Dated as of March 23, 2015

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, 2014 and the audited financial statements and MD&A for the year ended December 31, 2013. 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.

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 boe 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.

Non-GAAP Financial Measures – Certain measures in this document do not have a standardized meaning as prescribed by IFRS 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. Management's reasoning to use the measures, as well as reconciliation to the closest comparable GAAP measure, is detailed in the section entitled, "Non-GAAP Financial Measures".

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.

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	
	2014	2013	**2014**	2013
Sales *($000's)*				
Heavy oil	**54,666**	71,533	**302,844**	324,042
Light & Medium oil	**52,064**	27,864	**229,822**	41,626
Natural gas	**5,783**	3,879	**20,591**	15,236
Natural gas liquids	**(2,294)**	1,302	**1,816**	5,633
Total petroleum and natural gas sales	**110,219**	104,578	**555,073**	386,537
Average Daily Production				
Heavy oil (bbl/day)	**9,776**	13,123	**11,185**	13,630
Light & medium oil (bbl/day)	**8,553**	4,710	**7,870**	1,659
Natural gas (Mcf/day)	**13,849**	11,634	**12,616**	12,572
Natural gas liquids (bbl/day)	**(207)**	188	**98**	201
Total (boe/d)	**20,430**	19,960	**21,256**	17,585
% oil and liquids production	**89%**	90%	**90%**	88%
Average Twin Butte Realized Commodity Prices (1)				
Heavy oil ($ per bbl)	**60.78**	59.25	**74.18**	65.14
Light & Medium oil ($ per bbl)	**66.17**	64.31	**80.01**	68.72
Natural gas ($ per Mcf)	**4.54**	3.62	**4.47**	3.32
Natural gas liquids ($ per bbl)	**120.82**	74.89	**50.43**	76.88
Barrels of oil equivalent ($ per boe, 6:1)	**58.64**	56.95	**71.54**	60.22

(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	
	2014	2013	**2014**	2013
Benchmark Pricing				
WTI crude oil (US$ per bbl)	**73.15**	97.44	**93.00**	97.96
Edmonton crude oil (Cdn$ per bbl)	**75.56**	86.75	**94.62**	93.40
WCS crude oil (Cdn$ per bbl)	**67.45**	69.62	**81.76**	76.15
AECO natural gas (Cdn$ per Mcf) (2)	**3.41**	3.35	**4.27**	3.01
Exchange rate (US$/Cdn$)	**1.14**	1.05	**1.14**	1.03

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

Sales for the three months ended December 31, 2014 were $110.2 million, as compared to $104.6 million for the three months ended December 31, 2013, representing an increase of $5.6 million or 5%. Both sales volumes and the average realized commodity price increased from the prior year quarter, resulting in increased sales. Excluding the impact of derivative instruments, the average realized commodity price increased from $56.95 in the fourth quarter of 2013 to $58.64 during the fourth quarter of 2014. The increase in realized price is due to the Company's transition to higher-priced medium oil, as both the WTI and WCS benchmarks decreased from the prior year quarter. Although differentials narrowed, the WCS benchmark decreased 3% from the prior year quarter, due to a decrease in the WTI benchmark (US$). As the Company's revenues are substantially denominated in Canadian dollars, the weakened exchange rate has mitigated some of the effect of the 25% WTI benchmark decrease, which was an 18% decrease when converted to Canadian Dollars.

Production also increased from 19,960 boe/d in the three months ended December 31, 2013 to 20,430 boe/d for the three months ended December 31, 2014. This increase of 470 boe/d is due the Company's drilling program. Although the Company has not recently targeted gas-based drilling, natural gas sales volumes have increased from comparative periods due to associated gas volumes and a one-time prior period adjustment in the Pincher Creek area. This prior period adjustment resulted in increased natural gas sales (1,469 mcf/d) and reduced NGL sales (407 boe/d), for a net decrease of 162 boe/d for the quarter, and a sales reduction of $1.5 million. As a result of this adjustment, NGL sales are negative for the quarter.

Revenues for the year ended December 31, 2014 were $555.1 million, as compared to $386.5 million in the prior year, representing an increase of $168.6 million or 44%. This increase in revenue is attributed to a 21% production increase and a 19% increase in realized pricing. Production increased from 17,585 boe/d in the year ended December 31, 2013 to 21,256 boe/d in 2014 due to the Company's drilling program and the Provost properties acquired with the Black Shire acquisition. In line with increased benchmark pricing and the Company's transition to higher-priced medium oil, the average realized commodity price before hedging increased from $60.22 per boe in the year ended December 31, 2013 to $71.54 per boe in 2014.

CASH GAIN (LOSS) AND PROCEEDS ON DERIVATIVES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Realized gain (loss)	**9,152**	2,597	**(43,691)**	(4,114)
Cash proceeds - Swaptions	**–**	–	**–**	7,943
Gain (loss) and proceeds on derivatives	**9,152**	2,597	**(43,691)**	3,829
Realized gain (loss) on derivatives per boe	**4.87**	1.41	**(5.63)**	(0.64)
Cash proceeds on derivatives per boe – Swaptions	**–**	–	**–**	1.24
Gain (loss) and proceeds per boe	**4.87**	1.41	**(5.63)**	0.60

The Company realized a total cash gain on financial derivatives of $9.2 million ($4.87 per boe) for the three months ended December 31, 2014, compared to a total cash gain of $2.6 ($1.41 per boe) for the prior year quarter. During the quarter, the total gain was due to fixed price swaps, and was comprised of a $9.0 million gain on crude oil sales price derivatives and a $0.2 million gain on natural gas sales price derivatives, as compared to a $1.8 million gain on crude oil sales price derivatives and a $0.8 million gain on natural gas sales price derivatives in the fourth quarter of 2013.

