhering to current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Carrying industry standard insurance;
- Establishing and maintaining adequate resources to fund future abandonment and site restoration costs; and
- Monitoring our joint venture partners' obligations to us and cash calling for capital projects to limit the Company's credit risk.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified under the Canadian securities law.

Twin Butte's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, that the disclosure controls and procedures as of December 31, 2013 are effective and provide reasonable assurance that material information related to the Company is made known to them by others within Twin Butte.

Twin Butte's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal controls over financial reporting ("ICFR"). They have, as at December 31, 2013, designed ICFR or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Twin Butte's officers used to design the ICFR is the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations.

Twin Butte's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting that occurred during our most recent reporting period that has materially affected, or is reasonably likely to affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including Twin Butte's disclosure and internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

MANAGEMENT'S REPORT

To the Shareholders of Twin Butte Energy Ltd.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying financial statements of Twin Butte Energy Ltd. and all of the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those methods it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management has established systems of internal controls, which are designed to provide reasonable assurance the Company's assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information. Internal control systems, no matter how well designed have inherent limitations. Therefore, even those systems that have been determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. It exercises its responsibilities primarily through the Audit Committee, which is comprised of independent, non-management directors. The Audit Committee has reviewed the financial statements with both management and the auditors. This has been reported to the Board of Directors which has approved the financial statements.

The financial statements have been audited by PricewaterhouseCoopers LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

Jim Saunders
Chief Executive Officer

R. Alan Steele
Vice-President, Finance & CFO

March 20, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Twin Butte Energy Ltd.:

We have audited the accompanying financial statements of Twin Butte Energy Ltd., which comprise the balance sheets as at December 31, 2013 and 2012 and the statements of income (loss) and comprehensive income (loss), changes in shareholders' equity, and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the financial position of Twin Butte Energy Ltd. as at December 31, 2013 and 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

March 20, 2014

BALANCE SHEET

(Cdn$ thousands)	Note	Dec 31, 2013	Dec 31, 2012
ASSETS			
Current Assets			
Accounts receivable	20	$ 48,674	$ 42,497
Deposits and prepaid expenses		5,588	4,233
Derivative assets	5	2,228	32,022
		56,490	78,752
Non-current assets			
Derivative assets	5	518	–
Exploration and evaluation	8	64,025	65,779
Property and equipment	9	1,044,605	669,328
Goodwill	10	–	31,402
		$ 1,165,638	$ 845,261
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities	21	$ 80,556	$ 60,822
Dividend payable		5,489	3,350
Derivative liabilities	5	34,983	2,821
		121,028	66,993
Non-current liabilities			
Derivative liabilities	5	–	1,994
Bank indebtedness	11	252,181	184,261
Convertible debentures	12	77,648	–
Deferred taxes	19	31,348	31,521
Decommissioning provision	13	181,758	88,991
		663,963	373,760
Shareholders' Equity			
Share capital	14	717,246	523,226
Contributed surplus		8,818	7,624
Equity component of convertible debenture	12	2,879	–
Deficit		(227,268)	(59,349)
		501,675	471,501
		$ 1,165,638	$ 845,261

Commitments and contingencies (note 23)

The accompanying notes are an integral part of these financial statements.

On Behalf of the Board of Directors:

Jim Saunders
Director

David Fitzpatrick
Director

STATEMENT OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

		Twelve months ended December 31	
(Cdn$ thousands except per share amounts)	*Note*	**2013**	2012
Petroleum and natural gas sales	*15*	**$ 394,588**	$ 304,729
Royalties		**(82,029)**	(64,332)
Revenues		**$ 312,559**	$ 240,397
Expenses			
Operating		**140,124**	99,685
Transportation		**15,659**	13,554
General and administrative	*16*	**12,517**	10,607
Transaction costs	*7*	**2,193**	4,239
Share-based payments	*14*	**4,913**	4,386
Finance expense	*17*	**11,084**	7,302
Loss (gain) on derivatives	*5*	**45,657**	(61,911)
Exploration and evaluation expense	*8*	**14,798**	5,038
Loss (gain) on disposition of property and equipment	*9*	**(2,142)**	(2,997)
Loss (gain) on disposition of exploration asset	*8*	**(3,262)**	–
Negative goodwill		**–**	(1,330)
Depletion and depreciation	*9*	**134,725**	99,471
Impairment of property and equipment	*9*	**49,519**	17,237
Impairment of goodwill	*10*	**31,402**	–
		457,187	195,281
Income (loss) before income taxes		**(144,628)**	45,116
Deferred tax expense (recovery)	*19*	**(28,995)**	13,586
Net income (loss) and comprehensive income (loss)		**$ (115,633)**	$ 31,530
Net income (loss) per share $			
Basic	*14*	**(0.44)**	0.15
Diluted	*14*	**(0.44)**	0.15

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CASH FLOWS

(Cdn$ thousands)	Note	Twelve months ended December 31 2013	2012
Cash provided by (used in):			
OPERATING ACTIVITIES:			
Net income (loss)		**$ (115,633)**	$ 31,530
Adjustments for items not involving cash:			
Depletion and depreciation	*9*	**134,725**	99,471
Impairments	*9*	**80,921**	17,237
Deferred tax expense (recovery)		**(28,995)**	13,586
Unrealized (gain) loss on derivatives	*5*	**41,543**	(32,510)
Finance expenses	*17*	**11,084**	7,302
Interest paid	*17*	**(8,537)**	(5,679)
Share-based payments	*14*	**4,913**	4,386
Exploration and evaluation expenses	*8*	**14,798**	5,038
Gain on disposition of property and equipment	*9*	**(2,142)**	(2,997)
Gain on disposition of exploration asset	*8*	**(3,262)**	–
Negative goodwill		**–**	(1,330)
Cash premiums on derivatives	*5*	**7,943**	–
Expenditures on decommissioning provision	*13*	**(3,287)**	(1,140)
Changes in non-cash working capital	*18*	**(3,333)**	(3,127)
		130,738	131,767
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	*11*	**(12,992)**	29,180
Issuance of convertible debentures	*12*	**81,369**	–
Issuance of share capital	*14*	**66,569**	–
Issuance of share capital on exercise of stock options	*14*	**29**	178
Dividends paid		**(44,591)**	(32,223)
		90,384	(2,865)
INVESTING ACTIVITIES			
Expenditures on corporate and property acquisitions	*7*	**(154,985)**	(91,200)
Expenditures on property and equipment		**(100,934)**	(53,055)
Expenditures on exploration and evaluation assets		**(5,872)**	(4,142)
Proceeds on disposition of property and equipment	*9*	**26,086**	6,386
Proceeds on disposition of exploration and evaluation assets	*8*	**3,545**	483
Changes in non-cash working capital	*18*	**11,038**	12,626
		(221,122)	(128,902)
Change in cash		**$ –**	$ –
Cash and cash equivalents, beginning and end of period		**$ –**	$ –

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

		Twelve months ended December 31	
(Cdn$ thousands)	*Note*	**2013**	2012
Share capital			
Balance, beginning of period		**$ 523,226**	$ 227,520
Common shares issued for Black Shire acquisition	*7*	**$ 116,126**	$ –
Common shares issued for Emerge acquisition		**–**	134,264
Common shares issued for Avalon acquisition		**–**	65,314
Common shares issued for Waseca acquisition		**–**	88,159
Common shares issued pursuant to subscription receipts	*14*	**70,001**	–
Share issue costs, net of deferred tax	*14*	**(2,574)**	–
Common shares issued pursuant to the DRIP and SDP	*14*	**5,556**	1,676
Common shares issued under employee and option plan	*14*	**4,911**	6,293
Balance, end of period		**$ 717,246**	$ 523,226
Contributed surplus			
Balance, beginning of period		**$ 7,624**	$ 7,506
Share-based payments for awards exercised	*14*	**(4,882)**	(6,757)
Share-based payments for awards granted		**6,076**	6,875
Balance, end of period		**$ 8,818**	$ 7,624
Deficit			
Balance, beginning of period		**$ (59,349)**	$ (53,630)
Dividends	*14*	**$ (52,286)**	$ (37,249)
Net income (loss) and comprehensive income (loss)		**(115,633)**	31,530
Balance, end of period		**$ (227,268)**	$ (59,349)

The accompanying notes are an integral part of these financial statements.

For the years ended December 31, 2013 and 2012

All tabular amounts are in thousands of Canadian dollars except as otherwise indicated.

NOTE 1. BUSINESS AND STRUCTURE OF TWIN BUTTE

Twin Butte Energy Ltd. ("Twin Butte" or "the Company") is a dividend paying oil and natural gas exploration, development and production company with properties located in Western Canada. Twin Butte is domiciled and incorporated in Canada under the Business Corporations Act (Alberta). Twin Butte's head office address is 410, 396 – 11th Avenue SW, Calgary, Alberta, Canada. The Company's primary listing is on the Toronto Stock Exchange under the symbol "TBE".

NOTE 2. BASIS OF PRESENTATION

The Company prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company has consistently applied the same accounting policies throughout all years presented in these financial statements, except as identified in note 3(s).

These financial statements have been prepared on the historical cost basis, except as disclosed in the significant accounting policies in Note 3. They are presented in Canadian dollars, which is the Company's functional currency.

These financial statements were approved and authorized for issue by the Board of Directors on March 20, 2014.

