Quarterly Report

September 2014

Lonestar Resources, Ltd. (ASX:LNR, OTCQX: LNREF) is pleased to provide an update on its financial and operational results for the three months ended September 30, 2014 (3Q14).

Third Quarter Highlights

- Lonestar reported a 56% increase in net oil and gas production to 4,669 BOEPD in 3Q14, vs. 2,997 BOEPD in 3Q13, 81% of which was crude oil and NGL's. Lonestar's 3Q14 production also represented a 29% sequential increase over 2Q14 production levels.
- Net Revenues From Ordinary Activities increased 50% to US$32.0 million for 3Q14, vs. 3Q13 revenues of $21.2 million.
- EBITDAX increased 55% to $23.4 million for 3Q14 vs. $15.0 million for 3Q13, and rose 40% sequentially over 2Q14 levels.
- Net income was $19.1 million for 3Q14, or $0.03 per share vs. net income of $1.6 million reported for 3Q13.
- Lonestar spent $44.5 million during the quarter, associated with the drilling and completion of 7 Eagle Ford Shale wells, and included $2.2 million of lease acquisition costs.
- Lonestar continues to make progress in improving all phases of its business. Since the end of the quarter:
  - Lonestar recorded oil and gas production of 5,600 BOEPD in the month of October, 2014, representing a record for the Company, and an increase of 20% over production reported today for the third quarter of 2014.
  - After review of its year-to-date drilling, completion and production results, Lonestar's lead bank has recommended an increase in the Company's borrowing base from $108.8 million to $150.0 million. The increase is subject to final approvals.
  - Based on current rates of production and its capital plans, Lonestar sees a 2014 exit rate of 6,500 to 7,000 BOEPD, and sees 2014 EBITDAX of $92 to $97 million, based on the recent fall in NYMEX crude oil prices.
  - Lonestar's current drilling budget of $135 to $150 million in 2015 is expected to increase 2015 production by 30-55% and 2015 EBITDAX by 30-60%, compared to 2014 at current prices.

Contacts

Lonestar Resources, Ltd.
31 Carrington Street
Nedlands, WA 6009
+61-8-6430-9856

Lonestar Resources America, Inc.
600 Bailey Avenue, Suite 200
Fort Worth, Texas 76107
+1-817-546-6400

www.lonestarresources.com

Management

Managing Director & Chief Executive Officer
Frank D. Bracken, III

Chief Operating Officer
Barry D. Schneider

Senior Vice President
Tom H. Olle

VP- Geosciences
Scott E. Sabatka

Chief Financial Officer
Douglas W. Banister

Company Secretary
Mitchell Wells

Management's Discussion and Analysis

Lonestar Resources, Ltd. is pleased to announce its operational and unaudited financial results for the quarter ended September 30, 2014.

OVERVIEW

Lonestar Resources, Ltd. ("Lonestar" or the "Company") is listed on the Australian Securities Exchange (ASX) and the OTCQX in the United States, and is headquartered in Fort Worth, Texas. Lonestar Resources is focused on the acquisition, development and production of unconventional resources in the United States. Alongside optimizing cash flows from its Conventional assets, Lonestar is focusing its attention and capital to continuing its growth strategy in the crude oil window of the Eagle Ford Shale. Lonestar currently operates virtually 100% of its 30,306 net acres in the Eagle Ford, and continues to expand its leasehold. Lonestar believes it is capitalized to fund the development of its existing Eagle Ford Shale drilling inventory though internal means. Lonestar is also engaged in an early-stage project in the Bakken Petroleum System, where it has assembled a 52,559 acre leasehold (34,163 net acres) and tested light oil from the Bakken, Three Forks and Lower Lodgepole formations.

THIRD QUARTER 2014 HIGHLIGHTS

Corporate

- Lonestar recorded oil and gas production of 5,600 BOEPD in the month of October, 2014, representing a record for the Company, and an increase of 20% over sales reported today for the third quarter of 2014. The primary driver of this continued growth is the positive benefit of a full-month's production from Lonestar's first 2 producers in the Eastern Eagle Ford. Based on current rates of production and the Company's plans to place an additional 6.0 gross / 4.1 net Eagle Ford Shale wells onstream before year-end, Lonestar sees a 2014 exit rate of 6,500 to 7,000 BOEPD.
- As part of its semi-annual borrowing base review, which includes review of its year-to-date drilling, completion and production results, Lonestar's bank group, led by Wells Fargo, has recommended a 38% increase in the borrowing base on its Senior Secured Credit Facility from $108.8 million to $150.0 million. The increase is subject to final approvals from each member bank. At September 30, 2014, Lonestar's Long-Term Debt consisted of $220.0 million of 8 ¾% Senior Unsecured Notes and $22.0 million drawn on its Senior Secured Credit Facility, implying liquidity of $128 million at the end of the third quarter.

Operational

- Lonestar's net production for the third quarter of 2014 averaged 4,669 BOE per day, and was comprised of 3,288 barrels of oil per day, 489 barrels of NGL's per day, and 5,350 Mcf of natural gas per day. 3Q14 production was 56% higher 3Q13 levels. Third quarter production was comprised of 81% crude oil and natural gas liquids, and 19% natural gas.
- In the third quarter of 2014, Lonestar generated Discretionary Cash Flow of $18.5 million, a 58% increase over second quarter Discretionary Cash Flow of $11.7 million.
- Lonestar is generating significant improvement in total unit cash operating expenses in the Eagle Ford Shale, which it believes will insulate the Company from lower crude oil prices. Total cash unit operating expenses were reduced sequentially by 27%, from $40.16 per BOE in 2Q14 to $29.17 per BOE in 3Q14. Based on higher expected production volumes in 4Q14, Lonestar projects total unit expenses to continue to decline to a range of $27.69 and $27.44 per BOE
  - Lease Operating Expenses reduced 19% sequentially. In the second quarter of 2014, Lonestar's Eagle Ford Shale assets recorded LOE of $4.3 million, or $10.41 per BOE. Benefitting from cost control measures in its Western Region and the addition of low-cost producers in its Eastern Region, 3Q14 LOE was $4.7 million, or $8.44 per BOE. Lonestar sees fourth quarter LOE being reduced to a range between $8.35 and $8.10 per BOE.
  - Production Taxes fell 13% sequentially. Owing to a combination of lower crude oil prices and lower percentage tax rates on a higher mix of crude oil, Production taxes fell from $5.19 per BOE in 2Q14 to $4.52 per BOE in 3Q14. Lonestar sees fourth quarter 2014 Production Taxes ranging between $4.59 and $4.34 per BOE.
  - General & Administrative Expenses decreased 19% sequentially. Lonestar's General & Administrative Expense was $2.2 million, or $5.09 per BOE in 3Q14, which represents a 19% decrease compared to 2Q14 levels of $6.32 per BOE. Lonestar sees 4Q14 G&A per BOE ranging between $4.08 and $3.83 per BOE.
  - Interest Expenses decreased 39% sequentially. Lonestar's Interest Expense was $4.7 million in 3Q14, or $11.12 per BOE, which represents a 39% decrease compared to 2Q14 levels of $18.24 per BOE. Lonestar sees 4Q14 G&A per BOE ranging between $10.68 and $10.43 per BOE.
- Lonestar significantly increased its crude oil hedge positions for 2015. Currently, the Company has swaps covering approximately 2,500 barrels per day for 2015 at an average strike price of approximately $88.00 per barrel. Based on the consensus of analysts' published estimates, Lonestar's hedges cover 50% of the consensus of analyst's published estimates for Lonestar's 2015 crude oil production volumes.