The Company realized total cash losses on financial derivatives in the amount of $43.7 million ($5.63 per boe) for the year ended December 31, 2014. This total loss was due to fixed price swaps which settled in loss positions in the first 10 months of 2014 due to high benchmark pricing. In the prior year, the total cash proceeds on financial derivatives was $3.8 million ($0.60 per boe) and included a loss of $4.1 million on fixed price swaps and $7.9 million in proceeds from crude oil swaptions.

ROYALTIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Heavy Oil	**10,103**	16,899	**66,660**	74,196
Light & Medium oil	**7,015**	3,810	**30,409**	5,936
Natural Gas	**(205)**	(471)	**1,199**	(47)
NGLs	**(143)**	885	**2,240**	1,944
Total royalties	**16,770**	21,123	**100,508**	82,029
Total royalties per boe	**8.92**	11.50	**12.95**	12.78
% of P&NG Sales	**15%**	20%	**18%**	21%

Royalties for the three months ended December 31, 2014 were $16.8 million, as compared to $21.1 million for the three months ended December 31, 2013. As a percentage of sales, the average royalty rate for the third quarter of 2014 decreased to 15%, compared to 20% in the fourth quarter of 2013. Royalty rates decreased from the prior year quarter due to the addition of the Provost properties, which currently have lower royalty rates as a result of reduced rates for the first 18 months of production for horizontal drilled wells, and decreased benchmark commodity prices and the corresponding provincial royalty calculation input prices. Royalties also included a credit related to the Pincher Creek prior period adjustment, resulting in negative NGL royalties for the quarter. In Q4 2014, Heavy oil royalties averaged 18%, medium & light oil averaged 13% and gas averaged -4%.

Royalties for the year ended December 31, 2014 were $100.5 million, as compared to $82.0 million in the prior year. As a percentage of revenues, the average royalty rate for the year ended December 31, 2014 was 18%, compared to 21% in 2013. This decrease is due to the addition of the reduced royalty Provost properties. In the year ended December 31, 2014, heavy oil royalties averaged 22%, medium & light oil averaged 13% and gas averaged 6%.

OPERATING & TRANSPORTATION EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Operating expense	**39,263**	38,785	**164,353**	140,124
Transportation expense	**2,039**	1,513	**8,446**	7,608
Total operating & transportation expense	**41,302**	40,298	**172,799**	147,732
Operating expense per boe	**20.89**	21.12	**21.19**	21.83
Transportation expense per boe	**1.09**	0.82	**1.09**	1.19
Total per boe	**21.98**	21.94	**22.28**	23.02

Operating expenses were $39.3 million or $20.89 per boe for the quarter ended December 31, 2014 as compared to $38.8 million or $21.12 per boe for the three months ended December 31, 2013. The increase on an absolute dollar basis is attributable to increased volumes. In comparison to the prior year quarter, the reduction on a per boe basis is attributed to a shift in production mix toward additional volumes at the lower-cost Provost properties and reduced propane costs per litre, which were partially offset by an additional $0.4 million ($0.18/boe) in operating costs related to the Pincher Creek prior period one-time adjustment recorded in Q4 2014.

Although they have a lower operating cost than historical Twin Butte properties, the Provost properties bring additional exposure to power costs, as close to 30% of operating costs in the area are related to power consumption. To address this risk, the Company enters into fixed cost swaps for a portion of estimated power usage.

Operating expenses were $164.4 million or $21.19 per boe for the year ended December 31, 2014, as compared to $142.1 million or $21.83 in the prior year. The increase on an absolute dollar basis is attributable to increased volumes. On a per boe basis, cost decreases are also related to the production mix shift toward additional volumes at the lower-cost Provost properties and reduced propane costs.

Transportation expenses for the three months ended December 31, 2014 were $2.0 million or $1.09 per boe compared to $1.5 million or $0.82 per boe in the prior year comparative quarter. Transportation expenses for the year ended December 31, 2014 were $8.4 million or $1.09 per boe compared to $7.6 million or $1.19 per boe in the prior year. Annual decreases are associated with additional volumes at Provost properties, which have lower transportation costs.

The Company has combined operating and transportation costs of $22.28 per boe for the year, a 3% decrease from $23.02 per boe in 2013.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
G&A expense	**5,421**	5,324	**22,728**	19,360
Capitalized G&A expense	**(1,287)**	(990)	**(4,892)**	(3,364)
Recoveries	**(981)**	(816)	**(3,768)**	(3,479)
Total net G&A expense	**3,153**	3,518	**14,068**	12,517
Total net G&A expense per boe	**1.68**	1.92	**1.81**	1.95
Transaction expense	**–**	2,138	**–**	2,193
Transaction expense per boe	**–**	1.17	**–**	0.34

General and administrative expenses, net of recoveries and capitalized G&A, were $3.2 million or $1.68 per boe for the current quarter as compared to $3.5 million or $1.92 per boe in the prior year comparative quarter. The Company's expenses were consistent, but G&A recoveries associated with capital spending increased.

Net G&A expense for the year ended December 31, 2014 was $14.1 million or $1.81 per boe, compared to $12.5 million or $1.95 per boe in the prior year. While the Company's expenses increased due to staff changes and company growth, on a per boe basis G&A has decreased due to acquisition synergies.

FINANCE EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Interest and bank charges	**2,515**	2,860	**10,789**	8,275
Interest on convertible debentures [1]	**1,307**	262	**5,291**	262
Accretion on convertible debentures [1]	**310**	61	**1,242**	61
Accretion on decommissioning provision	**934**	725	**5,037**	2,486
Total finance expense	**5,066**	3,908	**22,359**	11,084
Total interest per boe	**2.03**	1.70	**2.07**	1.33
Total accretion per boe	**0.66**	0.43	**0.81**	0.40
Total finance expense per boe	**2.69**	2.13	**2.88**	1.73

(1) Convertible debentures were issued in December 2013.