NOTE 3. SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used in the preparation of these financial statements are as follows:

(a) Cash and cash equivalents

Cash consists of balances held with banks, and other short-term highly liquid investments with original maturities of three months or less from inception.

(b) Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Gains and or losses on these items are included in the statement of income (loss).

(c) Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have been expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized when the obligation specified in the contract is discharged, cancelled or expires.

All financial instruments are initially recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, are based on how each financial instrument was initially classified. The Company has classified each identified financial instrument into the following categories: fair value through profit or loss, loans and receivables, held-to-maturity investments, available for sale financial assets, and financial liabilities at amortized cost. Fair value through profit or loss financial instruments are measured at fair value with gains and losses recognized in income immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to income when the asset is derecognized. Loans and receivables, held-to-maturity investments and financial liabilities at amortized cost are recognized at amortized cost using the effective interest method and impairment losses are recorded in income when incurred.

The Company's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the conversion feature. As the debentures are converted, a portion of debt and conversion feature components are transferred to share capital. The debt component associated with the convertible debentures is designated as a financial liability at amortized cost.

Derivative instruments executed by the Company to manage market risk associated with volatile commodity prices are classified as held for trading within fair value through profit or loss and recorded on the balance sheet at fair value as derivative assets and liabilities. Gains and losses on these derivative instruments are recorded as gains and losses in the statement of income (loss) in the period they occur.

Gains and losses on derivative instruments are comprised of cash receipts and payments associated with periodic settlement that occurs over the life of the instrument (realized gains/losses), and non-cash gains and losses associated with changes in the fair values of the instruments which are remeasured at each reporting date and recorded on the balance sheet (unrealized gains/losses). Transaction costs attributed to the acquisition or issue of a derivative instrument are expensed immediately. For other financial instruments, transaction costs are added to the fair value initially recognized for a financial asset or liability.

(d) Share capital

Equity instruments issued by the Company are recorded at the proceeds received, with direct issue costs as a deduction there from, net of any associated tax benefit.

(e) Joint arrangements

A portion of the Company's oil and natural gas activities involve joint arrangements classified as joint operations. The Company's share of these joint operations and a proportionate share of the relevant revenue and costs are reflected in the financial statements. Joint control exists for contractual arrangements governing Twin Butte's assets where all partners collectively control the arrangement and share the associated risks, Twin Butte has less than 100 percent working interest, all of the partners have control of the arrangement collectively and spending on the project requires unanimous consent of all parties. Twin Butte does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

(f) Property and equipment and exploration and evaluation assets

(i) Exploration and evaluation (E&E) expenditures

Pre-license costs are recognized in the statement of income (loss) as incurred. All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. Such costs can typically include costs to acquire land rights in areas with no proved or probable reserves assigned, geological and geophysical costs, and exploration wells.

Exploration and evaluation costs initially are capitalized as either tangible or intangible according to the nature of the assets acquired. The costs are accumulated in areas by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are not depreciated, and are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. If an impairment indicator for E&E assets is noted, for purposes of impairment testing, exploration and evaluation assets are allocated cash-generating units.

The technical feasibility and commercial viability of extracting a mineral resource from exploration and evaluation assets is considered when proved and probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and probable reserves have been discovered. Upon determination of proved and probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to development and production assets within property and equipment. If the well or exploration project did not encounter potentially economic oil and gas quantities, the unrecoverable costs are expensed and reported in exploration and evaluation expense in the period incurred.

(ii) Development and production expenditures

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Costs include E&E expenditures incurred in finding commercial reserves transferred from E&E assets, drilling and completion, production facilities, decommissioning costs, geological and geophysical costs and directly attributable costs related to development and production activities, net of any government incentive programs, and for qualifying assets, borrowing costs The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant parts of an item of property and equipment, including oil and natural gas properties, have different useful lives, they are accounted for as separate items (major components). Gains and losses on disposal of an item of property and equipment, including oil and natural gas properties and E&E assets, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized within the statement of income (loss).

(iii) Subsequent costs

Costs incurred subsequent to commencement of production that are significant are recognized as oil and gas assets only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized in income as incurred.

(iv) Depletion and depreciation

The net carrying value of oil and gas properties is depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually. Major development projects are not depleted until production commences.

The Company records furniture and equipment at cost and provides depreciation on the declining balance method at a rate of 20% per annum which is designed to amortize the cost of the assets over their estimated useful lives. The Company records leasehold improvements at cost and provides depreciation on the straight-line method over the term of the lease. Leased assets are depreciated over the shorter of the lease term and their useful lives. Depreciation methods, useful lives and residual values are reviewed at each financial year end, and, if necessary, changes in useful lives are accounted for prospectively.

(g) Asset swaps

Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the amount given up. Any gain or loss on derecognition of the asset given up is recognized in statement of income (loss). For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at carrying value.

(h) Leased assets

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under the operating leases are charged to income on a straight-line basis over the period of the lease.

(i) Impairment

(i) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income in the period incurred. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the statement of income (loss).

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less cost of disposal.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less cost of disposal is assessed utilizing market valuation based on an arm's length transaction between active participants. In the absence of any such transactions, fair value less costs of disposal is estimated by discounting the expected after-tax cash flows of the cash generating unit at an after-tax discount rate that reflects the risk of the properties in the cash generating unit. The discounted cash flow calculation is then increased by a tax-shield calculation, which is an estimate of the amount that a prospective buyer of the cash generating unit would be entitled. The carrying value of the cash generating unit is reduced by the deferred tax liability associated with its property and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been objective change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized.

(j) Share based payments

The Company's compensation program currently consists of three primary components: (i) annual base salary (ii) discretionary short-term incentive cash bonus; (iii) and periodic grants of long-term incentives in the form of share awards ('equity-settled transactions'). Share awards are granted from time to time to participants at varying levels consistent with the individual's position and level of responsibility.

The Company follows the fair value method of valuing share award grants. Under this method, compensation costs attributable to share options granted to employees, officers and directors of the Company are measured at fair value at the date of grant determined in reference to the Company's share price on the grant date, and the resulting share-based payment expense is recognized on a graded-vesting basis over the related vesting period with a corresponding increase to contributed surplus.

Certain share awards have been granted with a performance multiplier. This multiplier, ranging from zero to two, will be applied at exercise and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period and the board of directors' discretion. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the exercise of the share awards, consideration paid together with the amount in contributed surplus is recorded as an increase to share capital.

(k) Decommissioning provision

A decommissioning liability is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Decommissioning liabilities are determined by discounting the expected future cash flows at a risk-free rate. A corresponding asset equal to the initial estimated liability is capitalized as part of the long-lived asset. The increase in the provision due to the passage of time is recognized as a finance cost in the statement of income (loss). Actual expenditures incurred are charged against the accumulated liability. Revisions to the estimated amount and timing of the obligations are reflected as increases or decreases to the decommissioning liability.

(l) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party, sales prices and costs can be reasonably measured, and it is probable that future economic benefits will flow to the entity. For natural gas, this is generally at the time product enters the pipeline. For crude oil, this is generally at the time the product reaches a trucking terminal or pipeline. For natural gas liquids, this is generally at the time the product is processed through a gas plant. Revenue is measured net of discounts, customs duties and royalties.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(m) Finance expense

Finance expense comprises interest expense on borrowings, interest on convertible debentures, accretion of the discount on convertible debentures and accretion of the discount on the decommissioning provision.

(n) Borrowing costs

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. The Company considers a qualifying asset to be any significant construction project expected to take more than twelve months to complete. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding general and specific borrowings during the period.

(o) Income tax

Income tax expense comprises current and deferred income tax. Income tax expense is recognized in the statement of income (loss) except to the extent that it relates to items recognized directly in shareholders' equity.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to income tax payable in respect of previous years. Deferred income tax is recognized using the liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred income tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are only offset when they arise within the same tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

(p) Net income (loss) per share

Basic net income (loss) per share is calculated by dividing the net income (loss) of the Company by the weighted average number of common shares outstanding during the period. Diluted net income (loss) per share is determined by adjusting the net income (loss) attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

(q) Dividends

Dividends are accrued when declared by the Board of Directors.

(r) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net income as negative goodwill.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

(s) New standards and interpretations not yet adopted

The Company has adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2013. These changes were made in accordance with the applicable transitional provisions.

(i) IFRS 10 Consolidated Financial Statements replaces IAS 27 Consolidated and Separate Financial Statements and SIC 12 Consolidation – Special Purpose Entities. IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. Adoption did not result in any change in consolidation status, as the Company does not have subsidiaries or investees.

(ii) IFRS 11 Joint Arrangements requires a company to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the company will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures, and SIC-13 Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has analyzed its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

(iii) IFRS 12 Disclosure of Interest in Other Entities replaces the disclosure requirements previously included in IAS 27, IAS 31, and IAS 28 Investments in Associates. It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The Company assessed its interests in other entities on January 1, 2013 and determined that no additional disclosure was necessary.

(iv) IFRS 13 Fair Value Measurement is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013. The Company has complied with the new disclosure requirements of IFRS 13 in Note 5 – Financial Instruments, as applicable to interim financial statements in accordance with IAS 34.