Operations Review

EAGLE FORD SHALE TREND- WESTERN REGION

- **Asherton**- In central Dimmit County, no new wells were completed during the quarter. However, the Company has made significant progress in reestablishing producing rates on its 4 wells after fracture stimulation operations on its #9HS and #10HN wells knocked its 2 legacy producers offline. In the third quarter of 2014. production averaged 716 gross / 530 net BOEPD, compared to 747 gross / 553 net in the second quarter of 2014. Additionally, Lonestar has made considerable progress in stabilizing operating costs at Asherton. In 3Q14, Lease Operating Expenses were $0.3 million, or $6.39 per BOE, flat with the second quarter.
- **Beall Ranch-** In Dimmit and La Salle Counties, no new wells were completed during the quarter. However, the Company has made significant progress with respect to ameliorating producing rates on all 18 wells after fracture stimulation operations on its #32H, #33H and #34H wells knocked several legacy producers offline. In the third quarter of 2014, production averaged 3,212 gross / 2,354 net BOEPD, compared to 2,213 gross / 1,622 net BOEPD in the second quarter of 2014. Additionally, Lonestar has made considerable progress in reducing operating costs at Beall Ranch, achieving a 40% reduction in unit costs. In 3Q14, Lease Operating Expenses were $1.4 million, or $6.25 per BOE, compared to $1.5 million, or $10.50 per BOE in 2Q14.
- **Burns Ranch Area-** In La Salle County, Lonestar completed 3 wells on its Meiners lease, in which it holds an 85.0% WI and a 63.7% NRI. Lonestar drilled and completed the Meiners #1H with a perforated interval of 4,525'. The well was turned to the tanks at a cost of $5.1 million and placed into flowback in mid-September. Test rates for the #1H were 391 bopd and 567 Mcfgpd on a 18/64" choke, equating to a processed three-stream rate of 521 BOEPD. The #1H has now been online for 45 days and has registered a 30 day max IP of 314 bopd and 431 Mcfgpd, equating to a processed three-stream rate of 413 BOEPD while on an 18/64" choke. Lonestar drilled and completed the Meiners #2H with a perforated interval of 4,475'. The well was turned to the tanks at a cost of $6.7 million and placed into flowback in early October. Additional well costs were associated with a fishing job on the Meiners #2H, which was the result of stuck coiled tubing. Test rates for the #2H were 268 bopd and 363 Mcfgpd on a 16/64" choke, equating to a processed three-stream rate of 351 BOEPD. The #2H has now been online for 26 days and has yet to register a 30 day max IP. Lonestar drilled and completed the Meiners #3H with a perforated interval of 4,475'. The well was turned to the tanks at a cost of $5.1 million and placed into flowback in mid September. Test rates for the #3H were 344 bopd and 332 Mcfgpd on a 18/64" choke, equating to a processed three-stream rate of 420 BOEPD. The #3H has now been online for 45 days and registered a 30 day max IP of 228 bopd and 292 Mcfgpd, equating to a processed three-stream rate of 295 BOEPD while on an 18/64" choke.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, Lonestar is pleased to report more comprehensive results on its Pirate #K1H and Pirate L#1H wells, the first wells completed on leasehold acquired from Clayton Williams. The Pirate #K1H registered a 30 day max IP of 209 bopd and 95 Mcfgpd, equating to a processed three-stream rate of 231 BOEPD. The Pirate #L1H, which benefitted from real-time improvements in fracture stimulation design after difficulties encountered in the #K1H, has now been online for 105 days and has registered a 30 day max IP of 361 bopd and 165 Mcfgpd, equating to a processed three-stream rate of 405 BOEPD. These wells are both on pump, and producing at rates in excess of pump capacity. The Pirate #K1H continues to produce at its Max-30 rate after 105 days online. The Pirate #L1H is producing at 338 BOEPD after 105 days online, with only 25% of its frac load recovered.
- **Southern Gonzales County**- During the third quarter, Lonestar has drilled and completed 3 wells in Southern Gonzales County. The Harvey Johnson #1H, #2H & #3H have an average lateral length of 6,371 feet at an average TVD of 9,710 feet. Fracture stimulation of these wells is scheduled for November 4, 2014 with flowback to commence late November. Lonestar has a 50.0% Working Interest and a 37.5% NRI in these wells.

EAGLE FORD SHALE TREND- EASTERN REGION

- **Brazos County** - In western Brazos County, Lonestar drilled and completed the Ranger #A-4H with a perforated interval of 5,619'. The well was turned to the tanks at a cost of $7.4 million and placed into flowback in late September. Test rates for the A #4H were 674 bopd and 413 Mcfgpd on a 17/64" choke, equating to a processed three-stream rate of 778 BOEPD. The A #4H has now been online for 36 days and has registered a 30 day max IP of 567 bopd and 313 Mcfgpd, equating to a processed three-stream rate of 639 BOEPD while on an 18/64" choke. Lonestar drilled and completed the Ranger #B-1H with a perforated interval of 5,406'. The well was turned to the tanks at a cost of $6.3 million and placed into flowback in early late September. Test rates for the B #1H were 600 bopd and 387 Mcfgpd on a 17/64" choke, equating to a processed three-stream rate of 698 BOEPD. The B #1H has now been online for 36 days and has registered a 30 day max IP of 494 Bopd and 280 Mcfgpd, equating to a processed three-stream rate of 558 BOEPD.
- **Completions In Progress-** In Southern Robertson County, Lonestar has drilled and completed the Dunn #A-1H with a perforated interval of 5,720 feet. Lonestar also drilled and completed the Dunn #A-2H with a perforated interval of 5,995 feet. These wells are estimated to be inline with pre-drill AFE. Flowback of these wells commenced October 29, 2014, and initial rates are encouraging. Lonestar holds a 82.4% WI / 62.0% NRI in the Dunn wells. In Northern Brazos County, Lonestar drilled and completed the Scasta #3H with a perforated interval of 4,537 feet. Flowback on the Scasta #3H commenced today. Lonestar holds a 100.0% WI / 79.4% NRI in the Scasta #3H.

BAKKEN-THREE FORKS TREND

- **Poplar West, Montana-** Based on its geological analysis, core evaluation, and production testing, the Poplar West project area is prospective for the entire unconventional resource "Bakken Petroleum System", which includes the Basal Lodgepole, Upper Bakken Shale, Middle Bakken, Lower Bakken Shale and the Third and Fourth Benches of the Three Forks formations. Further, Poplar West is highly prospective for the Amsden, Charles, Heath, Mission Canyon and Nisku formations. After processing and interpreting its 105 square miles of 3-D seismic data covering the Poplar West project area. Lonestar and its partners have identified 39 Charles prospects (conventional) and 41 Nisku prospects (conventional) and a total of 340 drilling locations in the Non-conventional Bakken Petroleum System. In May, 2014, Lonestar submitted the application for the establishment of the Stone Turtle Indian Exploratory unit to the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), covering 52,559 gross acres and expects to receive approval imminently. As currently contemplated, formation of the unit would establish a 5-year primary term on all leasehold in the unit, in exchange for drilling activity. Lonestar believes it has strong support for future development from all governmental regulatory agencies including the BIA, BLM and the Fort Peck Tribe. Lonestar and its partners have commenced a process to farm-out a portion of their interest in Poplar West with a goal of completing an agreement by year-end 2014

2014 DRILLING AND COMPLETION PLANS

Lonestar has set a budget of 21 wells on its Eagle Ford Shale leasehold during 2014. The schedule below reflects the 24 wells Lonestar will drill and complete in 2014, 21 of which will be turned to production during the calendar year, with the other 3 coming online in early 2015. The opportunity to gain leasehold in a highly prolific area of Gonzales County, where IP's have frequently exceeded 1,500 bopd, caused the Company to defer completion dates by an average of 30 days for several wells it has scheduled for second half start-up.