For the three months ended December 31, 2014, finance charges were $5.1 million as compared to $3.9 million in the three months ended December 31, 2013. For the year ended December 31, 2014, finance charges also increased and were $22.4 million, as compared to $11.1 million in the prior year. This increase is due to increased debt levels as a result of the Provost acquisition and interest on the convertible debentures, issued in December 2013 with a face value of $85 million.

The Company's current interest charge on the bank line is prime of 2.85% plus a margin of 1.25% for a total rate of 4.10% and the Company's convertible debentures pay an interest rate of 6.25% annually. The Company utilized Bankers' Acceptances to lower the combined effective interest rate for the three and twelve months ended December 31, 2014 to 4.3% and 4.5%, respectively, (4.0% and 4.0% – December 31, 2013).

NETBACKS [2]

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

($ per boe)	**Q4 2014**	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Petroleum and natural gas sales [1]	**58.64**	74.13	79.42	73.58	56.95	77.34	63.00	44.86
Cash gain (loss) on financial derivatives	**4.87**	(6.26)	(12.02)	(8.71)	1.41	(10.87)	0.01	11.26
Royalties	**(8.92)**	(14.98)	(15.43)	(12.41)	(11.50)	(17.51)	(13.39)	(9.14)
Operating expense	**(20.89)**	(20.01)	(20.94)	(22.81)	(21.12)	(21.53)	(22.92)	(21.88)
Transportation expense [1]	**(1.09)**	(1.17)	(1.18)	(0.93)	(0.82)	(1.30)	(1.72)	(0.98)
Operating netback [2]	**32.61**	31.71	29.85	28.72	24.92	26.13	24.98	24.12
General and administrative expense	**(1.68)**	(1.74)	(2.32)	(1.53)	(1.92)	(1.62)	(2.05)	(2.21)
Transaction costs	**–**	–	–	–	(1.17)	–	–	(0.03)
Interest and bank charges	**(2.03)**	(2.15)	(2.27)	(1.85)	(1.70)	(1.18)	(1.37)	(1.00)
Funds flow netback [2]	**28.90**	27.82	25.26	25.34	20.13	23.33	21.56	20.88

(1) Certain transportation costs previously reported on a gross basis in 2013 were determined to be more accurately reflected on a net basis in petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

(2) Operating netback and Funds flow netback are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

SHARE-BASED PAYMENT EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Total	**1,182**	1,630	**4,485**	4,913
Total per boe	**0.63**	0.89	**0.58**	0.77

During the three months ended December 31, 2014, the Company expensed $1.2 million in share-based payment expense as compared to $1.6 million in the three months ended December 31, 2013. In the year ended December 31, 2014, share-based payment expense was $4.5 million, as compared to $4.9 million in 2013. This decrease is associated with a lower performance multiplier awarded in 2014. In 2013, the multiplier resulted in additional costs and performance share awards. The Company awarded 230,327 share awards and 203,237 performance share awards in the fourth quarter of 2014 as compared to 163,560 share awards and 499,559 performance share awards in the fourth quarter of 2013. Total share awards forfeited due to employee departures were 391,588 in the quarter versus 347,143 awards forfeited in the fourth quarter last year.

At December 31, 2014, the Company has 4,289,692 restricted share awards, 2,929,151 performance share awards and 500,434 options outstanding. The total of these options and share awards represents 2% of common shares outstanding.

UNREALIZED DERIVATIVE ACTIVITIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Unrealized gain (loss) on derivatives	**115,979**	(11,990)	**141,297**	(41,543)
Unrealized gain (loss) on derivatives per boe	**61.70**	(6.53)	**18.21**	(6.47)

As part of the financial management strategy to protect cash flows available for the payment of dividends and capital expenditures, the Company has adopted a commodity price risk management program. The purpose of the program is to stabilize and hedge future cash flow against the unpredictable commodity price environment, with an emphasis on protecting downside risk.

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 Company limits the maximum volumes hedged in relation to expected production.

The Company also enters into fixed price swaps with its power provider in order to stabilize future operating costs. In 2014, pre-hedge power costs have averaged $51 per megawatt hour, but were as high as $130 per megawatt hour in certain months. As power costs make up a significant percentage of operating expense in the Provost region, these contracts assist the Company in maintaining consistent and low operating costs in these areas. Current contracts are for approximately 80% of estimated power usage in 2015, and 40% in 2016.

Unrealized derivative assets and liabilities

As at December 31, 2014, the Company has a net unrealized financial derivative asset in the amount of $109.1 million, as compared to a liability of $32.2 million at December 31, 2013. This net unrealized gain position reflects weak WTI crude oil and AECO natural gas benchmark forward pricing for 2015. If WTI, WCS and AECO prices meet the forecasted benchmarks, these gain positions would be realized alongside decreased sales due to the weak commodity pricing in 2015.

The Company has recognized an unrealized gain on financial derivatives in the amount of $116.0 million for the three months ended December 31, 2014 as compared to $12.0 million unrealized loss for the prior year comparative quarter. For the twelve months ended December 31, 2014, the Company recognized an unrealized gain on financial derivatives of $141.2 million, compared to an unrealized loss of $41.5 million for the twelve months ended December 31, 2013. This unrealized gain is mainly due to a decrease in forward WTI pricing in 2015.