(v) *IAS 36 Impairment of Assets* was amended in May 2013, effective retrospectively for annual periods beginning on or after January 1, 2014. The amendment removes certain disclosures of the recoverable amount of a CGU containing goodwill, and adds disclosures of the recoverable amount of a CGU with impairment. As allowed by the standard, the Company early adopted the amendment in the current period. Refer to Note 9 for the amended disclosures.

The following are standards issued but not yet effective up to the date of issuance of these financial statements. The Company reasonably expects these standards to be applicable at a future time and intends to adopt these standards when they become effective.

(i) *IFRS 9 Financial Instruments* contains three phases, of which phase one, relating to accounting for financial assets and financial liabilities, and phase two, relating to hedge accounting, have been published. The third phase will address impairment of financial instruments. For financial assets, IFRS 9 replaces the multiple rules in IAS 39 with a single approach to determine whether a financial asset is measured at amortized cost or fair value. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. IFRS 9 also introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Twin Butte does not currently apply hedge accounting. A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

(ii) *IFRS 32 Financial Instruments: Presentation* was amended in December 2011 to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 were effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on Twin Butte.

NOTE 4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 9 – valuation of property and equipment;
- Note 13 – measurement of decommissioning provision;
- Note 14 – measurement of share-based compensation; and
- Note 19 – income tax expense.

Judgements

In the process of applying the Company's accounting policies, management has made the following judgements, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the financial statements.

(a) Exploration and evaluation assets

The decision to transfer assets from exploration and evaluation to property and equipment is based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability (Note 8).

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporate the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs (Note 9).

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is highly likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

(c) Depletion of oil and gas assets

Oil and gas properties are depleted using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depletion could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves (Note 9).

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Company, and grouped the properties into cash generating units on the basis of their ability to generate independent cash inflows, similar reserve characteristics, geographical location, and shared infrastructure (Note 9).

(e) Impairment indicators and calculation of impairment

At each reporting date, Twin Butte assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property and equipment are not recoverable, or impaired. Such circumstances include incidents of deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves. At December 31, 2013, Management exercised judgement at determined that there were impairment indicators present for certain CGUs (Note 9). When management judges that circumstances clearly indicate impairment, property and equipment and exploration and evaluation assets are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value in use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions that are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates, as well as future development and operating costs (Note 9).

NOTE 5. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness, convertible debentures, dividends payable, and derivative assets and liabilities. As at December 31, 2013, the carrying amounts reported on the Balance Sheet approximated the estimated fair values of financial instruments (excluding convertible debentures) due to the short terms to maturity and the floating interest rate on the bank indebtedness. The estimated fair value of the convertible debentures has been determined based on prices sourced from market data and other observable inputs, as discussed below.

($000's)	Level in fair value hierarchy	As at December 31, 2013		As at December 31, 2012	
		Carrying Amount	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Financial Assets					
Held For trading					
Derivative assets – oil and gas	Level 2	**2,745**	**2,745**	32,022	32,022
Derivative assets – power	Level 3	**1**	**1**	–	–
Loans and receivables					
Accounts receivable	Level 2	**48,674**	**48,674**	42,497	42,497
Deposits	Level 2	**502**	**502**	744	744
Financial Liabilities					
Held for trading					
Derivative liabilities – oil and gas	Level 2	**34,983**	**34,983**	4,815	4,815
Financial Liabilities at amortized cost					
Accounts payable and accrued liabilities	Level 2	**80,556**	**80,556**	60,822	60,822
Dividends payable	Level 2	**5,489**	**5,489**	3,350	3,350
Bank indebtedness	Level 2	**252,181**	**252,181**	184,261	184,261
Convertible debentures	Level 2	**77,648**	**77,648**	–	–

Fair value is determined following a three level hierarchy:

Level 1: Quoted prices in active markets for identical assets and liabilities. The Company does not have any financial assets or liabilities that require level 1 inputs.

Level 2: Inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly. Such inputs can be corroborated with other observable inputs for substantially the complete term of the contract. Twin Butte uses Level 2 inputs in the determination of the fair value of oil and gas derivative assets and liabilities, and convertible debentures.

Level 3: Fair value is determined using inputs that are not observable. Twin Butte uses Level 3 inputs in the determination of the fair value of power purchase derivative assets and liabilities, and the fair value less costs of disposal used in determining the recoverable amount of a Cash Generating Unit (CGU) for the purpose of impairment testing.

Derivative assets and liabilities are carried at fair value and are measured on a recurring basis. The fair values of oil and gas commodity derivatives are determined using a Level 2 valuation model and inputs include quoted forward prices for commodities, foreign exchange rates, volatility and discounting, all of which can be observed or corroborated in the marketplace. Power purchase derivatives are calculated using a Level 3 valuation model, as inputs include forward power prices in less active markets. These inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness.

The fair value of convertible debentures is determined using a Level 2 valuation model and inputs include quoted market prices for the debentures, interest rates and discounting. In testing for impairment of property and equipment, a Level 3 valuation model is used to determine the recoverable amount of a CGU. The fair value less costs of disposal model used contains inputs that are not readily observable or corroborated, such as forecasted cash flows over the estimated life of reserves.

The Company's policy is to recognize transfers into and out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. During the year ended December 31, 2013, there were no transfers between levels 1, 2 or 3.

The table below summarizes the changes in Level 3 measured derivatives:

($000's)	Twelve months ended December 31, 2013
Level 3, December 31, 2012	–
Power purchase derivatives	1
Level 3, December 31, 2013	1

(a) Risk Management Assets and Liabilities

The table below summarizes the realized and unrealized gain (loss) on derivatives:

	Twelve months ended December 31	
	2013	2012
Realized gain (loss)	**(4,114)**	29,401
Unrealized gain (loss)	**(41,543)**	32,510
Gain (loss) on derivatives	**(45,657)**	61,911

During the year ended December 31, 2013, the Company also realized $7.9 million of cash premiums received for selling crude oil swaption derivative contracts (December 31, 2012 – $nil). A crude oil swaption contract is an option that allows the holder to exercise and enter into a fixed price crude oil derivative contract.

Derivative Position

As at	**Dec 31, 2013**	Dec 31, 2012
Current asset	**2,228**	32,022
Non-current asset	**518**	–
Current liability	**(34,983)**	(2,821)
Non-current liability	**–**	(1,994)
Net derivative asset (liability) position	**(32,237)**	27,207

Derivative Summary

As at	**Dec 31, 2013**	Dec 31, 2012
Crude oil sales price derivatives	**(31,707)**	22,915
Natural gas sales price derivatives	**(531)**	4,292
Power purchase price derivatives	**1**	–
Net derivative asset (liability) position	**(32,237)**	27,207

Crude Oil Sales Price Derivatives

Daily barrel (bbl) quantity	Term of contract	WTI (1) Fixed price per bbl ($CAD)	WCS (2) Fixed Price per bbl ($CAD)	Fixed price per bbl WCS (2) vs. WTI (1) ($CAD)	Fixed written call price per bbl WTI (1) ($USD)	Fair market value *$000's*
3,500	January 1, 2014 to December 31, 2014	$ 95.89				(7,892)
12,400	January 1, 2014 to June 30, 2014	$ 96.21				(17,713)
8,650	July 1, 2014 to September 30, 2014	$ 94.69				(5,110)
500	July 1, 2014 to December 31, 2014	$ 99.25				(78)
7,500	October 1, 2014 to December 31, 2014	$ 94.66				(3,033)
1,000	January 1, 2015 to March 31, 2015	$ 97.46				37
1,500	October 1, 2014 to December 31, 2014		$ 75.00			(224)
1,000	January 1, 2014 to December 31, 2014			(22.00)		444
2,000	January 1, 2014 to June 30, 2014			(19.55)		1,783
4,000	July 1, 2014 to December 31, 2014			(21.90)		(140)
2,000	July 1, 2014 to September 30, 2014			(21.95)		(57)
1,000	January 1, 2015 to December 31, 2015			(19.75)		481
1,300	January 1, 2014 to December 31, 2014				$ 110.00	(205)
Crude oil fair value position						(31,707)

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Natural Gas Sales Price Derivatives

Daily giga-joule (GJ) quantity	Term of contract	Fixed price per GJ AECO Daily	Fair Market Value *$000's*
8,000	January 1, 2014 to December 31, 2014	$3.53	(531)
Natural gas fair value position			(531)

Power Purchase Price Derivatives

Daily Megawatt (MW) hours quantity	Term of contract	Fixed price per MW	Fair Market Value *$000's*
288	January 1, 2014 to December 31, 2014	$55.05	49
192	January 1, 2015 to December 31, 2015	$53.02	(48)
Power purchase contract fair value position			1

(b) Risks Associated with Financial Assets and Liabilities

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as: credit risk; liquidity risk; price and currency risk; and interest rate risk.

Price and currency risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. Twin Butte monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices and foreign exchange rates. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Twin Butte. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its heavy and medium crude oil sales. This includes swaps to help protect against widening light/heavy crude oil price differentials. When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2013, a 10% increase would decrease net income for the year ended December 31, 2013 by $42.7 million, while a 10% decrease would increase net income for the year ended December 31, 2012 by $42.7 million.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the AECO price. When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2013, a 10% increase would decrease net income for the year ended December 31, 2013 by $1.1 million, while a 10% decrease would increase net income for the year ended December 31, 2013 by $1.1 million.