- **1Q14**- The Company drilled and completed 5 wells, which were placed into flow back in late March. These included 2 at Asherton and 3 in Wilson County.
- **2Q14**- Lonestar drilled and completed 3 97.7% WI wells at Beall Ranch, which were placed into flow back on June 15th. Lonestar drilled and completed 2 wells in Wilson County on leasehold acquired from Clayton Williams in the Pirate Area. Lonestar commenced drilling in the Ranger-Dansby lease in Brazos County on June 14th.
- **3Q14**- On July 16th, Lonestar placed 2 100% WI wells onstream in Wilson County in the Pirate Area. Lonestar has drilled and completed 2 100% WI wells in Brazos County (Ranger-Dansby), and placed these wells online in late September. Lonestar placed its 3 85.0% WI wells in La Salle County (Meiners) on leases acquired from Clayton Williams in September. Lonestar has recently drilled and completed 3 50.0% WI wells on a farm-in in southern Gonzales County.
- **4Q14**- During the fourth quarter, plans to place an additional 6.0 gross / 4.1 net Eagle Ford Shale wells onstream. Lonestar has fracked 3 additional wells in Brazos and Robertson Counties (2 76.7% WI wells at Dunn and 1 100% WI well at Scasta), and these wells have recently been turned to flowback. Lonestar drilled all 3 of the wells it had an option to drill in southern Gonzales County, and Lonestar has contracted to commence frac operations November 4th, with flowback scheduled for late November, 2014. Lonestar has spudded the first of 3 wells on the 100% WI Gerke lease in La Salle County, which it expects to complete in December, 2014, and produce in January, 2015.

2014 DRILLING AND COMPLETION TIMETABLE

	1Q14	2Q14	3Q14	4Q14	2014
Western Eagle Ford					
Beall Ranch	0 - 0	3 - 3	0 - 0	0 - 0	3 - 3
Asherton	2 - 2	0 - 0	0 - 0	0 - 0	2 - 2
La Salle County	0 - 0	0 - 0	3 - 3	3 - 3	6 - 6
Western Eagle Ford	**2 - 2**	**3 - 3**	**3 - 3**	**3 - 3**	**11 - 11**
Central Eagle Ford					
Gonzo	1 - 1	0 - 0	0 - 0	0 - 0	1 - 1
Pirate	2 - 2	0 - 0	0 - 0	0 - 0	2 - 2
Wilson County	0 - 0	0 - 0	2 - 2	0 - 0	2 - 2
Gonzales County	0 - 0	0 - 0	0 - 0	3 - 3	3 - 3
Central Eagle Ford	**3 3**	**0 - 0**	**2 - 2**	**3 - 3**	**8 8**
Eastern Eagle Ford					
Brazos County	0 - 0	0 - 0	2 - 2	1 - 1	3 - 3
Robertson County	0 - 0	0 - 0	0 - 0	2 - 2	2 - 2
Eastern Eagle Ford	**0 - 0**	**0 - 0**	**2 - 2**	**3 - 3**	**5 - 5**
TOTAL EAGLE FORD	**5 - 5**	**3 - 3**	**7 - 7**	**9 - 9**	**24 - 24**

Management's Discussion and Analysis

Net Production (after royalties)

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	(bbls/day)	**2,010**	1,651	*22%*	**1,779**	1,223	*45%*
Natural Gas Liquids	(bbls/day)	**457**	264	*73%*	**384**	219	*75%*
Natural Gas	(Mcf/day)	**3,588**	2,086	*72%*	**2,998**	1,625	*84%*
Oil Equivalent	**(BOE/day)**	**3,066**	**2,263**	***35%***	**2,662**	**1,714**	***55%***
Central Eagle Ford Shale							
Crude Oil	(bbls/day)	**705**	-	-	**515**	-	-
Natural Gas Liquids	(bbls/day)	**1**	-	-	**0**	-	-
Natural Gas	(Mcf/day)	**3**	-	-	**1**	-	-
Oil Equivalent	**(BOE/day)**	**706**	-	-	**515**	-	-
Eastern Eagle Ford Shale							
Crude Oil	(bbls/day)	**167**	-	-	**179**	-	-
Natural Gas Liquids	(bbls/day)	**12**	-	-	**11**	-	-
Natural Gas	(Mcf/day)	**81**	-	-	**77**	-	-
Oil Equivalent	**(BOE/day)**	**193**	-	-	**203**	-	-
Total Eagle Ford Shale							
Crude Oil	(bbls/day)	**2,883**	1,651	*75%*	**2,472**	1,223	*102%*
Natural Gas Liquids	(bbls/day)	**470**	264	*78%*	**395**	219	*80%*
Natural Gas	(Mcf/day)	**3,673**	2,086	*76%*	**3,076**	1,625	*89%*
Oil Equivalent	**(BOE/day)**	**3,965**	**2,263**	***75%***	**3,380**	**1,714**	***97%***
Barnett Shale							
Crude Oil	(bbls/day)	-	-	-	-	-	-
Natural Gas Liquids	(bbls/day)	-	-	-	-	-	-
Natural Gas	(Mcf/day)	-	-	-	-	1,642	*-100%*
Oil Equivalent	**(BOE/day)**	-	-	-	-	**274**	***-100%***
Conventional							
Crude Oil	(bbls/day)	**405**	531	*-24%*	**453**	570	*-21%*
Natural Gas Liquids	(bbls/day)	**19**	-	-	**8**	3	*172%*
Natural Gas	(Mcf/day)	**1,678**	1,213	*38%*	**1,222**	1,295	*-6%*
Oil Equivalent	**(BOE/day)**	**704**	**734**	***-4%***	**665**	**789**	***-16%***
Total Company							
Crude Oil	(bbls/day)	**3,288**	2,183	*51%*	**2,925**	1,794	*63%*
Natural Gas Liquids	(bbls/day)	**489**	264	*85%*	**404**	222	*82%*
Natural Gas	(Mcf/day)	**5,350**	3,299	*62%*	**4,298**	4,562	*-6%*
Oil Equivalent	**(BOE/day)**	**4,669**	**2,997**	***56%***	**4,045**	**2,776**	***46%***

Lonestar's net production for the third quarter of 2014 averaged 4,669 BOE per day, and was comprised of 3,288 barrels of oil per day, 489 barrels of NGL's per day, and 5,350 Mcf of natural gas per day. 3Q14 production rose 56% over rates reported in 3Q13, and also represented a 29% sequential increase over reported volumes for the second quarter of 2014.