The following is a summary of derivatives as at December 31, 2014 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	WCS (2) Fixed Price per bbl	Fixed price per bbl WCS (2) vs. WTI (1)	Fixed written call price per bbl WTI (1)	Fair market value *$000's* ($CAD)
3,500	January 1, 2015 to December 31, 2015	$CAD	$99.76				42,659
1,000	January 1, 2015 to December 31, 2015	$USD	$94.60				15,982
2,000	January 1, 2015 to March 31, 2015	$CAD	$103.00				7,247
2,500	January 1, 2015 to June 30, 2015	$CAD	$105.88				18,948
1,000	April 1, 2015 to June 30, 2015	$CAD	$99.00				3,078
1,500	January 1, 2015 to December 31, 2015	$CAD		$79.25			17,358
2,000	January 1, 2015 to June 30, 2015	$CAD		$78.03			8,853
500	April 1, 2015 to June 30, 2015	$CAD		$80.00			1,565
5,000	January 1, 2015 to December 31, 2015	$CAD			$(20.77)		(3,576)
1,000	January 1, 2015 to March 31, 2015	$CAD			$(20.43)		(127)
3,000	January 1, 2015 to June 30, 2015	$CAD			$(20.45)		(893)
1,500	July 1, 2015 to December 31, 2015	$CAD			$(20.23)		(379)
1,000	July 1, 2015 to December 31, 2015	$CAD				$101.00	(4)
1,000	July 1, 2015 to December 31, 2015	$USD				$92.50	(2)
Crude oil fair value position							110,709

(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	Option Strike AECO Monthly	Fair Market Value *$000's*
4,000	January 1, 2015 to December 31, 2015	$3.77		1,608
2,000	January 1, 2016 to December 31, 2016		$3.75	(66)
Natural gas fair value position				1,542

Foreign Exchange Contracts

		Fixed $CAD/USD Prices		Fair Market Value
(USD $000's per month)	Term of contract	Lower end (1)	Upper end	*$000's*
2,877	January 1, 2015 to December 31, 2015	1.095	1.111	(1,903)
Foreign exchange contract fair value position				(1,903)

(1) The contract is structured whereby a monthly settlement price determined above 1.095 will settle at 1.111.

Power Purchase Price Derivatives

Daily Megawatt (MW) hours quantity	Term of contract	Fixed price per MW	Fair Market Value *$000's*
360	January 1, 2015 to December 31, 2015	$51.71	(1,079)
192	January 1, 2016 to December 31, 2016	$49.77	(209)
Power purchase contract fair value position			(1,288)

GAIN OR LOSS ON DISPOSITIONS

During the year ended December 31, 2014, the Company disposed of minor properties, containing both developed and undeveloped assets for net cash proceeds of $6.5 million ($29.6 million – December 31, 2013), resulting in a gain of $3.5 million ($5.4 million – December 31, 2013).

DEPLETION, DEPRECIATION & IMPAIRMENT

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Depletion & Depreciation	**48,038**	44,448	**180,972**	134,725
Depletion & Depreciation per boe	**25.56**	24.20	**23.33**	20.99

For the three months ended December 31, 2014, depletion and depreciation of capital assets was $48.0 million or $25.56 per boe compared to $44.4 million or $24.20 per boe for the prior year quarter. On an absolute basis this increase relates to increased production, and an increased depletion rate in the Heavy Oil CGU, following a reduction in reserves in the fourth quarter of 2014.

For the year ended December 31, 2014, depletion and depreciation of capital assets as $181.0 million, or $23.33 per boe, compared to $134.7 million or $20.99 per boe in the prior year.

At December 31, 2014, the Company assessed for indicators of impairment for all of its Cash Generating Units (CGUs). Reductions to current forecasted oil benchmark pricing indicated that oil-based CGUs may be impaired. Further, external engineer reserve valuations for the Pincher Creek and Heavy Oil CGUs decreased from the prior year, which indicated potential impairment for these CGUs. 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 Pincher Creek CGUs were determined to be higher than their respective recoverable amounts and a total non-cash impairment charge of $218.2 million was recognized ($163.6 million after tax). A $10.0 million impairment of E&E assets associated with the Heavy Oil CGU was also recognized. In the prior year, due to sustained low natural gas current and forward prices and negative reserve revisions, the Company impaired the Plains and Heavy Oil CGUs for a total of $49.6 million.

INCOME TAXES

Deferred tax amounted to a $27.3 million recovery for the three months ended December 31, 2014 compared to $19.6 million recovery for the three months ended December 31, 2013. In the year ended December 31, 2014, deferred tax amounted to a $17.6 million recovery, as compared to a $29.0 million recovery in the prior year. The recovery is the result of impairment-related reductions in deferred liabilities related to PP&E.

The Company has existing tax losses and pools of approximately $716.3 million at December 31, 2014. 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)	**2014**	2013	**2014**	2013
Net Income (loss)	**(84,086)**	(88,028)	**(57,340)**	(115,633)
Net Income (loss) per share	**(0.24)**	(0.28)	**(0.17)**	(0.44)

Net and comprehensive income for the three months ended December 31, 2014 was a loss of $84.1 million, compared to a net and comprehensive loss of $88.0 million in the three months ended December 31, 2013. Net and comprehensive income for the year ended December 31, 2014 was $57.3 million, compared to a net and comprehensive loss of $115.6 million in the prior year. The net loss in the current year is mainly due to non-cash impairments.