Currency – North American oil and natural gas prices are based upon US dollar denominated commodity prices. As a result, although receivables are denominated in Canadian dollars, the price received by Canadian producers is affected by the Cdn$/US$ foreign exchange rate that may fluctuate over time. To minimize this risk, fixed price swaps for crude oil and natural gas are denominated in Canadian dollars.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk is as follows:

$000's	**Dec 31, 2013**	Dec 31, 2012
Accounts receivable	**48,674**	42,497
Deposits	**502**	744
Derivative assets	**2,746**	32,022
	51,922	75,263

Accounts receivable, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect management's assessment of the associated maximum exposure to such credit risk. Substantially all of the Company's accounts receivables are due from customers and partners concentrated in the Canadian oil and gas industry. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic conditions. Management aims to mitigate this risk by dealing with a broad selection of reputable partners within the sector, by reviewing credit ratings of counterparties and partners, and through closely monitoring significant balances. When necessary, the Company requires cash calls from its partners on capital projects before they commence, and with certain counterparties, has the ability to withhold production or offset payables.

Receivables related to the sale of the Company's petroleum and natural gas production are normally collected on the 25th day of the month following delivery. As at December 31, 2013, $1.9 million or 3.9% of accounts receivable are outstanding for 90 days or more (December 31, 2012, $2.0 million or 4.8% of accounts receivables). The Company has provided an allowance for doubtful accounts of $0.8 million at December 31, 2012 (December 31, 2012 – $0.7 million) and believes that the remaining accounts receivable balance, net of this allowance, is collectible.

The Company's deposits are primarily due from the Alberta Provincial government and are viewed by Management as having minimal credit risk. To the extent that Twin Butte enters into derivatives to manage commodity price risk, the Company is exposed to credit risk associated with counterparties. The Company enters into derivative contracts with major national and investment banks to mitigate this credit risk.

Liquidity risk

Liquidity risk is the risk that Twin Butte will not be able to meet all of its financial obligations when they become due. The Company manages its liquidity risk through the active management of cash flows, debt and maintaining appropriate access to credit. Twin Butte believes it has the ability to satisfy current obligations with cash provided by operating activities and where necessary, utilization of the available portion of the existing credit facility for short-term fluctuations. For longer term management, the Company considers debt and share issuances under appropriate circumstances.

The timing of cash outflows relating to financial liabilities as at December 31, 2013 are as follows:

December 31, 2013	Less than one year	One to three years	Three to five years	Thereafter	Total
Trade and accrued liabilities	80,556	–	–	–	80,556
Derivative liability	34,983	–	–	–	34,983
Bank indebtedness – principal	–	252,181	–	–	252,181
Bank indebtedness – interest	10,087	3,362	–	–	13,449
Convertible debenture – principal	–	–	85,000	–	85,000
Convertible debenture – coupon	5,312	10,625	10,625	–	26,562
Dividend payable	5,489	–	–	–	5,489
Total	136,427	266,168	95,625	–	498,220

To the extent that Twin Butte enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. Derivative instruments are not entered for speculative purposes and management closely monitors commodity risk exposure in comparison to forecasted sales volumes. Liquidity risk is partially mitigated as losses realized due to high commodity prices are generally matched by increased cash flows from sales in the high commodity price environment.

The Company's bank indebtedness (Note 11) is drawn on a revolving credit facility of $400 million, renewable annually at the option of the syndicate. If not extended, the credit facility is converted into a one-year facility with the principal payable at the end of the one-year term. The facility is also subject to an annual borrowing base review performed by the banking syndicate, based primarily on reserves, commodity prices, and other factors estimated by the lenders. A decrease to the borrowing base could lead to a reduction in the credit facility and require repayment. The facility was last renewed in May 2013 and management fully expects that the facility will be extended at each annual review.

In 2013, the Company issued convertible debentures with a face value of $85 million, convertible into shares of Twin Butte at the holder's option. If not already redeemed or converted at either the holder or the Company's option, on December 31, 2018 the Company will redeem remaining debentures up to the maximum face value of $85 million.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank indebtedness fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been 1 percent higher throughout the year ended December 31, 2013, net income would have decreased by $2.2 million (December 31, 2012 – $1.5 million) based on the average debt balance outstanding during the period.

NOTE 6. CAPITAL MANAGEMENT

The Company's capital structure is comprised of shareholder's equity and the non-GAAP measure of total net debt (2). Twin Butte's capital structure as at December 31, 2013 and December 31, 2012 is as follows:

	Dec 31, 2013	Dec 31, 2012
Bank indebtedness	**252,181**	184,261
Convertible debentures	**77,648**	–
Working capital deficit (surplus) (1)	**31,783**	17,442
Net debt (2)	**361,612**	201,703
Shareholders' Equity	**501,675**	471,501
Net Debt to Equity (2)	**0.72**	0.43

(1) Working capital deficit (surplus) is a non-GAAP measure that includes accounts receivables, deposits and prepaid expenses, accounts payable, and accrued liabilities, and dividend payable.

(2) Net debt and net debt to equity are non-GAAP measures. Net debt is defined as the total of bank indebtedness, convertible debenture liability, accounts payable and accrued liabilities, cash dividend payable, less accounts receivable, deposits and prepaids, whereas net debt to equity is the ratio of net debt compared to equity.

As at December 31, 2013, the Company utilized $252.2 million of its dedicated $400 million credit facility. The bank debt, working capital deficit of $31.8 million and convertible debenture liability of $77.6 million resulted in $361.6 million of net debt (December 31, 2012 – $201.7 million). The increase in debt increased the net debt to equity ratio from 0.43 at December 31, 2012 to 0.72 at December 31, 2013.

The Company's objective when managing capital is to maintain a conservative, yet flexible structure which will allow it to execute on its capital investment program and provide stability to dividends. The Company actively monitors its capital structure through cash flow from operating activities (before changes in non-cash working capital, which drives current and forecasted net debt levels. In forecasting these amounts, the Company includes economic conditions; investment opportunities; past and forecasted capital investment efficiencies; and current and forecasted petroleum and natural gas prices.

In order to manage the capital structure, the Company will focus on its forecasted debt to forecasted cash flow from operating activities (before changes in non-cash working capital) ratio; the current level of available credit under the bank facility; the level of bank credit that may be obtainable as a result of crude oil and natural gas reserve growth; the availability of other sources of debt; issuing new common equity if available on favorable terms; the sale of assets; and limiting the size of the investment program.

The Company's share capital is not subject to external restrictions; however, its credit facility value is based primarily on its petroleum and natural gas reserves and there are covenants Twin Butte must comply with (Note 11). The Company was in compliance with all of its financial covenants at the end of the reporting period.

NOTE 7. BUSINESS COMBINATION

(a) Acquisition of Black Shire Energy Inc.

On November 5, 2013, Twin Butte completed the business combination with Black Shire Energy Inc. ("Black Shire"), which provides for the acquisition by Twin Butte of all the issued and outstanding common shares of Black Shire on the basis of 0.697 common shares (54,012,276 issued) of Twin Butte for each Black Shire share plus cash of $155 million, for total consideration of $271 million. The value of the Common Shares issued as consideration was determined based on the trading value of Twin Butte's Common Shares on the date of acquisition. The purpose of the acquisition was to increase Twin Butte's presence and size in medium density oil, while also allowing for operating synergies. Black Shire was amalgamated with Twin Butte following the completion of the acquisition and the transaction was accounted for as a business combination using the acquisition method of accounting under IFRS 3 Business Combinations.

The following are the estimated fair values of the net assets of Black Shire:

		Total
Petroleum and natural gas properties		422,644
Exploration and evaluation assets		10,085
Net working capital		(85,410)
Derivative liability		(9,957)
Deferred income tax liability		(28,777)
Decommissioning obligation		(37,474)
Total net assets acquired	$	271,111

The net working capital asset consists of the following:

		Total
Accounts receivable		17,405
Deposits and prepaid expenses		289
Accounts payable and accrued liabilities		(22,192)
Debt		(80,912)
Net working capital	$	(85,410)

Consideration		Total
Common Shares (54,012,276 shares at $2.15 per share)		116,126
Cash		154,985
	$	271,111

The recognized identifiable assets and liabilities assumed were based on best estimates by Twin Butte's management and were based on valuations prepared by external engineers. The consideration paid is equal to the fair value of net assets acquired. The decommissioning obligation was fair valued using the credit–adjusted rate of 6%. The accounting for the business combination remains subject to further refinement as additional cost estimates and tax balances are finalized.

The transaction costs related to the acquisition amounted to $2.2 million and were expensed in the statement of income (loss) and comprehensive income (loss). In the period from November 5, 2013 to December 31, 2013, the acquisition contributed revenues of $26.7 million and net earnings of $4.2 million which are included in the statement of income (loss) and comprehensive income (loss). Management estimates that Twin Butte's revenue would have increased by $187.5 million and net earnings would have increased by $61.6 million, had this transaction been completed on January 1, 2013. This pro-forma information would not necessarily be indicative of results had the acquisition occurred on January 1, 2013.

(b) Acquisition of Emerge Oil & Gas Inc.

If all of the business combinations completed in 2012 had occurred on January 1, 2012, Management estimates that Twin Butte's revenue would have increased by $92.2 million and net earnings would have increased by $4.9 million. This pro-forma information would not necessarily be indicative of results had the acquisitions occurred on January 1, 2012.