- Lonestar's net production from its Eagle Ford Shale assets averaged a 3,965 BOE per day during the third quarter of 2014, and was comprised of 2,883 barrels of oil per day, 470 barrels of NGL's per day, and 3,673 Mcf of natural gas per day. Third quarter volumes represented an increase of 75% compared to the third quarter of 2013, and a 32% increase sequentially. In the third quarter of 2014, 85% of the Company's Eagle Ford production was from liquid hydrocarbons. The increase was largely due to: a recovery in Beall Ranch and Asherton rates; first production from its Meiners wells; and a full quarter's production associated with the Pirate K #1H and L #1H. The quarter saw no contribution in sales from its first 2 wells in the Eastern Region, which were placed online at the end of September.
- Lonestar's net production from its Conventional assets averaged 704 BOE per day during the third quarter of 2014, and was comprised of 405 barrels of oil per day, 19 barrels of NGL's per day, and 1,678 Mcf of natural gas per day. 60% of the Company's Conventional production was from liquid hydrocarbons. 3Q14 production was 4% lower than levels reported in the third quarter of 2013. 3Q13 production includes 94 BOEPD of production from the Raccoon Bend, Oklahoma and Louisiana properties which have since been sold. However, Lonestar's Conventional assets registered a 6% sequential gain in production, in spite of the sale of 73 BOEPD of non-operated production in South Texas in June. Positive recompletion and pump optimization are responsible for the sequential growth, which were achieved at negligible capital costs.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Wellhead Commodity Price Realizations

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($/bbl)	**$95.39**	$104.17	-8%	$96.73	$103.21	-6%
Natural Gas Liquids	($/bbl)	**$31.58**	$32.05	-1%	$32.30	$28.79	12%
Natural Gas	($/Mcf)	**$3.84**	$3.32	16%	$4.25	$3.20	33%
Western Eagle Ford Shale	**($/BOE)**	**$71.76**	**$82.80**	**-13%**	**$74.08**	**$80.41**	**-8%**
Central Eagle Ford Shale							
Crude Oil	($/bbl)	**$95.46**	-	-	$96.84	-	-
Natural Gas Liquids	($/bbl)	**$25.08**	-	-	$25.08	-	-
Natural Gas	($/Mcf)	**$4.02**	-	-	$3.29	-	-
Central Eagle Ford Shale	**($/BOE)**	**$95.33**	**-**	**-**	**$96.77**	**-**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($/bbl)	**$96.01**	-	-	$95.55	-	-
Natural Gas Liquids	($/bbl)	**$32.68**	-	-	$32.96	-	-
Natural Gas	($/Mcf)	**$2.80**	-	-	$2.88	-	-
Eastern Eagle Ford Shale	**($/BOE)**	**$86.41**	**-**	**-**	**$87.13**	**-**	**-**
Total Eagle Ford Shale							
Crude Oil	($/bbl)	**$95.44**	$104.17	-8%	$96.67	$103.21	-6%
Natural Gas Liquids	($/bbl)	**$31.60**	$32.05	-1%	$32.31	$28.79	12%
Natural Gas	($/Mcf)	**$3.82**	$3.32	15%	$4.21	$3.20	32%
Total Eagle Ford Shale	**($/BOE)**	**$76.68**	**$82.80**	**-7%**	**$78.32**	**$80.41**	**-3%**
Barnett Shale							
Crude Oil	($/bbl)	**-**	-	-	-	-	-
Natural Gas Liquids	($/bbl)	**-**	-	-	-	-	-
Natural Gas	($/Mcf)	**-**	-	-	-	$3.37	-100%
Barnett Shale	**($/BOE)**	**-**	**-**	**-**	**-**	**$20.24**	**-100%**
Conventional							
Crude Oil	($/bbl)	**$92.98**	$100.85	-8%	$92.78	$93.21	0%
Natural Gas Liquids	($/bbl)	**$31.76**	-	-	$39.92	$49.45	-19%
Natural Gas	($/Mcf)	**$5.21**	$5.65	-8%	$6.16	$5.97	3%
Conventional	**($/BOE)**	**$66.83**	**$82.46**	**-19%**	**$75.01**	**$77.36**	**-3%**
Total Company Wellhead							
Crude Oil	($/bbl)	**$95.14**	$103.36	-8%	$96.07	$100.04	-4%
Natural Gas Liquids	($/bbl)	**$31.61**	$32.19	-2%	$32.47	$29.07	12%
Natural Gas	($/Mcf)	**$4.26**	$4.18	2%	$4.77	$4.05	18%
Total Company Wellhead	**($/BOE)**	**$75.19**	**$82.72**	**-9%**	**$77.77**	**$73.61**	**6%**

Lonestar's average wellhead commodity price for the third quarter of 2014 was $75.19 per barrel of oil equivalent (BOE), which was 9% lower than the $82.72 per BOE average price realized in the third quarter of 2013. Wellhead realizations declined largely due to an 8% ($8.66 per barrel) decrease in West Texas Intermediate compared to 3Q13 .

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $76.68 per BOE during 3Q14, a 7% decrease compared to 3Q13. While WTI prices fell $8.66 per bbl, Lonestar's average oil price benefitted from favorable localized basis and sales price improvements generated by its own remarketing efforts, which resulted in reduced discounts to WTI postings. NGL realizations fell 1% vs. 3Q13, owing to lower WTI prices. Natural gas realizations rose 15% to $3.52, in conjunction with higher Henry Hub gas prices, year-over-year.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $66.83 per BOE during 3Q14, down 19% versus 3Q13. This variance is also largely due to lower WTI pricing compared to 3Q13. Additionally the product mix has shifted from 72% crude oil and NGL's in 3Q13 to 60% crude oil and NGL's in 3Q14 due to higher gas production in West Texas and the higher rates associated with recompletion activities on the Company's non-operated leases in Lavaca County.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Wellhead Oil & Gas Revenues

		Three months ended September 30,			Nine Months Ended September 30,		
		2014	2013	% Change	2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($,000)	**$17,643**	$15,826	11%	**$46,807**	$34,348	36%
Natural Gas Liquids	($,000)	**$1,328**	$779	71%	**$3,372**	$1,717	96%
Natural Gas	($,000)	**$1,269**	$637	99%	**$3,463**	$1,415	145%
Western Eagle Ford Shale Revenues	**($,000)**	**$20,241**	**$17,242**	**17%**	**$53,642**	**$37,480**	**43%**
Central Eagle Ford Shale							
Crude Oil	($,000)	**$6,191**	$0	-	**$13,565**	$0	-
Natural Gas Liquids	($,000)	**$2**	$0	-	**$2**	$0	-
Natural Gas	($,000)	**$1**	$0	-	**$1**	$0	-
Central Eagle Ford Shale Revenues	**($,000)**	**$6,195**	**$0**	**-**	**$13,568**	**$0**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($,000)	**$1,478**	$0	-	**$4,639**	$0	-
Natural Gas Liquids	($,000)	**$37**	$0	-	**$101**	$0	-
Natural Gas	($,000)	**$21**	$0	-	**$60**	$0	-
Eastern Eagle Ford Shale Revenues	**($,000)**	**$1,537**	**$0**	**-**	**$4,801**	**$0**	**-**
Total Eagle Ford Shale							
Crude Oil	($,000)	**$25,313**	$15,826	60%	**$65,012**	$34,348	89%
Natural Gas Liquids	($,000)	**$1,368**	$779	76%	**$3,474**	$1,717	102%
Natural Gas	($,000)	**$1,291**	$637	103%	**$3,525**	$1,415	149%
Total Eagle Ford Shale Revenues	**($,000)**	**$27,972**	**$17,242**	**62%**	**$72,011**	**$37,480**	**92%**
Barnett Shale							
Crude Oil	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$0	-	**$0**	$1,507	-100%
Barnett Shale Revenues	**($,000)**	**$0**	**$0**	**-**	**$0**	**$1,507**	**-100%**
Conventional							
Crude Oil	($,000)	**$3,468**	$4,931	-30%	**$11,428**	$14,459	-21%
Natural Gas Liquids	($,000)	**$55**	$3	1507%	**$89**	$41	120%
Natural Gas	($,000)	**$804**	$631	27%	**$2,046**	$2,103	-3%
Conventional Revenues	**($,000)**	**$4,327**	**$5,565**	**-22%**	**$13,564**	**$16,603**	**-18%**
Total Company Wellhead							
Crude Oil	($,000)	**$28,781**	$20,757	39%	**$76,440**	$48,807	57%
Natural Gas Liquids	($,000)	**$1,422**	$782	82%	**$3,564**	$1,758	103%
Natural Gas	($,000)	**$2,095**	$1,268	65%	**$5,571**	$5,025	11%
Total Company Wellhead Revenues	**($,000)**	**$32,299**	**$22,808**	**42%**	**$85,575**	**$55,589**	**54%**

Lonestar's net wellhead oil and gas revenues for the third quarter of 2014 rose 42% to $32.3 million, versus $22.8 million a year ago. Revenue growth was a function of a 55% increase in production, partially offset by a 9% decline in realized wellhead prices. Wellhead oil and gas revenues also increased 22% sequentially over 2Q14 levels.