SELECTED ANNUAL INFORMATION

	Twelve months ended December 31		
($000's except per share amounts)	**2014**	2013	2012
Petroleum and natural gas sales (1)	**555,073**	386,537	298,634
Net Income (loss)	**(57,340)**	(115,633)	31,530
Per share basic	**(0.17)**	(0.44)	0.15
Per share diluted	**(0.17)**	(0.44)	0.15
Total assets	**1,043,249**	1,165,638	845,261
Total non-current financial liabilities	**327,063**	329,829	193,625
Dividends declared	**67,304**	52,286	37,249
Dividends declared per share	**0.194**	0.197	0.182

(1) Certain transportation costs previously reported in 2013 and 2012 were determined to be more accurately reflected as location differentials for petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

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 2014**	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Average production (boe/d)	**20,430**	20,981	21,109	22,529	19,960	16,263	16,849	17,254
Petroleum and natural gas sales (1)	**110,219**	143,088	152,566	149,200	104,578	115,709	96,590	69,660
Operating netback (per boe) (2)	**32.61**	31.71	29.85	28.72	24.92	26.13	24.98	24.12
Funds flow (2)	**54,324**	53,699	48,520	51,384	36,978	34,899	33,058	32,423
Per share basic	**0.16**	0.15	0.14	0.15	0.12	0.14	0.13	0.13
Per share diluted	**0.16**	0.15	0.14	0.15	0.12	0.14	0.13	0.13
Net income (loss)	**(84,086)**	34,805	7,181	(15,240)	(88,028)	8,111	(6,082)	(29,633)
Per share basic	**(0.24)**	0.10	0.02	(0.04)	(0.28)	0.03	(0.02)	(0.12)
Per share diluted	**(0.24)**	0.10	0.02	(0.04)	(0.28)	0.03	(0.02)	(0.12)
Corporate acquisitions (2)	**–**	–	–	–	356,521	–	–	–
Capital expenditures (2)	**34,128**	43,884	21,724	37,890	33,632	9,048	14,871	19,625
Total assets	**1,043,249**	1,150,834	1,152,659	1,174,100	1,165,638	802,916	790,056	815,040
Net debt (2)	**353,299**	355,918	352,198	363,659	361,612	179,013	193,750	200,542

(1) Certain transportation costs previously reported in 2013 were determined to be more accurately reflected as location differentials for petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

(2) Operating netback, Funds flow, Corporate acquisitions, Capital expenditures and Net debt are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

Quarterly variances in sales are connected to changes in production volumes and prices. 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 through an acquisition at Provost. In Q1, Q2, and Q3 2014, increased production, changes in the Company's production mix and high commodity prices resulted in significantly increased sales. Commodity price changes reduced sales in Q4 2014.

Through its strategy to protect cash flows and the 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 steadily increased during 2013. In Q4 2013, despite decreased pricing from Q3, the higher netback on the Provost properties increased funds flow from operations. In Q1 2014, funds flow increased significantly to $51.4 million due to increased revenue associated with increased production and realized sales prices. In Q2 2014, funds flow was above historical levels, but decreased from Q1 2014 due to slightly reduced production. Funds flow in Q3 and Q4 2014 continued this increasing trend, due to higher netbacks on Provost properties and cost savings.

Quarterly variances in net income, however, are largely driven by non-cash items, such as impairments, unrealized gains or losses on derivatives, deferred tax expense or recovery, and gains or losses on asset acquisitions and dispositions. In Q1 2013 the net loss was due to unrealized losses on derivatives. In the third 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. In Q1 2014 net losses were also mainly due to unrealized losses on derivatives. In Q2 and Q3 2014 net income was due to unrealized gains on derivatives and gains on the sale of non-core assets. In Q4 2014, the net loss was related to impairment losses, which offset unrealized gains on derivatives.

DIVIDENDS

Cash dividends declared for the three months ended December 31, 2014, which includes dividends declared and payable on December 31, 2014 and is net of the DRIP and SDP, were $14.5 million ($14.2 million – December 31, 2013). Cash dividends declared for the twelve months ended December 31, 2013 were $59.0 million ($46.3 million – December 31, 2013).

FUNDS FLOW FROM OPERATIONS (1) AND TOTAL PAYOUT RATIO (1)

Funds flow from operations ("Funds Flow") and the payout and total payout ratios are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures. 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)	**2014**	2013	**2014**	2013
Funds flow (1)	**54,324**	36,978	**207,927**	137,358
Funds flow per share	**0.16**	0.12	**0.60**	0.52
Dividends declared	**(17,394)**	(15,577)	**(67,304)**	(52,286)
Capital Expenditures (1)	**(34,128)**	(33,632)	**(137,627)**	(77,175)
Payout ratio (1)	**95%**	133%	**99%**	94%
Reinvested dividends (DRIP and SDP)	**2,912**	1,164	**8,354**	5,556
Cash dividends declared	**(14,482)**	(14,413)	**(58,950)**	(46,730)
Total payout ratio (net of DRIP and SDP) (1)	**89%**	130%	**95%**	90%

(1) Funds flow, Capital expenditures, Payout ratio and Total payout ratio are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

Twin Butte's corporate strategy aims to provide shareholders with long term total returns comprised of both income and moderate growth. The Company targets 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 annual payout does not exceed cash flow, on an on-going basis where required. For the three months ended December 31, 2014, the total payout ratio was 89%, due to a seasonally lower level of capital expenditures, and market conditions. This ratio decreased from Q3 2014. For the year ended December 31, 2014, the total payout ratio was 95%, consistent with Company strategy.

Funds flow from operations for the three months ended December 31, 2014 was $54.3 million, an increase from fourth quarter 2013 funds flow of $37.0 million, due to a full quarter with the Provost acquisition, and increased netbacks associated with our transition to medium oil barrels. This represents $0.16 per diluted share compared to $0.12 per diluted share for in 2013, as increased funds flow outpaced the increased number of shares outstanding.

Funds flow from operations for the year ended December 31, 2014 was $207.9 million, an increase from funds flow of $137.4 million in 2013, also associated with a full with the Provost acquisition, which occurred in November 2013, and the transition to medium oil barrels. This represents $0.60 per diluted share compared to $0.52 per diluted share for in 2013, as increased funds flow outpaced the increased number of shares outstanding.