On January 10, 2012, the Company purchased all the issued and outstanding shares of Emerge Oil & Gas Inc. ("Emerge"), a public exploration and production company, for total consideration of $134 million. Emerge was amalgamated with Twin Butte on the same day. The purpose of the acquisition was to increase Twin Butte's presence and size in its core heavy oil fairway allowing for operating synergies. The value of the Common Shares issued as consideration was determined based on the trading value of Twin Butte's Common Shares on the date of acquisition. The purchase was paid for through the issuance of 54.1 million common shares of Twin Butte and was accounted for as a business combination using the acquisition method of accounting under IFRS 3 Business Combinations.

The following are the estimated fair values of the net assets of Emerge:

		Total
Petroleum and natural gas properties	$	203,000
Exploration and evaluation assets		3,627
Deferred income tax asset		12,067
Net working capital		(60,028)
Decommissioning obligation		(23,072)
Negative goodwill		(1,330)
Total net assets acquired	$	134,264

The net working capital consists of the following:

		Total
Accounts receivable	$	17,369
Deposits and prepaid expenses		534
Accounts payable and accrued liabilities		(18,371)
Derivative liabilities		(1,232)
Bank indebtedness		(58,328)
Net working capital	$	(60,028)

Consideration		Total
Common Shares (54,138,883 shares at $2.48 per share)	$	134,264

The recognized amounts of identifiable assets and liabilities assumed are best estimates by Twin Butte's management and are based on valuations prepared by external engineers. Subsequent to the initial accounting of this business combination, the amount recorded for the deferred income tax asset was reduced, therefore decreasing the initial bargain purchase gain. The adjusted fair value of net assets acquired exceeded the consideration and a bargain purchase of $1.3 million was included in net income (loss) during the year ended December 31, 2012. The fair value of property and natural gas properties over the total consideration paid gave rise to the gain on purchase. The decommissioning obligation was fair valued using the credit–adjusted rate of 6%.

The transaction costs related to the acquisition amounted to $2.2 million and were expensed in the statement of income (loss) and comprehensive income (loss). In the period from January 10, 2012 to December 31, 2012, the acquisition contributed revenues of $128.5 million and net earnings of $10.4 million which are included in the statement of income (loss) and comprehensive income (loss).

(c) Swimming Asset Acquisition

On April 1, 2012, Twin Butte completed the acquisition of assets in the Swimming area for cash consideration of $14.1 million. This property acquisition was recognized as a business combination in accordance with IFRS 3 Business Combinations, as the assets acquired met the definition of a business. The acquisition has been accounted for using the acquisition method, and the recognized amounts of identifiable asset acquired and liabilities assumed at fair value are as follows: $13.5 million of Petroleum and natural gas properties, $1.3 million of E&E assets, and $0.7 million in decommissioning obligation. The asset was acquired with full tax pools and no working capital items.

The transaction costs related to the acquisition amounted to $0.1 million and were expensed in the statement of income (loss) and comprehensive income (loss). In the period from April 1, 2012 to December 31, 2012, the acquisition contributed revenues of $5.4 million and net earnings of $1 million which are included in the statement of income (loss) and comprehensive income (loss).

(d) Acquisition of Avalon Exploration Ltd.

On August 29, 2012, the Company purchased all the issued and outstanding shares of Avalon Exploration Ltd. ("Avalon"), a private exploration and production company, for total consideration of $65.3 million. Avalon was amalgamated with Twin Butte on the same day. The purpose of the acquisition was to increase Twin Butte's presence and size in its core heavy oil fairway allowing for operating synergies. The value of the Common Shares issued as consideration was determined based on the trading value of Twin Butte's Common Shares on the date of acquisition. The purchase was paid for through the issuance of 24.6 million common shares of Twin Butte and was accounted for as a business combination using the acquisition method of accounting under IFRS 3 Business Combinations.

The following are the estimated fair values of the net assets of Avalon:

		Total
Petroleum and natural gas properties	$	68,000
Exploration and evaluation assets		30,247
Deferred income tax liability		(9,459)
Net working capital		(33,814)
Decommissioning obligation		(4,979)
Goodwill		15,319
Total net assets acquired	$	65,314

The net working capital consists of the following:

		Total
Accounts receivable	$	3,670
Deposits and prepaid expenses		267
Accounts payable and accrued liabilities		(6,419)
Bank indebtedness		(31,332)
Net working capital	$	(33,814)

Consideration		Total
Common Shares (24,554,027 shares at $2.66 per share)	$	65,314

The recognized amounts of identifiable assets and liabilities assumed are best estimates by Twin Butte's management. Subsequent to the initial accounting of this business combination, estimates were revised to be based principally on valuations prepared by external engineers, resulting in a decrease in the fair value of the petroleum and natural gas properties. The consideration paid exceeded the fair value of net assets acquired and goodwill was recognized in the amount of $15.3 million. A portion of this goodwill relates to the increase in Twin Butte's share price from the initial valuation date, to the close of the transaction. The decommissioning obligation was fair valued using the credit–adjusted rate of 6%. The accounting for the business combination remains subject to further refinement as additional cost estimates and tax balances are finalized.

The transaction costs related to the acquisition amounted to $0.8 million and were expensed in the statement of income (loss) and comprehensive income (loss). In the period from August 29, 2012 to December 31, 2012, the acquisition contributed revenues of $13.0 million and net earnings of $1.3 million, which are included in the statement of income (loss) and comprehensive income (loss).

(e) Auburndale Asset Acquisition

On October 4, 2012, Twin Butte completed the acquisition of assets in the Auburndale area for cash consideration of $20.4 million. This property acquisition was recognized as a business combination in accordance with IFRS 3 Business Combinations, as the asset met the definition of a business. The acquisition has been accounted for using the acquisition method, and the recognized amounts of identifiable assets acquired and liabilities assumed at fair value are as follows: $21.4 million of petroleum and natural gas assets, $1.7 million of E&E assets, and $2.7 million of decommissioning obligations. This property acquisition was acquired with full tax pools and no working capital items.

In the period from October 4, 2012 to December 31, 2012, the acquisition contributed revenues of $2.4 million and net earnings of $0.5 million which are included in the statement of income (loss) and comprehensive income (loss).

Acquisition of Waseca Energy

On November 1, 2012, Twin Butte completed the business combination with Waseca Oil & Gas Inc. ("Waseca"), which provided for the acquisition by Twin Butte of all the issued and outstanding common shares of Waseca on the basis of 0.51 common shares (30,222,481 issued) of Twin Butte for each Waseca share plus cash of $56.7 million, for total consideration of $145 million. The value of the Common Shares issued as consideration was determined based on the trading value of Twin Butte's Common Shares on the date of acquisition. The purpose of the acquisition was to increase Twin Butte's presence and size in its core heavy oil fairway allowing for operating synergies. Waseca was amalgamated with Twin Butte following the completion of the Acquisition and the transaction was accounted for as a business combination using the acquisition method of accounting under IFRS 3 Business Combinations.

The following are the estimated fair values of the net assets of Waseca:

	Total
Petroleum and natural gas properties	135,000
Exploration and evaluation assets	16,288
Net working capital	10,787
Deferred income tax liability	(28,057)
Decommissioning obligation	(5,242)
Goodwill	16,083
Total net assets acquired	$ 144,859

The net working capital asset consists of the following:

	Total
Accounts receivable	8,209
Deposits and prepaid expenses	134
Accounts payable and accrued liabilities	(12,322)
Cash	14,766
Net working capital	$ 10,787

Consideration	Total
Common Shares (30,222,481 shares at $2.92 per share)	88,159
Cash	56,700
	$ 144,859

The recognized identifiable assets and liabilities assumed were based on best estimates by Twin Butte's management and were based on valuations prepared by external engineers. The consideration paid exceeded the fair value of net assets acquired and goodwill was recognized in the amount of $16.1 million. Goodwill was recognized on this transaction due to the rise in Twin Butte's share price from the initial valuation date, to the close of the transaction. The decommissioning obligation was fair valued using the credit–adjusted rate of 6%. The accounting for the business combination remains subject to further refinement as additional cost estimates and tax balances are finalized.

The transaction costs related to the acquisition amounted to $1.1 million and were expensed in the statement of income (loss) and comprehensive income (loss). In the period from November 1, 2012 to December 31, 2012, the acquisition contributed revenues of $10.9 million and net earnings of $0.07 million which are included in the statement of income (loss) and comprehensive income (loss).

NOTE 8. EXPLORATION AND EVALUATION ASSETS

Balance at January 1, 2012	$	17,044
Acquisitions		54,305
Transferred to property, plant and equipment (note 8)		(49)
Dispositions		(483)
Exploration and evaluation expense		(5,038)
Balance at December 31, 2012	$	65,779
Acquisitions and purchases		16,268
Transferred to property, plant and equipment (note 8)		(1,698)
Dispositions		(1,526)
Exploration and evaluation expense		(14,798)
Balance at December 31, 2013	**$**	**64,025**

Exploration and evaluation ("E&E") assets consist of the Company's land and exploration projects which are pending the determination of technical feasibility and commercial viability. In the year ended December 31, 2013, expense of $14.3 million was recognized ($5.0 million – December 31, 2012) for current and future land expiries for which management has neither budgeted nor planned further exploration. The remainder of E&E expense during the year relates to geophysical and geological activities which have been undertaken prior to the ownership of land and lease rights.