- Lonestar's net oil and gas revenues from its Eagle Ford Shale assets rose 62% to $28.0 million for the third quarter of 2014 versus $17.2 million a year ago. Revenue growth was driven by a 75% increase in production partially offset by a 7% decrease in wellhead price realizations per BOE. Crude oil contributed 90% of revenues, while natural gas liquids contributed 5% of revenues and natural gas contributed 5% of revenues.
- Lonestar net oil and gas revenues from its Conventional assets totaled $4.3 million during the third quarter of 2014, a 22% decrease over the third quarter of 2013. Crude oil contributed 80% of revenues while natural gas liquids contributed 1% of revenues and natural gas contributed 19% of revenues. The largest contributor to reduced revenues has been the ongoing sale of non-core, non-operated assets. To date, the Company has generated $4.9 million of proceeds from the sale of Conventional assets in Oklahoma, Louisiana and South Texas, which contributed 94 BOEPD in 3Q13.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Field Operating Expenses

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Western Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.73**	$5.69	36%	**$8.58**	$6.45	33%
Production Taxes	($/BOE)	**$4.25**	$4.57	-7%	**$3.46**	$4.61	-25%
Western Eagle Ford Shale	**($/BOE)**	**$11.98**	**$10.26**	**17%**	**$12.04**	**$11.05**	**9%**
Central Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$10.29**	$0.00	-	**$10.77**	$0.00	-
Production Taxes	($/BOE)	**$5.17**	$0.00	-	**$4.45**	$0.00	-
Central Eagle Ford Shale	**($/BOE)**	**$15.47**	**$0.00**	**-**	**$15.22**	**$0.00**	**-**
Eastern Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$13.07**	$0.00	-	**$8.53**	$0.00	-
Production Taxes	($/BOE)	**$6.31**	$0.00	-	**$4.05**	$0.00	-
Eastern Eagle Ford Shale	**($/BOE)**	**$19.38**	**$0.00**	**-**	**$12.58**	**$0.00**	**-**
Total Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$8.44**	$5.69	49%	**$8.91**	$6.45	38%
Production Taxes	($/BOE)	**$4.52**	$4.57	-1%	**$3.65**	$4.61	-21%
Total Eagle Ford Shale	**($/BOE)**	**$12.96**	**$10.26**	**26%**	**$12.56**	**$11.05**	**14%**
Barnett Shale							
Lease Operating Expense	($/BOE)	**$0.00**	$0.00	-	**$0.00**	$11.21	-100%
Production Taxes	($/BOE)	**$0.00**	$0.00	-	**$0.00**	$1.24	-100%
Barnett Shale	**($/BOE)**	**$0.00**	**$0.00**	**-**	**$0.00**	**$12.45**	**-100%**
Conventional							
Lease Operating Expense	($/BOE)	**$20.12**	$30.57	-34%	**$19.68**	$25.59	-23%
Production Taxes	($/BOE)	**$5.60**	$6.14	-9%	**$3.52**	$6.90	-49%
Conventional	**($/BOE)**	**$25.72**	**$36.71**	**-30%**	**$23.20**	**$32.49**	**-29%**
Total Company							
Lease Operating Expense	($/BOE)	**$10.20**	$11.78	-13%	**$10.68**	$12.36	-14%
Production Taxes	($/BOE)	**$4.68**	$4.96	-6%	**$3.63**	$4.93	-26%
Total Company	**($/BOE)**	**$14.88**	**$16.73**	**-11%**	**$14.31**	**$17.28**	**-17%**

Lonestar's field operating expenses for the third quarter of 2014 were $6.4 million, an increase of 39% over third quarter 2013 field operating expenses of $4.6 million. On a unit of production basis, the Company's field operating expenses declined 11% from 3Q13 to $14.88 per BOE. Lease Operating Expense ("LOE") was $4.4 million for the third quarter of 2014, a 35% increase over 2Q13 expenses. Higher lease operating expenses were primarily a function of a 56% increase in oil and gas production. Production taxes were $2.0 million for the third quarter of 2014, a 47% increase over comparable levels in 2013, attributable to substantial increases in production from the Company's Eagle Ford Shale properties.

- Lonestar's field operating expenses from its Eagle Ford Shale assets totaled $4.7 million during the third quarter of 2014, a 26% increase over the third quarter of 2013. On a unit of production basis, field operating expenses increased 26% to $12.96 per BOE, this increase is largely attributable to the purchase of older Austin Chalk wells from Clayton Williams, which were not owned in 3Q13. However, Lonestar's Eagle Ford Shale LOE in 3Q14 was $3.1 million, or $8.44 per BOE, which represented a 19% sequential reduction when compared to $10.41 per BOE in the prior quarter. Production taxes were $1.6 million, or $4.52 per BOE, compared to $1.0 million, or $4.57 per BOE in the year-ago quarter.
- Lonestar's field operating expenses from its Conventional assets totaled $1.7 million during the third quarter of 2014, a 33% decrease versus the third quarter of 2013. On a unit of production basis, field operating expenses decreased 30% to $25.72 per BOE. Lonestar continues efforts to lower operating expenses for the Conventional assets to maximize cashflow on a relatively flat producing asset. Lease operating expense was $1.3 million, or $20.12 per BOE, compared to $2.1 million, or $30.57 per BOE in 3Q13. Production taxes were $0.4 million, or $5.6 per BOE, compared to $0.4 million, or $6.14 per BOE in the quarter a year ago.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Field Netbacks