CAPITAL EXPENDITURES AND PP&E ADDITIONS

($000's)	Three months ended December 31 2014	2013	Twelve months ended December 31 2014	2013
Land acquisition	**814**	2,443	**1,531**	3,766
Geological and geophysical	**776**	222	**1,553**	2,420
Drilling and completions	**20,483**	20,302	**92,350**	65,234
Equipping and facilities	**11,375**	10,164	**43,806**	31,538
Other	**1,287**	817	**4,892**	3,478
Development capital (1)	**34,735**	33,948	**144,132**	106,436
Property acquisitions - Cash paid	**–**	–	**–**	370
Property dispositions - Cash received	**(607)**	(316)	**(6,505)**	(29,631)
Capital expenditures (1)	**34,128**	33,632	**137,627**	77,175

(1) Development capital and Capital expenditures are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

During the fourth quarter of 2014, the Company invested $34.7 million on development capital, an increase from $33.9 million in development capital invested in Q4 2013. The Company's development capital expenditures for the quarter were focused in the Provost and Wildmere areas, with successful drilling of 4 (4.0 net) oil wells at Provost; 3 (2.0 net) oil wells at Wildmere; 3 (3.0 net) wells at Horseshoe; as well as 8 (8.0 net) wells at various other oil properties, and 1 (1.0 net) service wells. During the quarter, the Company also completed property dispositions for net proceeds of $0.6 million, compared to $0.3 million in 2013.

For the year ended December 31, 2014, the Company invested $144.1 million on development capital, an increase from $106.4 million in 2013. Proceeds from property dispositions in 2014 totaled $6.5 million, compared to $29.3 million in the prior year.

Drilling Results

Three months ended December 31	2014 Gross	2014 Net	2013 Gross	2013 Net
Crude oil	**19**	**18.0**	25	23.3
Dry and abandoned	**–**	**–**	1	1.0
Total	**19**	**18.0**	26	24.3
Success rate (%)		**100%**		96%

Twelve months ended December 31	2014 Gross	2014 Net	2013 Gross	2013 Net
Crude oil	**106**	**102.7**	90	88.3
Dry and abandoned	**3**	**3.0**	7	7.0
Total	**109**	**105.7**	97	95.3
Success rate (%)		**97%**		93%

Drilling Results by Well Type

Twelve months ended December 31	2014 Gross	2014 Net	2013 Gross	2013 Net
Medium oil – horizontal	**52**	**52**	2	2.0
Heavy oil – horizontal	**34**	**30.7**	39	37.3
Heavy oil – vertical	**16**	**16.0**	46	46.0
Service	**4**	**4.0**	3	3.0
Dry and abandoned	**3**	**3.0**	7	7.0
Total	**109**	**105.7**	97	95.3
Success rate (%)		**97%**		93%

Undeveloped Land

The Company's undeveloped land holdings have decreased from December 31, 2013, as conversions from drilling, dispositions and expiries were greater than purchases.

	At December 31, 2014	At December 31, 2013
Gross acres	**901,893**	958,432
Net acres	**367,364**	418,382

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. Twin Butte considers these measures and the related ratio to be key measures of liquidity and the management of capital resources.

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2014**	2013	**2014**	2013
Funds flow (1)	**54,324**	36,978	**207,927**	137,358
Annualized funds flow (1)	**217,296**	147,912	**207,927**	137,358
Net debt (1)	**353,299**	361,612	**353,299**	361,612
Net debt to annualized funds flow (1)	**1.6**	2.4	**1.7**	2.6

(1) Funds flow, Annualized funds flow and Net debt are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

For the three months ended December 31, 2014, the annualized net debt to funds flow ratio was 1.6, a decrease from the prior year quarter, which was 2.4, and from 1.7 in Q3 2014. This reduction is due to increasing funds flow associated with the Company's transition to medium barrels, as well as conservative capital spending in Q4 2014. Based on net debt of $353.3 million at December 31, 2014, and forecasted annual funds flow for 2015 based on current benchmark oil pricing, the Company expects the net debt to annualized funds flow ratio to be less than 2.5 for 2015.

The Company reviews capital expenditures on an on-going basis to ensure that funds flow will provide adequate funding. In cases such as the current commodity price environment, where funds flow may not be adequate to provide funding for all planned capital expenditures, the Company will adjust capital expenditures and dividends to manage debt levels. This diligent monitoring of funds flow from operations, capital spending, dividend payments and resulting debt levels has allowed Twin Butte to maintain a significant undrawn portion of $117.1 million on the Company's dedicated credit facility of $365 million. Due to the undrawn portion on the credit facility and 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

At December 31, 2014, the Company's dedicated bank facility consists of a revolving line of credit of $340 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 if not extended. The annual credit facility review was completed in May 2014, with the current revolving period scheduled for expiry on May 28, 2015. The facility is also subject to a semi-annual borrowing base review performed by the banking syndicate, based primarily on reserves, commodity prices, and other factors estimated by the lenders. Although the Company fully expects that the revolving period will be extended at the next review, a decrease to the borrowing base could lead to a reduction in the current $365 million credit facility. In the case where the borrowing base is reduced below the amount drawn, ($248 million at December 31, 2014), the Company has 60 days to remedy through various methods, such as asset sales, equity issuances, or debt restructuring.