During the year ended December 31, 2013, Twin Butte completed the sale of several non-core E&E assets in Alberta for net proceeds of $3.5 million ($0.5 million – December 31, 2012). A $3.3 million gain was recognized on these transactions ($nil – December 31, 2012).

NOTE 9. PROPERTY AND EQUIPMENT

Cost:	Oil & gas properties	Office equipment	Total
Balance at December 31, 2011	$ 387,109	$ 219	$ 387,328
Additions	93,455	–	93,455
Acquisitions	406,000	–	406,000
Changes in decommissioning provision	13,737	–	13,737
Transfers from E&E assets (note 5)	49	–	49
Disposals	(8,015)	–	(8,015)
Balance at December 31, 2012	$ 892,335	$ 219	$ 892,554
Additions	101,621	–	101,621
Acquisitions	423,067	–	423,067
Changes in decommissioning provision	59,637	–	59,637
Transfers from E&E assets (note 5)	1,698	–	1,698
Disposals	(61,704)	–	(61,704)
Balance at December 31, 2013	**$ 1,416,654**	**$ 219**	**$ 1,416,873**
Accumulated depletion, depreciation and impairment losses:			
Balance at December 31, 2011	$ 110,630	$ 219	$ 110,849
Depletion and depreciation expense	99,471	–	99,471
Impairment expense	17,237	–	17,237
Disposals	(4,331)	–	(4,331)
Balance at December 31, 2012	$ 223,007	$ 219	$ 223,226
Depletion and depreciation expense	134,725	–	134,725
Impairment expense	49,519	–	49,519
Disposals	(35,202)	–	(35,202)
Balance at December 31, 2013	**$ 372,049**	**$ 219**	**$ 372,268**
Net Carrying Value:			
December 31, 2012	669,328	–	669,328
December 31, 2013	**1,044,605**	**–**	**1,044,605**

The Company capitalized $3.5 million of general and administrative expenses ($3.2 million – December 31, 2012) and $1.2 million of share based compensation expenses ($2.5 million – December 31, 2012) directly related to development and production activities for the year ended December 31, 2013.

Future development costs on proved plus probable undeveloped reserves of $343 million as at December 31, 2013 are included in the calculation of depletion ($262 million – December 31, 2012).

During the year December 31, 2013 the Company disposed of the Jayar property for proceeds of $19.5 million, resulting in a gain of $6.5 million. Total dispositions in 2013, which included Jayar and several other non-core properties, totaled $26.1 million ($6.4 million – December 31, 2012). A $2.1 million net gain was recognized on these transactions ($3.0 million gain – December 31, 2012).

At December 31, 2013, the Company assessed for indicators of impairment for all of its CGUs. Reductions to long term forecasted future natural gas benchmark pricing indicated that CGUs that produce a high level of natural gas may be impaired. Further, external engineer reserve valuations for the Heavy Oil CGU decreased from the prior year, which indicated potential impairment for this CGU. For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment or its reversal, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs of disposal and value in use. These key judgments include estimates about recoverable reserves (see Note 4 – Significant accounting judgments, estimates and assumptions), forecast benchmark commodity prices, royalties, operating costs and discount rates.

Twin Butte estimated the recoverable amount for these CGUs based on the fair value less costs of disposal, determined with an after-tax discount rate of 9.5 percent (December 31, 3012 – 9.5 percent), forecasted cash flows over the estimated life of reserves, and an independent industry reserve engineer price deck. The discount rate is derived from the post-tax weighted average cost of capital for Twin Butte's peer group. The forecasted cash flows are prepared over the estimated life of the reserves in the CGUs, which range from 20 to 50 years. The commodity prices used to estimate the fair value less costs of disposal are those used by independent industry reserve engineers.

Based on the assessment, after-tax recoverable amount for the Plains CGU was $27.2 million. This recoverable value did not exceed the carrying value of the CGU and a total non-cash, pre-tax impairment charge of $1.6 million ($1.2 million after tax) was recognized. The after-tax recoverable amount for the Heavy Oil CGU was determined to be $465.8 million. This recoverable value did not exceed the carrying value of the CGU. After impairing the goodwill associated with this CGU (Note 10), the total non-cash pre-tax impairment charge was $48.0 million ($36.0 million after tax). At December 31, 2012, due to sustained low natural gas current and forward prices, the Company impaired the West-Central, Plains and Deep Basin CGUs for $17.2 million.

The following table outlines forecasted commodity prices used in Twin Butte's CGU impairment tests at December 31, 2013. The exchange rate is forecasted at 0.95 $US/$CAN.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Thereafter
WTI (US$/bbl)	95.00	95.00	95.00	95.00	95.30	96.60	98.50	100.50	102.50	104.60	2%
Alberta AECO (Cdn$/mcf)	4.01	4.27	4.53	4.75	5.01	5.27	5.33	5.43	5.54	5.64	2%

The following table indicates the sensitivity of the December 31, 2013 impairment of the property, plant and equipment to changes in the discount rate and forecasted commodity prices:

($000's)	Increase in rate or price	Decrease in rate or price
Discount rate, 1% change	23,892	(25,458)
WTI, $5 change	(53,743)	56,628
AECO, $1 change	(2,758)	4,158

NOTE 10. GOODWILL

Balance at December 31, 2012	$	31,402
Impairment of goodwill	$	(31,402)
Balance at December 31, 2013	**$**	**–**

The balance in goodwill at December 31, 2012 relates to the Heavy Oil CGU. At December 31, 2013, the Company completed an impairment test of this CGU. The recoverable amount was less than the carrying value of the CGU, including goodwill, and as such, goodwill was impaired.

For the purposes of determining whether impairment of goodwill has occurred, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs to sell and value in use. The estimated recoverable reserves, forecast benchmark commodity prices, royalties, operating costs and discount rate used in the impairment calculation of goodwill are equivalent to those outlined in Note 9 – Property and Equipment for the impairment test of property and equipment at December 31, 2013. The Company used an after-tax discount rate of 9.5 percent. A 1 percent increase or decrease in the after-tax discount rate would not create nor reduce impairment of goodwill, as the total impairment exceeded goodwill.

NOTE 11. BANK INDEBTEDNESS

At December 31, 2013, the Company's dedicated bank facility consists of a revolving line of credit of $375 million and an operating line of credit of $25 million, extendible annually at the request of the Company for a further 364 days, subject to approval of the lenders and repayable one year after the expiry of the revolving period. The credit facility is with a syndicate of six Canadian chartered or international banks and provides that advances may be made by way of Canadian prime rate and U.S. base rate loans, bankers' acceptances, LIBOR Loans, or standby letters of credit/guarantees. Following the annual credit facility review and extension in May 2013, the facility was upgraded to its current level in November 2013 with the acquisition of Black Shire. The next review is scheduled for April 2014.

Interest rates are based on the Bank of Canada prime rate, plus 1% to 2.5% as determined by a pricing grid using the Company's debt to earnings before interest, taxes, depreciation, and amortization (EBITDA) ratio for the preceding four quarters. The bank currently charges prime plus 1.25%. The effective rate for three months ended December 31, 2013 was 4.0% (4.2% – December 31, 2012). As at December 31, 2013, the Company's facility was not in default.

The Company's revolving credit facility contains standard commercial covenants for facilities of this nature, including a requirement for Twin Butte to maintain a current ratio of not less than 1.0:1.0. The current ratio is defined as the ratio of (i) current assets, excluding financial derivatives, plus any undrawn availability under the credit facility to (ii) current liabilities, excluding financial derivatives and the drawn portion of the credit facility. The facility also contains a covenant which limits the maximum volume of financial derivatives in the subsequent 12 months to 80% of current production. Covenants are tested at the end of each fiscal quarter and the Company is in compliance as at December 31, 2013.

NOTE 12. CONVERTIBLE DEBENTURES

On December 18, 2013, the Company completed the issuance of convertible unsecured subordinated debentures (the "Debentures") for gross proceeds of $85.0 million ($81.4 million net of issuance costs) at a price of $1,000 per debenture. The debentures pay interest at a rate of 6.25% per annum, payable in arrears on a semi-annual basis on June 30 and December 31 of each year, commencing on June 30, 2014. The debentures mature on December 31, 2018.

The debentures are convertible at the option of the holder into common shares at a fixed conversion price of $3.05 per share. After December 31, 2016, the Company may redeem the debentures in whole or part provided the common shares' weighted average trading price during a specified period prior to redemption is not less than 125% of the conversion price.

The debentures have been classified as debt (net of issuance costs) with the residual value allocated to shareholders' equity. The fair value of the debt portion of the debentures was determined using a similar debt instrument without a conversion feature. The issuance costs will be amortized over the term of the debentures and the debt portion will accrete to the principle balance at maturity. The accretion of issuance costs and the interest paid are expensed on the statement of income and comprehensive income.

Debt component, December 31, 2012	–
Issuance, net of transaction costs	77,587
Accretion of convertible debentures	61
Debt component, December 31, 2013	**77,648**
Equity component, December 31, 2012	–
Issuance, net of transaction costs and deferred tax	2,879
Equity component, December 31, 2013	**2,879**

NOTE 13. DECOMMISSIONING PROVISION

Decommissioning obligations are based on the Company's net ownership in wells and facilities, and management's best estimate of future costs to abandon and reclaim those wells and facilities as well as an estimate of the future timing of the costs to be incurred.