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Western Eagle Ford Shale							
Production Revenue	($/BOE)	$71.76	$82.80	-13%	$74.08	$80.41	-8%
Lease Operating Expenses	($/BOE)	$7.73	$5.69	36%	$8.58	$6.45	33%
Production Taxes	($/BOE)	$4.25	$4.57	-7%	$3.46	$4.61	-25%
Field Netback	**($/BOE)**	**$59.79**	**$72.55**	**-18%**	**$62.03**	**$69.36**	**-11%**
Field Netback	**($MM)**	**$16.9**	**$15.1**	**12%**	**$44.9**	**$32.33**	**39%**
Central Eagle Ford Shale							
Production Revenue	($/BOE)	$95.33	-	-	$96.77	-	-
Lease Operating Expenses	($/BOE)	$10.29	-	-	$10.77	-	-
Production Taxes	($/BOE)	$5.17	-	-	$4.45	-	-
Field Netback	**($/BOE)**	**$79.86**	**-**	**-**	**$81.54**	**-**	**-**
Field Netback	**($MM)**	**$5.2**	**-**	**-**	**$11.4**	**-**	**-**
Eastern Eagle Ford Shale							
Production Revenue	($/BOE)	$86.41	-	-	$87.13	-	-
Lease Operating Expenses	($/BOE)	$13.07	-	-	$8.53	-	-
Production Taxes	($/BOE)	$6.31	-	-	$4.05	-	-
Field Netback	**($/BOE)**	**$67.03**	**-**	**-**	**$74.55**	**-**	**-**
Field Netback	**($MM)**	**$1.2**	**-**	**-**	**$4.1**	**-**	**-**
Total Eagle Ford Shale							
Production Revenue	($/BOE)	$76.68	$82.80	-7%	$78.32	$80.41	-3%
Lease Operating Expenses	($/BOE)	$8.44	$5.69	49%	$8.91	$6.45	38%
Production Taxes	($/BOE)	$4.52	$4.57	-1%	$3.65	$4.61	-21%
Field Netback	**($/BOE)**	**$63.72**	**$72.55**	**-12%**	**$65.76**	**$69.36**	**-5%**
Field Netback	**($MM)**	**$23.2**	**$15.1**	**54%**	**$60.5**	**$32.33**	**87%**
Barnett Shale							
Production Revenue	($/BOE)	-	-	-	-	$20.24	-100%
Lease Operating Expenses	($/BOE)	-	-	-	-	$11.21	-100%
Production Taxes	($/BOE)	-	-	-	-	$1.24	-100%
Field Netback	**($/BOE)**	**-**	**-**	**-**	**-**	**$7.79**	**-100%**
Field Netback	**($MM)**	**-**	**-**	**-**	**-**	**$0.58**	**-100%**
Conventional							
Production Revenue	($/BOE)	$66.83	$82.46	-19%	$75.01	$77.36	-3%
Lease Operating Expenses	($/BOE)	$20.12	$30.57	-34%	$19.68	$25.59	-23%
Production Taxes	($/BOE)	$5.60	$6.14	-9%	$3.52	$6.90	-49%
Field Netback	**($/BOE)**	**$41.11**	**$45.76**	**-10%**	**$51.81**	**$44.87**	**15%**
Field Netback	**($MM)**	**$2.7**	**$3.1**	**-14%**	**$9.4**	**$9.6**	**-3%**
Total Company							
Production Revenue	($/BOE)	$75.19	$82.72	-9%	$77.77	$73.61	6%
Lease Operating Expenses	($/BOE)	$10.20	$11.78	-13%	$10.68	$12.36	-14%
Production Taxes	($/BOE)	$4.68	$4.96	-6%	$3.63	$4.93	-26%
Field Netback	**($/BOE)**	**$60.31**	**$65.99**	**-9%**	**$63.47**	**$56.33**	**13%**
Field Netback	**($MM)**	**$25.9**	**$18.2**	**42%**	**$69.8**	**$42.5**	**64%**

Lonestar's field netback for the third quarter of 2014 was $25.9 million, an increase of 42% over the field netback of $18.2 million in 3Q13. On a per BOE basis, field netbacks declined 9% to $60.31 in the third quarter of 2014 vs. $65.99 in the third quarter of 2013. The decrease in the per BOE field netback is associated solely with an 8% decrease in WTI pricing compared to 3Q13. Sequentially, Lonestar's field netback increased 26% over 2Q14 levels.

- Lonestar's field netback from its Eagle Ford Shale assets totaled $23.2 million during the third quarter of 2014, which represents a 54% increase in field netbacks compared to the $15.1 million reported in the third quarter of 2013. On a BOE basis, field netbacks declined 12% to $63.72 in third quarter of 2014 vs. $72.55 in 3Q14, largely influenced by a 7% reduction in crude oil prices .
- Lonestar's field netback from its Conventional assets totaled $2.7 million during the third quarter of 2014 which represents a 14% decrease in field netbacks compared to the $3.1 million reported in the third quarter of 2013. On a BOE basis, field netbacks declined 10% largely due to lower production revenue per BOE which caused lower crude oil realizations and higher gas sales volumes which are sold at a lower price per BOE compared to crude oil.

Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Total Expense	($,000)	$9,217	$7,767	19%	$26,755	$19,220	39%
Depreciation & Depletion	($/BOE)	$21.46	$28.17	-24%	$81.38	$81.93	-1%

Depletion is calculated using the units of production method, which involves dividing the carrying value of the assets by the estimated Proved reserves and applying this depletion rate to the production reported during the period. Depreciation of property plant and equipment is calculated on a declining basis so as to write down the net cost of each asset over its useful life, which ranges from 5 to 25 years.

Lonestar's Depreciation and Depletion expense for the third quarter of 2014 was $9.2 million, or $21.46 per BOE compared to $7.8 million, or $28.17 per BOE reported in the third quarter of 2013. Importantly, Lonestar's 3Q14 Depreciation and Depletion expense was reduced 37% sequentially versus 2Q14 rates of $29.42 per BOE.

General and Administrative Expenses

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Total Expense	($,000)	$2,187	$1,590	37%	$6,050	$5,789	5%
General & Administrative	($/BOE)	$5.09	$5.77	-12%	$18.40	$24.68	-25%

Lonestar reported General & Administrative expenses of $2.2 million for the third quarter of 2014, a 37% increase over the $1.6 million of General & Administrative expenses reported in the third quarter of 2013. On a BOE basis, the Company reported a 12% reduction in G&A per BOE of $5.09, compared to $5.77 reported in the third quarter of 2013. The reduction in G&A expenses on a BOE basis from 3Q14 to 3Q13 is largely a function of increasing production volumes. Lonestar achieved more significant reductions in G&A per BOE on a sequential basis, posting 19% improvement over 2Q14 results. Company expects continued reductions in G&A on a unit basis as Lonestar achieves further scale.

Finance Expenses

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Interest Expense	($,000)	$5,073	$1,053	382%	$12,383	$2,227	456%
Amortization of Finance Costs	($,000)	$275	$65	325%	$1,858	$136	1266%
Total Finance Costs	**($,000)**	**$5,348**	**$1,118**	**378%**	**$14,241**	**$2,363**	**503%**
Finance Costs	($/BOE)	$12.45	$4.06	**207%**	$43.32	$10.07	**330%**

Lonestar reported Finance expenses of $5.3 million for the third quarter of 2014, a 378% increase over the $1.2 million of Finance expenses reported in the third quarter of 2013. Increased Finance expenses are a result of the placement of the Company's 8.75% Notes coupled with borrowings from it Senior Secured credit facility. The Company's borrowings from its senior unsecured notes was $220.0 million during the quarter with interest expense averaging 8.75% on an annualized rate during the quarter. The Company's borrowings from its $108.5 million Revolver averaged $11.7 million during the quarter with interest expense averaging 2.24% on an annualized rate during the quarter.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Hedging Revenues (Expenses)

		Three months ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Crude Oil	($,000)	**($347)**	($1,567)	-78%	**($1,400)**	($1,498)	-7%
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$0	-	**$0**	($20)	-100%
Hedging Revenues (Expenses)	**($,000)**	**($347)**	**($1,567)**	**-78%**	**($1,052)**	**($3)**	**40321%**
Hedging Revenues (Expenses)	($/BOE)	**($0.81)**	($5.68)		**($288.03)**	$0.65	