The credit facility is with a syndicate of seven 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. The facility contains standard commercial covenants for facilities of this nature, including a requirement for Twin Butte to maintain an adjusted current ratio of not less than 1.0:1.0, which includes the undrawn portion of the credit facility as a current asset. The facility also contains a covenant that limits financial commodity agreements to less than 80% the average daily production of the prior quarter at the time the commodity agreement is signed. As 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. Non-commodity financial instruments, such as power and currency agreements, are required by covenant to have a maximum term of 36 months, and aggregate amounts hedged must not be more than 60% of the facility's borrowing base. At December 31, 2014, the Company is in compliance with all debt covenants.

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 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. As at December 31, 2014, no conversions or redemptions have occurred.

SHARE CAPITAL

In 2014, 2.4 million shares were issued on account of vested share and performance share awards that were exercised and 4.5 million shares were issued for the DRIP and SDP dividend programs, compared to 2.2 million shares issued on account of share awards, and 2.7 million shares issued for the DRIP and SDP dividend programs in 2013. The DRIP and SDP programs were suspended in January 2015.

On July 8, 2014, the Company completed a common share private placement, issuing 1,817,220 common shares at a price of $1.80 per common share to officers, directors and employees of Twin Butte for total gross proceeds of approximately $3.3 million. The price was based on the volume-weighted average share price on the Toronto Stock Exchange for the five trading days preceding the announcement of the private placement.

As of March 23, 2015 the Company has 353,317,358 Common Shares, 467,134 stock options and 13,370,725 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 $218.2 million (December 31, 2013 – $182.0 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, 2014	Less than one year	One to three years	Three to five years	Total
Derivative liability	7,964	275	–	8,239
Bank indebtedness – principal (1)	–	247,898	–	247,898
Bank indebtedness – interest	9,916	3,305	–	13,221
Convertible debentures – principal (2)	–	–	85,000	85,000
Convertible debentures – coupon	5,312	10,625	5,312	21,249
Purchase obligations (3)	6,795	3,488	–	10,283
Other (4)	1,605	3,241	825	5,671
	31,592	268,832	91,137	391,561

(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 current renewal review was completed in May 2014. Management fully expects the facility to be extended in 2015.

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

(3) Purchase obligations are contracts to purchase and consume electricity during 2015 and 2016. The fair value of these contracts is recorded as a financial liability.

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

RELATED PARTY TRANSACTIONS

During the twelve months ended December 31, 2014, the Company incurred related party costs totaling $5.4 million ($8.0 million – December 31, 2013) for oilfield services and legal counsel rendered by three companies of which an officer and/or 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, 2014, the Company had $0.8 million ($1.7 million – December 31, 2013) included in accounts payable and accrued liabilities related to these transactions.

SUBSEQUENT EVENTS

Crude Oil Sales Price Derivative Contracts

Subsequent to December 31, 2014 the Company entered into a crude oil sales price derivative as follows:

Daily barrel (bbl) quantity	Term of contract	Fixed price per bbl WCS (1) vs. WTI (2)
1,000	July 1, 2015 to December 31, 2015	$(18.90)
1,000	January 1, 2016 to December 31, 2016	$(18.90)

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

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

Power Purchase Price Derivative Contracts

Subsequent to December 31, 2014 the Company entered into power purchase price derivatives for 144 megawatt hours per day during 2016 at a price of $42.22 per megawatt and 96 megawatt hours per day during 2017 at a price of $40.40 per megawatt.

NON-GAAP FINANCIAL MEASURES

Certain measures in this document do not have a standardized meaning as prescribed by IFRS 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. Management's reasoning to use the measures, as well as reconciliation to the closest comparable GAAP measure, is detailed below.

Funds Flow, Funds Flow Netback and Funds Flow - Annualized

Twin Butte uses the term "Funds Flow" and its derivatives, "Funds Flow Netback" and "Funds flow – Annualized" as indicators of financial performance, but the terms should not be considered an alternative to, or more meaningful than the closest comparable GAAP measure, "Cash provided by (used in) Operating Activities" as disclosed on the Statement of Cash Flows in the attached financial statements. Funds flow is presented in the Company's MD&A to assist management and investors in analyzing operating performance in the stated period. A reconciliation of Funds Flow to the Cash provided by (used in) Operating Activities is as follows:

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2014**	2013	**2014**	2013
Cash provided by (used in) Operating Activities	**50,256**	49,161	**203,656**	130,738
Expenditures on decommissioning provision	**2,785**	1,455	**5,044**	3,287
Change in non-cash working capital (Operating)	**1,283**	(13,638)	**(773)**	3,333
Funds flow	**54,324**	36,978	**207,927**	137,358
Total boe in the period (000's)	**1,880**	1,836	**7,758**	6,419
Funds flow netback ($/boe)	**28.90**	20.13	**26.80**	21.40
Annualizing factor	**4.0**	4.0	**1.0**	1.0
Funds flow – annualized	**217,296**	147,912	**207,927**	137,358

Net Debt

Twin Butte uses the term "Net Debt" as an indicator of financial performance and it is presented in the Company's MD&A and Financial Statements to assist management and investors in analyzing total cash-based obligations in the stated period. A reconciliation of Net Debt to the Balance Sheet is as follows:

($000's except per share amounts)	**December 31, 2014**	December 31, 2013
Bank Indebtedness	**247,898**	252,181
Convertible debentures	**78,890**	77,648
Working Capital Deficit	**26,511**	31,783
Net Debt	**353,299**	361,612

Working Capital Deficit

Twin Butte uses the term "Working Capital Deficit" as an indicator of financial performance. This term is presented in the Company's MD&A and Financial Statements to assist management and investors in analyzing net working capital amounts in the stated period. A reconciliation of Working Capital Deficit to the Balance Sheet is as follows:

($000's except per share amounts)	**December 31, 2014**	December 31, 2013
Accounts receivable	**(50,142)**	(48,674)
Deposits and prepaid expenses	**(4,958)**	(5,588)
Accounts payable and accrued liabilities	**76,082**	80,556
Dividend Payable	**5,529**	5,489
Working capital deficit (surplus)	**26,511**	31,783

Net Debt to Funds Flow – Annualized

"Net debt to funds flow – annualized" is a non-GAAP measure defined as the ratio of Net debt to Funds flow – annualized. Twin Butte uses this term to monitor whether funds flow from operations will be sufficient to cover all obligations, specifically the non-GAAP measure of net debt. Twin Butte considers this ratio to be a key measure of liquidity and management of capital resources.