The Company has estimated the present value of its total decommissioning provision to be $181.8 million at December 31, 2013 ($89.0 million – December 31, 2012), based on a total future liability of $318.6 million ($127.7 million – December 31, 2012). Payments to settle the obligations occur over the operating lives of the underlying assets and are estimated to be from 2 to 50 years, with the majority of costs to be incurred after 2025. Due to changes in both the average remaining time to decommissioning and long term risk free rates, the risk free rate used to calculate the present value of the decommissioning liability was increased to 3% from 2.5% in the previous year. The estimated inflation rate remained unchanged at 2% (2% – December 31, 2012).

Changes to the decommissioning provision are as follows:

	Year ended Dec 31, 2013	Year ended Dec 31, 2012
Decommissioning provision, beginning of period	**88,991**	38,401
Liabilities incurred	**4,555**	3,195
Liabilities settled	**(3,287)**	(1,140)
Liabilities acquired from acquisitions	**37,474**	36,748
Liabilities reduced from dispositions	**(3,543)**	(378)
Effect of change in risk free rate (1)	**28,890**	16,187
Revisions in estimated cash outflows	**26,192**	(5,645)
Accretion of decommissioning provision	**2,486**	1,623
Decommissioning provision, end of period	**181,758**	88,991

(1) These amounts include the revaluation of acquired decommissioning liabilities at the end of the period using a risk-free discount rate. At the date of acquisition, acquired decommissioning liabilities are valued using a credit adjusted risk-free discount rate.

NOTE 14. SHAREHOLDERS' EQUITY

Authorized

The Company has authorized an unlimited number of voting Common Shares and an unlimited number of Preferred Shares without nominal or par value.

	Number of common shares *(000's)*	Share capital $
Balance at December 31, 2011	135,419	227,520
Common shares issued pursuant to corporate acquisitions	108,915	287,737
Common shares issued under share award plan	3,271	6,052
Common shares issued under option plan	102	241
Common shares issued pursuant to the DRIP	636	1,676
Other	(31)	–
Balance at December 31, 2012	248,312	523,226
Common shares issued pursuant to corporate acquisitions	54,012	116,126
Common shares issued pursuant to subscription receipts	35,898	70,001
Common shares issued under share award plan	2,155	4,911
Common shares issued pursuant to the DRIP and SDP	2,703	5,556
Share issue costs, net of tax	–	(2,574)
Balance at December 31, 2013	**343,080**	**717,246**

The Company issued 54,012,276 shares to shareholders of Black Shire through the acquisition, which closed on November 5, 2013 (note 7a).

Through private placement, the Company also issued 35,898,000 subscription receipts, priced at $1.95 per receipt and representing one common share to be awarded upon closing of the acquisition of Black Shire. Upon closing on November 5, 2013, 35,898,000 shares were granted to holders of the receipts and Twin Butte received gross proceeds of $70 million (Net proceeds – $67 million).

During the year December 31, 2013, 2.1 million share and performance share awards were exercised by employees, resulting in the granting of 2.1 million shares.

The total number of shares reserved for Share-based payments is 34,307,956 (24,831,200 – December 31, 2012). As at December 31, 2013 there were 5,352,603 share and performance share awards, including reinvested dividends (4,199,716 – December 31, 2012) and 640,434 (895,434 – December 31, 2012) options outstanding under the plans or a total of 2% of outstanding shares.

Dividends declared during the year ended December 31, 2013 totaled $52.3 million ($37.2 million – December 31, 2012), equivalent to $0.192 per weighted-average share ($0.182 per weighted average share – December 31, 2012). Of these dividends declared, $4.4 million were reinvested in shares through the dividend reinvestment program ("DRIP"), and $1.0 million were declared through the Stock Dividend Program ("SDP"). In the year ended December 31, 2012, $1.7 million was reinvested in shares through the DRIP. Initiated in May 2013, the SDP allows shareholders to choose to receive dividends in the form of shares of Twin Butte at a 5% discount to the current weighted average price in lieu of a cash dividend.

Share-based payments

(a) Share award plan

Share awards may be granted to employees, officers, directors and service providers, and the Board has reserved up to 10% of outstanding Common Shares less outstanding options for issuance to eligible participants. A portion of share awards are granted with a performance factor feature, where upon vesting, the value of the share award is multiplied by a factor between 0 and 2. Annual performance factors are set by the board of directors and dependent on the performance of the Company relative to pre-defined corporate performance measures for the period. All share awards are managed under the Share Award Incentive Plan and have a maximum term of 5 years and vest in equal one-third increments on each anniversary of the grant. Share awards are measured at fair value at the date of grant determined in reference to the Company's share price on grant date, and the resulting share-based payment expense is recognized on a graded-vesting basis over the related vesting period.

The following table sets forth a reconciliation of outstanding share awards and related dividend and performance factor activity through December 31, 2013:

	Restricted share awards	Weighted average fair value at grant date	Performance share awards	Weighted average fair value at grant date
Outstanding at January 1, 2012	–	–	–	–
Converted from options	4,638,938	1.27	–	–
Granted	1,603,529	2.53	1,224,734	2.54
Granted – Performance factor	–	–	429,754	2.54
Reinvested dividends	199,931	1.96	63,271	2.50
Vested and converted to common shares	(3,534,870)	1.16	–	–
Forfeited	(425,571)	2.41	–	–
Outstanding at December 31, 2012	2,481,957	$ 2.17	1,717,759	$ 2.54
Granted	2,007,852	2.26	1,185,783	2.16
Granted – Performance factor	–	–	382,933	2.45
Reinvested dividends	285,691	2.30	169,458	2.44
Vested and converted to common shares	(1,288,758)	1.91	(842,791)	2.53
Forfeited	(426,199)	2.44	(321,082)	2.42
Outstanding at December 31, 2013	**3,060,543**	**$ 2.32**	**2,292,060**	**$ 2.33**

Twin Butte recorded share-based payment expense for the year ended December 31, 2013 was $4.9 million (December 31, 2012 – $4.4 million).

A 15% forfeiture rate were used to estimate the Company's share-based payment expense for the year ended December 31, 2013 (December 31, 2012 – 35%).

(b) Stock option plan

Following the initiation of the Share Award Plan in January 2012, there have been no further stock options granted and remaining outstanding options will be either exercised or forfeited. Stock options have a maximum term of five years and vest in equal one-third increments on each anniversary of the grant. Stock options were measured at fair value on the date of the grant using a Black-Scholes option pricing model, and the resulting share-based payment expense is recognized on a graded-vesting basis over the related vesting period.

The following table sets forth a reconciliation of stock option plan activity through to December 31, 2013:

	Number of options	Weighted average exercise price
Outstanding at January 1, 2012	10,027,636	$ 1.60
Exercised	(101,499)	1.62
Forfeited/Converted to share awards	(9,030,703)	1.50
Outstanding at December 31, 2012	895,434	$ 2.54
Exercised	(23,333)	1.26
Forfeited	(231,667)	2.57
Outstanding at December 31, 2013	**640,434**	**$ 2.72**

The following table outlines the weighted average exercise price and years to expiry for all outstanding options:

	December 31, 2013			December 31, 2012		
Exercise Price	**Number of Options Outstanding**	**Weighted Average Exercise Price $**	**Weighted Average Years to Expiry**	Number of Options Outstanding	Weighted Average Exercise Price $	Weighted Average Years to Expiry
$0.92 – 1.24	–	–	–	10,000	0.98	1.89
$1.25 – 1.51	**1,667**	**1.31**	**1.26**	11,667	1.31	2.26
$1.52 – 3.32	**638,767**	**2.73**	**2.36**	873,767	2.68	3.39
	640,434	**2.72**	**2.35**	895,434	2.65	3.36

Net Income (loss) Per Share

The following table sets forth the details of the computation of basic and diluted net income per share:

	Twelve months ended December 31	
	2013	2012
Net income (loss) for the period	**$ (115,633)**	$ 31,530
Weighted average number of basic shares (000's)	**265,191**	204,181
Effect of dilutive securities:		
Stock options and share awards (000's)	**–**	1,400
Weighted average number of diluted shares (000's)	**265,191**	205,581
Net income (loss) per share basic ($)	**(0.44)**	0.15
Net income (loss) per share diluted ($)	**(0.44)**	0.15

Diluted income per share amounts reflect the potential dilution that could occur if stock options were exercised and share awards were converted. The treasury stock method is used to determine the dilutive effect, whereby any proceeds from the exercise and the amount of compensation expense, if any, attributed to future services not yet recognized, are assumed to be used to purchase common share at the average market price during the periods.

Due to the net loss for the year ended December 31, 2013, share awards and stock options potentially convertible into 6.0 million shares have been excluded from the calculation of diluted net income (loss) for the period, as the impact would have been anti-dilutive. Convertible debentures have also been excluded from the calculation, as the conversion price was greater than the average share price during the period.

In the year ended December 31, 2013 and 2012, outstanding stock options, share awards, and convertible debentures were the only potentially dilutive instruments.