- Lonestar realized crude oil hedge expense of $0.3 million in the third quarter of 2014 vs. a crude oil hedge income of $0.05 million reported in the third quarter of 2013.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	73,600	Oct 1, 2014	-	Dec 31, 2014	WTI	$93.90	-	-	Swap
Crude Oil	24,700	Oct 1, 2014	-	Dec 31, 2014	WTI	$90.70	-	-	Swap
Crude Oil	5,700	Oct 1, 2014	-	Dec 31, 2014	WTI	$94.00	-	-	Swap
Crude Oil	43,100	Nov 1, 2014	-	Dec 31, 2014	WTI	$101.38	-	-	Swap
Crude Oil	27,000	Oct 1, 2014	-	Dec 31, 2014	LLS	$97.00	-	-	Swap
Crude Oil	46,000	Oct 1, 2014	-	Dec 31, 2014	LLS	$93.20	-	-	Swap
Crude Oil	244,200	Jan 1, 2015	-	Dec 31, 2015	WTI	$87.00	-	-	Swap
Crude Oil	255,500	Jan 1, 2015	-	Dec 31, 2015	WTI	$81.25	-	-	Swap
Crude Oil	35,460	Jan 1, 2015	-	Mar 31, 2015	WTI	$92.10	-	-	Swap
Crude Oil	63,400	Jan 1, 2015	-	Mar 31, 2015	WTI	$98.15	-	-	Swap
Crude Oil	32,942	Apr 1, 2015	-	Jun 30, 2015	WTI	$90.40	-	-	Swap
Crude Oil	55,300	Apr 1, 2015	-	Jun 30, 2015	WTI	$95.65	-	-	Swap
Crude Oil	32,016	Jul 1, 2015	-	Sep 30, 2015	WTI	$88.87	-	-	Swap
Crude Oil	49,700	Jul 1, 2015	-	Sep 30, 2015	WTI	$93.65	-	-	Swap
Crude Oil	29,992	Oct 1, 2015	-	Dec 31, 2015	WTI	$87.80	-	-	Swap
Crude Oil	45,500	Oct 1, 2015	-	Dec 31, 2015	WTI	$92.25	-	-	Swap
Crude Oil	35,800	Jan 1, 2015	-	Mar 31, 2015	WTI	$91.60	-	-	Swap
Crude Oil	31,400	Apr 1, 2015	-	Jun 30, 2015	WTI	$89.50	-	-	Swap
Crude Oil	205,000	Jan 1, 2016	-	Dec 31, 2016	WTI	$84.45	-	-	Swap
Crude Oil	309,000	Jan 1, 2016	-	Dec 31, 2016	WTI	$90.45	-	-	Swap

Lonestar continues to be an active participant in the commodity derivatives market as a tool to manage commodity price risk, create higher certainty of returns on capital expenditures, and maximize its borrowings available under its Credit Facilities. As the Company places new wells into production, it expects to enter into additional derivatives transactions to further hedge the Company from the risks associated with the oil and gas business. Accordingly, since the end of the third quarter of 2014, the Company entered into additional WTI Crude Oil hedge contracts totaling 255,500 barrels in 2015 placed monthly for an average strike price of $81.25 per barrel.

Non-recurring Expense

Lonestar recorded $0.4 million of regulatory mandated P&A and severance expenses during the third quarter of 2014. This charge has been excluded from the Company's EBITDAX calculation.

All figures are unaudited. All figures are in US dollars unless noted otherwise

LONESTAR
RESOURCES

UNAUDITED INTERIM FINANCIAL REPORT

For the three months ended September 30, 2014

Consolidated statements of comprehensive income

For the three and nine months ended September 30, 2014 and 2013

(US $,000)	*As Reported* Three months ended September 30,		*As Reported* Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues (Net of Royalties)				
Crude Oil	28,781	20,757	76,440	48,807
Natural Gas Liquids	1,422	782	3,564	1,758
Natural Gas	2,095	1,268	5,571	5,122
Revenues (Net of Royalties)	**32,299**	**22,808**	**85,575**	**55,687**
Hedge Revenues (Expenses)	(347)	(1,567)	(3,269)	(1,518)
Net Revenue From Ordinary Activities	**31,951**	**21,241**	**82,306**	**54,168**
Operating Expenses				
Lease Operating Expenses	(4,383)	(3,247)	(11,680)	(9,332)
Severance Taxes	(1,512)	(994)	(3,993)	(2,295)
Ad Valorem Taxes	(497)	(373)	(1,359)	(1,424)
Depreciation, Depletion & Amortization	(9,217)	(7,767)	(26,755)	(19,220)
General & Administrative	(2,187)	(1,590)	(6,050)	(5,789)
Total Operating Expenses	**(17,797)**	**(13,971)**	**(49,837)**	**(38,059)**
Gross Profit from Operating Activities	**14,154**	**7,270**	**32,469**	**16,109**
Other Income (Expense)	**(44)**	**(21)**	**419**	**12,763**
Stock based compensation	**(627)**	**0**	**(1,962)**	**(170)**
Non-recurring expenses	**(449)**	**0**	**(1,563)**	**0**
Interest & Other Finance Expenses	**(5,348)**	**(1,118)**	**(14,241)**	**(2,429)**
Fair Value Gain (Loss) on derivatives	**12,954**	**(4,538)**	**4,630**	**(2,084)**
Profit (Loss) before taxes	**20,641**	**1,594**	**19,752**	**24,189**
Income tax (expense) benefit	**(1,508)**	**(22)**	**(2,550)**	**(1,083)**
Net Income (Loss)	**19,132**	**1,572**	**17,202**	**23,106**
EBITDAX	**23,371**	**15,037**	**59,224**	**35,329**

All figures are unaudited. All figures are in US dollars unless noted otherwise

Consolidated statements of financial position
As of September 30, 2014

(US $,000)		*As Reported* As of	
	September 30, 2014	June 30, 2014	December 31, 2013
Assets			
Current Assets			
Cash and cash equivalents	13,922	13,498	6,744
Trade and other receivables	15,418	18,196	7,823
Derivative financial instruments	2,874	33	157
Other assets	1,430	932	507
Total current assets	**33,645**	**32,659**	**15,231**
Non-current assets			
Oil and Gas Properties & Equipment	445,350	410,117	293,478
Deferred tax assets	79	81	43,175
Derivative financial instruments	1,087	10	490
Other non-current assets	4,034	4,307	2,157
Total non-current assets	**450,550**	**414,515**	**339,299**
Total Assets	**484,196**	**447,174**	**354,530**
Liabilities			
Current liabilities			
Trade and other payables	30,663	14,961	9,197
Revenue payable	6,058	3,150	4,087
Accrued expenses	1,857	16,906	2,067
Derivative financial instruments	213	7,277	-
Total current liabilities	**38,791**	**42,294**	**15,351**
Non-current liabilities			
Long-term Debt	237,332	215,051	109,000
Deferred tax liablilities	11,649	10,136	53,280
Other non-current liabilities	7,863	10,881	9,195
Total non-current liabilities	**256,845**	**236,068**	**171,475**
Total Liabilities	**295,636**	**278,362**	**186,826**
Net assets	**188,560**	**168,812**	**167,704**
Equity			
Contributed equity	142,638	142,638	142,638
Reserves	7,034	8,770	4,450
Retained Earnings	38,888	17,404	20,616
Total Equity	**188,560**	**168,812**	**167,704**