Operating Netback, Field Netback and Funds Flow Netback

"Operating netback", "Field netback" and "Funds flow netback" are common metrics used in the oil and gas industry and are presented in the Company's MD&A to assist management and investors to evaluate oil and gas operating performance in the stated period. As they are industry specific terms, there is no comparable GAAP measure.

Operating Netback is determined as the sum of Petroleum and natural gas sales, Royalties, Operating Expense, and Transportation Expense as defined on the Statement of Income (Loss) and Comprehensive Income (Loss), and the Realized Gain (Loss) on financial instruments per note 5(a) to the financial statements, all on a per unit basis. Field netback is the operating netback, excluding the realized gain (loss) on financial instruments on a per-unit basis. Funds flow netback is the operating netback, plus general and administrative expense and transaction costs per the Statement of Income (Loss) and Comprehensive Income (Loss), and interest paid per the Statement of Cash Flows on a per-unit basis. Total units (boe) and each of the per-unit line items referenced above are also defined in the related sections of this MD&A.

Corporate Acquisitions

"Corporate Acquisitions" is a non-GAAP measure and includes the IFRS definition of total consideration plus working capital deficit (surplus) acquired in a corporate acquisition. Management uses this measure to analyze the total compensation paid for a corporate acquisition when working capital accounts are acquired.

Capital Expenditures and Development Capital

Management uses the Non-GAAP measures "Capital expenditures" and "Development Capital" in its analysis of cash used in investing activities. Capital expenditures and Development Capital are reconciled to GAAP measures, as defined on the Statement of Cash flows in the attached financial statements, below:

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2014**	2013	**2014**	2013
Expenditures on property and equipment	**(33,191)**	(31,275)	**(141,322)**	(100,934)
Expenditures on exploration and evaluation assets	**(1,544)**	(2,673)	**(2,810)**	(5,872)
Development capital	**(34,735)**	(33,948)	**(144,132)**	(106,806)
Proceeds on disposition of property and equipment	**31**	316	**3,509**	26,086
Proceeds on disposition of exploration and evaluation	**576**	–	**2,996**	3,545
Capital expenditures	**(34,128)**	(33,632)	**(137,627)**	(77,175)

Payout Ratio and Total Payout Ratio

Management uses the Non-GAAP measures "Payout Ratio" and "Total Payout Ratio" as indicators of financial performance and sustainability. A payout ratio of 100% indicates that the company has generated the cash flow necessary to fund dividends and capital investment. Payout ratio is defined as the non-GAAP measure, Funds flow, divided by the sum of the non-GAAP measure Capital expenditures and Dividends declared per the Statement of Changes in Shareholder's Equity in the financial statements. Total payout ratio is defined as Funds flow, divided by the sum of Capital expenditures and Dividends paid per the Statement of Cash Flows, which are net of dividends reinvested in shares per the Dividend Reinvestment Program and the Stock Dividend Program.

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, 2014 is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 9 – valuation of property and equipment;
- Note 12 – measurement of decommissioning provision;
- Note 13 – measurement of share-based compensation; and
- Note 18 – income tax expense.

The Company's significant areas of estimation uncertainty have not changed during the period.

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, 2014, 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.

Significant Accounting Policies

The Company has adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2014:

(i) *IAS 32 Financial Instruments: Presentation* — The Company adopted, as required, amendments to IAS 32. The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. IAS 32 did not impact the Company's interim financial statements.

(ii) *IFRIC 21 Levies* — The International Financial Reporting Interpretation Committee clarified in IFRIC 21 that an entity recognizes a liability for a levy when the activity that triggers payment occurs. For a levy that is triggered upon reaching a minimum threshold, the interpretation clarified that no liability should be anticipated before the minimum threshold is reached. The adoption of this interpretation did not have an impact to the Company's interim financial statements.

During the year ended December 31, 2014, the following standards were issued and are applicable to the company in future years:

(i) *IFRS 15: Revenue from Contracts with Customers* — In May 2014, the IASB issued this standard which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. The Company is currently evaluating the impact of the standard on the financial statements.

(ii) *IFRS 9: Financial Instruments* — In July 2014, the IASB issued this standard to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the financial statements.

The accounting policies followed in the audited financial statements are consistent with those of the previous year ended December 31, 2013.

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 PROCEDURES

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding disclosure.

Twin Butte's Chief Executive Officer and Chief Financial Officer have evaluated, or caused to be evaluated under their supervision, the effectiveness of Twin Butte's DC&P as at December 31, 2014. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Twin Butte's DC&P were effective as at December 31, 2014.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting ("ICFR"), as defined in National Instrument 52-109, means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management or other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

(a) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements.

Twin Butte's officers used the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to design ICFR. Twin Butte's Chief Executive Officer and Chief Financial officer have evaluated, or caused to be evaluated under their supervision, the effectiveness of ICFR at December 31, 2014. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Twin Butte's ICFR were effective as at December 31, 2014.

It should be noted that while Twin Butte's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P or ICFR will prevent all errors and/or fraud. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

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. During the year ended December 31, 2014, there were no changes to Twin Butte's ICFR that materially affected, or are reasonably likely to materially affect the Company's ICFR.