NOTE 15. SALES PER PRODUCT

	Year ended December 31,	
	2013	2012
Heavy oil	**$ 329,966**	$ 262,316
Light & Medium oil	**42,842**	21,338
Natural gas	**15,531**	13,178
Natural gas liquids	**6,249**	7,897
Total petroleum and natural gas sales	**$ 394,588**	$ 304,729

NOTE 16. GENERAL & ADMINISTRATION ("G&A") EXPENSE

	Year ended December 31,	
	2013	2012
Staff salaries and benefits	**$ 11,805**	$ 9,660
Rent and insurance	**1,145**	968
Office and other costs	**6,410**	5,573
Capitalized G&A	**(3,479)**	(3,190)
Capitalized overhead recoveries	**(3,364)**	(2,404)
	$ 12,517	$ 10,607

NOTE 17. FINANCE EXPENSE

	Year ended December 31,	
	2013	2012
Interest and bank charges	**$ 8,275**	$ 5,679
Interest on convertible debentures (1)	**262**	–
Accretion on convertible debentures (1)	**61**	–
Accretion on decommissioning provision	**2,486**	1,623
Total	**$ 11,084**	$ 7,302

(1) Convertible debentures were issued on December 13, 2013, resulting in 18 days of finance expenses in 2013.

NOTE 18. SUPPLEMENTAL CASH FLOW INFORMATION

	Year ended December 31, 2013	2012
Changes in non-cash working capital:		
Accounts receivable	**$ 11,229**	$ 9,903
Deposits and prepaid expenses	**(1,066)**	(851)
Accounts payable and accrued liabilities	**(2,458)**	447
Dividends Payable	**2,139**	3,350
	$ 9,844	$ 12,849
Changes in non-cash working capital relating to:		
Operating activities	**$ (3,333)**	$ (3,127)
Financing activities	**2,139**	3,350
Investing activities	**11,038**	12,626
	$ 9,844	$ 12,849

NOTE 19. INCOME TAX EXPENSE

(a) Deferred income tax expense:

The provision for income taxes reflects an effective tax rate which differs from Federal and Provincial statutory tax rates. The main differences are as follows:

For the years ended	2013	2012
Income (loss) before taxes	**$ (144,628)**	$ 45,116
Statutory income tax rate (1)	**25.0%**	26.0%
Expected income taxes	**(36,157)**	11,730
Stock based compensation	**1,228**	1,141
Change in expected tax rate	**(1,015)**	(396)
Non-deductible transaction costs	**–**	687
Goodwill impairment	**7,851**	–
Negative goodwill	**–**	(346)
Return to provision true-up and other	**(902)**	770
Deferred income tax expense / (recovery)	**$ (28,995)**	$ 13,586
Effective Tax rate	**20.0%**	30.1%

(1) The statutory rate consists of the combined statutory tax rate for the Company for the years ended December 31, 2013 and December 31, 2012. The general combined Federal/Provincial tax rate in Alberta was reduced to 25.0% in 2012, which combined with to increased revenue in Saskatchewan for an overall rate of 26.0%. In 2013, increased revenues in Alberta reduced the rate to 25.0%.

(b) Deferred income tax liability:

At December 31, 2013 a deferred tax liability of $31.3 million (December 31, 2012 – $31.5 million) has been recognized.

	2013	2012
Property, plant, and equipment	$ (97,068)	$ (60,116)
Decommissioning	45,440	23,138
Commodity derivatives	8,059	(7,074)
Share issue cost	1,338	538
Eligible scientific research & experimental development expenditures	3,625	3,770
Non-capital loss carryforwards	12,972	13,007
Other	(930)	–
Unrecognized deferred tax assets	(4,784)	(4,784)
Deferred income tax (liability)/asset	$ (31,348)	$ (31,521)

Unrecognized deferred tax assets relate to resource tax pools where there is uncertainty as to whether a taxable benefit will be available in the future. Non-capital loss carryforwards expire no earlier than 2023.

(c) Components of the net deferred income tax liability:

	Dec 31, 2013	Dec 31,2012
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	50,135	22,554
Deferred tax assets to be recovered within 12 months	21,299	13,115
	71,434	35,669
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	(102,782)	(43,304)
Deferred tax liabilities to be recovered within 12 months	–	(23,886)
	(102,782)	(67,190)
Deferred tax (liability)/asset	(31,348)	(31,521)

The deferred income tax liabilities and assets to be settled (recovered) within 12 months represents Management's estimate of the timing of the reversal of temporary differences and does not relate to the current income tax expense (if any) in the subsequent year.

(d) Movement in Deferred Tax Assets & Liabilities:

Deferred Income Tax Liabilities	Property, Plant and Equipment	Convertible Debentures	Other	Total
As at December 31, 2012	60,116	–	4,784	64,900
Acquired through business combinations	41,015	–	–	41,015
Recognized in equity	–	944	–	944
Charged/(credited) to earnings	(4,063)	(14)	–	(4,077)
As at December 31, 2013	**97,068**	**930**	**4,784**	**102,782**

Deferred Income Tax Assets	Risk Management	Decommissioning Liabilities	Tax Pools	Total
As at December 31, 2012	7,074	(23,138)	(17,315)	(33,379)
Acquired through business combinations	(2,489)	(9,368)	(380)	(12,237)
Recognized in equity	–	–	(900)	(900)
Charged/(credited) to earnings	(12,644)	(12,934)	660	(24,918)
As at December 31, 2013	**(8,059)**	**(45,440)**	**(17,935)**	**(71,434)**

Net Deferred Income Tax Liability	Total
As at December 31, 2012	31,521
Acquired	28,778
Recognized in equity	44
Charged/(credited) to earnings	(28,995)
As at December 31, 2013	**31,348**

NOTE 20. ACCOUNTS RECEIVABLE

As At	Dec 31, 2013	Dec 31, 2012
Trade	**35,228**	27,288
Joint Operations with Partners	**9,821**	9,592
Other	**3,625**	5,617
	48,674	42,497

NOTE 21. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As At	Dec 31, 2013	Dec 31, 2012
Trade	**46,395**	29,978
Royalties	**5,176**	4,815
Joint Operations with Partners	**3,887**	2,050
Accruals	**25,098**	23,979
	80,556	60,822

NOTE 22. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2013, the Company incurred related party costs totaling $8.0 million ($6.9 million – December 31, 2012) for oilfield services and legal counsel rendered by three companies of which an officer and director of Twin Butte is a director.

These costs were incurred in the normal course of business and were recorded at the amount exchanged between the parties. As at December 31, 2013, the Company had $1.7 million ($4.3 million – December 31, 2012) included in accounts payable and accrued liabilities related to these transactions.

Key Management Compensation

Key management includes Directors (executive and non-executive), the Executive Officers, and the Vice-Presidents. The compensation paid or payable to key management is as follows:

	Year ended December 31	
	2013	2012
Salaries, Director Fees and benefits	**4,019**	3,412
Stock Based Compensation	**3,351**	3,393
	7,370	6,805

As at December 31, 2013, there is a $4.0 million commitment (December 31, 2012 – $3.2 million) relating to change of control or termination of employment of key management personnel.

NOTE 23. COMMITMENTS AND CONTINGENCIES

Contractual obligations and commitments for base office rent and equipment are as follows:

($ thousands)	2014	2015	2016	2017	2018	thereafter
	2,028	2,022	2,041	2,075	1,158	–

NOTE 24. SUBSEQUENT EVENTS

Crude Oil Sales Price Derivative Contracts

Subsequent to December 31, 2013 the Company entered into several crude oil price derivatives. The average barrels and prices for these contracts are as follows:

Daily barrel (bbl) quantity	Term of contract	WTI (1) Fixed price per bbl ($CAD)	WCS (2) Fixed Price per bbl ($CAD)	Fixed price per bbl WCS (2) vs. WTI (1) ($CAD)
4,318	February 1, 2014 to December 31, 2014			$ (21.19)
3,500	April 1, 2014 to June 30, 2014			$ (20.04)
1,500	January 1, 2015 to June 30, 2015		$ 77.68	
500	January 1, 2015 to December 31, 2015		$ 77.75	
1,000	April 1, 2015 to June 30, 2015	$ 99.00		
2,500	January 1, 2015 to December 31, 2015	$ 98.97		

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Natural Gas Sales Price Derivative Contracts

Subsequent to December 31, 2013, the Company entered into natural gas price derivative contracts for the period of February 1, 2014 to December 31, 2014. The Company will swap 1,500 giga-joules (GJ) per day of Natural Gas at a fixed price of $3.84 per GJ, based on AECO daily pricing.

CORPORATE INFORMATION

OFFICERS

Jim Saunders
Chief Executive Officer

Bruce W. Hall
President & Chief Operating Officer

Bob Bowman
Vice President, Operations

Kent Porteous
Vice President, Business Development

Claude Gamache
Vice President, Geosciences

Gordon Howe
Vice President, Land

Preston Kraft
Vice President, Engineering

R. Alan Steele
Vice President, Finance & CFO

BOARD OF DIRECTORS

David Fitzpatrick (1) (3)
Chairman of the Board

Jim Brown (1) (3)

John Brussa (3)

Tom Greschner (2)

Jim Saunders

Warren Steckley (1) (2)

William A. (Bill) Trickett (2)

Member of:

(1) Audit Committee
(2) Reserves Committee
(3) Compensation, Nominating and Governance Committee

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National Bank of Canada
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SOLICITORS

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Calgary, AB

ENGINEERS

McDaniel & Associates Consultants Ltd.
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REGISTRAR & TRANSFER AGENT

Valiant Trust Company
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