All figures are unaudited. All figures are in US dollars unless noted otherwise

Consolidated statements of cash flows
As of September 30, 2014

(US $,000)	*As Reported* Three Months Ending September 30, 2014	Nine Months Ending September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Profit/(loss) for the year	19,133	17,202
Adjustments to reconcile profit/(loss) to net cash	-	-
provided by operating activities:	-	-
Gain on sale of oil and gas properties	-	(466)
Depreciation, depletion, amortisation	9,217	26,612
Increase in retirement provision	-	143
Deferred taxes	1,516	3,213
Share based payments	627	1,962
Non-cash interest expense	275	550
Changes in operating assets and liabilities:	-	-
Accounts receivable	2,777	(7,502)
Other assets	(226)	(2,932)
Accounts payable and provisions	3,554	22,210
Net cash inflow from operating activities	36,873	60,992
CASH FLOWS FROM INVESTING ACTIVITIES		
Payments for oil and gas property, plant & equipment	(44,475)	(108,017)
Acquisition of oil and gas properties	-	(70,978)
Net (increase) decrease in derivatives	(13,974)	(5,489)
Proceeds from sales of oil and gas properties	-	3,200
Net cash (outflow) from investing activities	(58,449)	(181,284)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net change in borrowings	22,000	(87,030)
Proceeds from issuance of long term bonds	-	214,500
Net cash inflow from financing activities	22,000	127,470
Net increase in cash held	424	7,178
Cash and cash equivalents at the beginning of the financial period	13,498	6,744
Cash and cash equivalents at the end of the financial period	13,922	13,922

All figures are unaudited. All figures are in US dollars unless noted otherwise

Notes to the Quarterly Report

CY14 EBITDAX guidance is based on the following assumptions:

- Oil prices and gas prices are based on a NYMEX futures pricing scenario as set out in the table below. Pricing adjustments are made to these prices for individual assets to account for quality, transportation fees, marketing bonuses and regional price differentials.

Year	Oil (US$/bbl)	Gas (US$/MMBtu)
2014	$95.25	$4.38

- The total number of planned wells at each asset is consistent with assumptions contained in the respective reserve assessments.
- The estimated well drilling and completion capital expenditures are based on the most recent Authorizations for Expenditures at each asset.
- Operating expenditures for each asset are based on the Company's most current forecast for lease operating expenses for each asset.

Cautionary and Forward Looking Statements

Lonestar has presented petroleum and natural gas production and reserve volumes in barrel of oil equivalent ("boe") amounts. For purposes of computing such units, a conversion rate of 6,000 cubic feet of natural gas to one barrel of oil equivalent (6:1) is used. The conversion ratio of 6:1 is based on an energy equivalency conversion method which is primarily applicable at the burner tip and does not represent value equivalence at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation.

Statements in this press release which reflect management's expectation relating to target dates, expected drilling program, and the ability to fund its development plans are forward-looking statements, and can be generally be identified by words such as "will", "expects", "intends", "believes", "estimates", "anticipates", "projects" or similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Statements relating to "reserves" are deemed to be forward looking statements as they involve the implied assessment, based on certain estimates and assumptions that that some or all of the reserves described can be profitably produced in the future. These statements are not historical facts but instead represent the expectations of management and/or its independent petroleum consultants, regarding future events.

Although management believes the expectations reflected in such forward-looking statements are reasonable, forward-looking statements are based on the opinions, assumptions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include risks related to exploration, development and production; oil and gas prices, markets and marketing; acquisitions and dispositions; competition; additional funding requirements; changes in access to and the costs of energy services; reserve estimates being inherently uncertain; incorrect assessments of the value of acquisitions and exploration and development programs; environmental concerns; reliance on key personnel; title to assets; expiration of leases; hedging activities; litigation; government policies; unforeseen expenses; and contractual risk. Additionally, if any of the assumptions or estimates made by management prove to be incorrect, actual results and developments are likely to differ, and may differ materially, from those expressed or implied by the forward-looking statements contained in this document. Such assumptions include, but are not limited to, general economic, market and business conditions and corporate strategy. Accordingly, investors are cautioned not to place undue reliance on such statements.

All of the forward-looking information in this press release is expressly qualified by these cautionary statements. Forward-looking information contained herein is made as of the date of this document and Lonestar disclaims any obligation to update and forward-looking information, whether as a result of new information, future events or results or otherwise, expect as required by law.

Reserves Reporting:

Pursuant to ASX Listing Rules ("LR") the reserves information in this document:

(i) is effective as at 1 January, 2014 (LR 5.25.1)
(ii) has been estimated and is classified in accordance with SPE-PRMS (Society of Petroleum Engineers - Petroleum Resources Management System) (LR 5.25.2)
(iii) is reported according to the Company's economic interest in each of the reserves and net of royalties (LR 5.25.5)
(iv) has been estimated and prepared using the deterministic method (LR 5.25.6)
(v) has been estimated using a 6:1 BOE conversion ratio for gas to oil, pursuant to the information in the disclaimer section of this document (LR 5.25.7)

Other Reserves Information:

Lonestar operates most of its properties which are generally held by standard oil and gas lease arrangements. Detailed information on the operator and lease arrangements is generally disclosed in the Company announcement related to the initial acquisition of the properties. The Company's working interest ownership (WI%) and net-revenue interest ownership (NRI%) in relation to each of its properties are generally included in the Company's presentations which are available on the ASX or the Company's websites. Well spacing assumptions and lateral length assumptions are generally included in the Company's presentations as is additional information on capital cost and taxation assumptions.

Qualified Petroleum Reserves and Resources Evaluators:

In accordance with ASX Listing Rules 5.41 and 5.42:

The reserve reporting provided in this document in relation to the Company's Eagle Ford Shale properties is based on and fairly represents information and supporting documentation that has been prepared by Mr. William D. Von Gonten, Jr., P.E., and Mr. Taylor D. Matthes, P.E. who are employed by W. D. Von Gonten & Co Petroleum Engineering. Mr. Von Gonten holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and Mr. Matthes holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University. Both of these persons are Registered Texas Professional Engineers. Mr. Von Gonten has 24 years of experience as a Petroleum Engineer and Mr. Matthes has more than 5 years of experience as a Petroleum Engineer. Both of these persons are members of the Society of Petroleum Engineers . Messrs. Von Gonten and Matthes have consented to the inclusion in this document of the information and context in which it appears.

The reserve reporting provided in this document in relation to the Company's Conventional properties is based on and fairly represents information and supporting documentation that has been prepared by Mr. William M. Kazmann who is President and Senior Partner La Roche Petroleum Consultants, Ltd. Mr. Kazmann received his Bachelor of Science and Master of Science degrees in Petroleum Engineering from the University of Texas at Austin in 1973 and 1975 respectively. He has worked in the oil and gas industry since that time. Mr. Kazmann is a Licensed Professional Engineer in the State of Texas and is a member of the American Association of Petroleum Geologists, Society of Petroleum Engineers, Society of Independent Professional Earth Scientists (serving as National Director from 1993 to 1996 and National Treasurer in 1994 and 1995), Dallas Geological Society, and Dallas Petroleum Club (serving as Director from 2004 through 2006). Mr. Kazmann has consented to the inclusion in this document of the information and context in which it appears.

Reserves Cautionary Statement:

Hydrocarbon reserves and resource estimates are expressions of judgment based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. The may result in alterations to development and production plans which may, in turn, adversely impact the Company's operations. Reserves estimates and estimates of future earnings are, by nature, forward looking statements and subject to the same risks as other forward looking statements.

Commodity Pricing Used:

Lonestar's reserves and PV-10 have bee estimated using index prices determined in accordance with US SEC pricing guidelines for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the lift of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the year ended December 31, 2013 were $96.94 per bbl for oil and $3.66 per mmbtu for natural gas and for the year ended December 31, 2012 were $95.05 bbl for oil and $2.78 per mmbtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead."