Quarterly Report

June 2014

LONESTAR RESOURCES

Lonestar Resources, Ltd. (ASX:LNR, OTCQX: LNREF) is pleased to provide an update on its financial and operational results for the three months ended June 30, 2014 (2Q14).

Second Quarter Highlights

- Lonestar reported a 34% increase in oil and gas production to 3,613 BOEPD (net of royalties) in 2Q14, vs. 2,691 BOEPD in 2Q13, 83% of which was crude oil and NGL's.
- Net Revenues From Ordinary Activities increased 39% to US$24.7 million for 2Q14, vs. 2Q13 revenues of $17. 8 million.
- EBITDAX increased 46% to $16.7 million for 2Q14 vs. $11.5 million for 2Q13.
- Net Loss was $7.0 million for 2Q14 vs. net income of $14.6 million reported for 2Q13. Included in this net loss was a total of $7.6 million of charges relates to unrealized, mark-to-market hedging losses, non-recurring P&A expense and stock based compensation.
- Lonestar spent $28.4 million to drill and complete 5 Eagle Ford Shale wells during the quarter. Flowback on each of the 3 Beall Ranch wells commenced in late June, providing minimal impact on the 2Q14 results. Flowback on the each of the 2 Pirate wells commenced mid July, providing no impact to 2Q14.
- Oil & gas sales in the third quarter of 2014 are expected to benefit incrementally from 2 recent completions at Pirate and 3 recent completions at Beall Ranch. Lonestar's current production is averaging 5,005 BOEPD. Lonestar also expects contribution from its first 2 wells in Brazos County, which it has recently cased and expects to frac in August.
- 2Q14 also saw Lonestar make material progress in its corporate objectives:
  - Lonestar acquired or reached agreement to acquire an additional 3,138 gross / 2,418 net acres in its core areas of the Eagle Ford Shale, increasing our Eagle Ford position to 25,497 net acres. Total costs associated with the acquisitions is $7.0 million, or $2,887 per net acre. Lonestar is also in final negotiations on an additional 5,000 net acres which hold an estimated 39 gross / 34 net drilling locations.
  - Based on current rates of production and its current capital plans, Lonestar sees a 2014 exit rate of 6,500 to 7,000 BOEPD, and reiterates its 2014 EBITDAX guidance of $105 to $125 million.
  - Lonestar's current drilling budget of $135 million in 2015 is expected to increase 2015 production by 30-50% and 2015 EBITDAX by 40-60%, compared to 2014 at current prices.

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Management's Discussion and Analysis

Lonestar Resources, Ltd. is pleased to announce its operational and unaudited financial results for the quarter ended June 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 100% of its activities 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 50,000 acre leasehold (32,600 net acres) and tested light oil from the Bakken, Three Forks and Lower Lodgepole formations.

SECOND QUARTER 2014 HIGHLIGHTS

Corporate

- Since its last report, Lonestar has made a series of additional lease acquisitions which add a total of 3,138 gross / 2,418 net acres in its existing areas of focus in the Eagle Ford Shale Trend. These transactions expand Lonestar's leasehold by 10% to 29,002 gross / 25,497 net acres in the Eagle Ford Shale play (average working interest of 87.9%). The total consideration associated with these leasehold additions is $7.0 million, or an average of $2,887 per net acre. 1,880 net acres were acquired under primary term leases at a total cost of $3.5 million ($1,872 per net acre) and another 539 net acres are being acquired in the form of farm-ins, with an estimated $3.4 million of drilling carries being employed to gain access to those leases, with these funds being spent over time. By region:
  - Western Region- Lonestar has added 1,755 gross / 1,035 net acres, increasing its position in the Western Region by 15% to current levels of 10,320 gross / 8,108 net acres. The total consideration associated with these leasehold additions is $3.2 million, or an average of $3,043 per net acre.
  - Central Region- Lonestar has added 546 gross / 546 net acres, increasing its position in the Central Region by 5% to current levels of 11,587 gross / 11,530 net acres. The total consideration associated with these leasehold additions is $1.8 million, or an average of $3,334 per net acre.
  - Eastern Region- Lonestar has added 6,050 gross / 5,855 net acres, increasing its position in the Eastern Region by 17% to current levels of 7,097 gross / 5,859 net acres. The total consideration associated with these leasehold additions is $2.0 million, or an average of $2,404 per net acre.
- Lonestar is also in final negotiations on an additional 5,000 net acres which holds an estimated 39 gross / 34 net drilling locations.
- These leasehold acquisitions will be funded via the Company's $108.5 million revolving credit facility, which was undrawn and fully available at the end of the second quarter.
- Lonestar internally estimates these leasehold acquisitions, in combination with the positive effects of offset drilling activity near its 'Upside' Acreage in Central Brazos County increase the Company's drilling inventory by 47 gross / 30 net locations. The Company intends to submit these locations to its independent engineers as part of its annual reserves estimation process. These locations serve to deepen the Company's inventory and should allow it to continue to high-grade its long-term drilling program. It continues to be Lonestar's plan is to complete an average of 21 wells per annum at a current projected cost of $135 million.. This budget is intended to be funded out of cash flow in 2015 and beyond.
- Lonestar continues to rationalize its asset portfolio towards intensifying its focus on the Eagle Ford Shale Trend. Effective June 1, 2014, the Company sold its non-operated Raccoon Bend property in south Texas for $3.2 million. Recent production from this asset averaged 50 BOEPD of low-margin production, and at the time of sale, Proved Reserves were estimated at 244,000 BOE. The proceeds of this sale were used to partially fund the acquisition of Eagle Ford leasehold highlighted above.

Operational

- Lonestar's net production for the second quarter of 2014 averaged 3,613 BOE per day, and was comprised of 2,668 barrels of oil per day, 333 barrels of NGL's per day, and 3,668 Mcf of natural gas per day. 2Q14 production levels were up 34% over 2Q13 levels, which included 308 BOEPD from properties which it has since sold (Barnett Shale, Oklahoma, Louisiana, and Raccoon Bend). Lonestar also sold non-operated Conventional asset (Raccoon Bend) effective June 1st, 2014 which produced 73 BOE per day in the prior period.
- Lonestar's 2Q14 net production actually declined 5% from 1Q14 levels due to production disruptions related to fracture stimulation activities in the Western Region, which prevented much higher reported rates from occurring in 2Q14. These disruptions occurred at Asherton and Beall Ranch, and combined to negatively affect 2Q14 by an average of 421 BOEPD for the second quarter as a whole. These disruptions, which are commented on in detail in the Operations Review below, have now all been satisfactorily resolved and Lonestar currently believes there is no impact to long-term recoverable reserves.
- With the recent addition of the Company's 2 new Pirate wells, recovery in production from legacy producers at Beall Ranch and Asherton, and the addition of 3 new short laterals at Beall Ranch, the Company estimates that current production rates are averaging 5,005 BOEPD.

Operations Review

EAGLE FORD SHALE TREND- WESTERN REGION

- **Asherton-** In central Dimmit County, Lonestar drilled and completed the #9HS with a perforated interval of 5,044' and the #10HN with a perforated interval of 5,151'. The wells were turned to the tanks at an average cost of $5.2 million vs. our AFE of $5.5 million and placed into flowback in late March. The #9HS well registered an IP of 507 BOEPD and a Max-30 rate of 440 BOEPD (16/64" choke) while current rates are 298 gross/ 221 net BOEPD after 136 days online. The #10HN well registered an IP of 333 BOEPD and a Max-30 rate of 248 BOEPD (16/64" choke) while current rates are 194 gross / 143 net BOEPD after 133 days online. In June, we determined that the #10HN was impaired by sand in the wellbore, which has been removed, and the #10HN continues to gradually increase in terms of rate. In aggregate, these 2 new wells are performing in-line with our Type Curve. Unfortunately, the two legacy producers at Asherton, the #2HN and #6HS, went offline when frac operations from the #9HS and #10HN were conducted, after loading up with frac fluids, and to a lesser extent, sand. In total, these 2 legacy producers were offline for 39 of the 91 days during the second quarter, impairing production by an average of 259 gross / 213 net BOEPD during the quarter. Cleanout efforts on these 2 legacy wells have been successful, and these 2 wells are together contributing 323 gross / 239 net BOEPD currently, which is in-line with rates the 2 wells were registering in January, 2014. Oil production rates on the 2 legacy wells have fully recovered, while natural gas production rates continue to climb steadily as load water rates diminish.
- **Beall Ranch-** In Dimmit and La Salle Counties, Lonestar completed the drilling and completion of the #32H, #33H and #34H wells. Fracture stimulations were completed on May 24, and after 21 days of 'soak time', flowback on these 3 wells commenced on June 15.The costs incurred for drilling and completing these three 3,900' laterals averaged $4.5 million versus our pre-drill AFE of $5.0 million per well, in spite of opting to employ more expensive resin-coated 20/40 sand in the tails of our frac stages. On average, these 3 short laterals registered an IP of 379 BOEPD and a Max-30 rate of 318 BOEPD (16/64" choke) while current rates are 333 gross / 240 net BOEPD after 46 days online. These wells are performing in accordance with Lonestar's expectations for wells on which it exercises choke management. Moreover, these 'short' laterals were drilled and completed for 10% less than budgeted, and should generate outstanding Internal Rates of Return. Similar to the experience the Company had at Asherton, even after standard shut-in to build pressure in anticipation of ensuing frac jobs, several of the wells that offset Lonestar's recent frac operations on its #32H, #33H, #34H wells were taken offline due to the impact of these frac jobs. The wells most directly impacted by these fracs were the #8H and #9H, which directly offset the newly fracked wells to the east. However, all 5 of the Company's wells drilled on its D Pad were negatively impacted by the new frac jobs. In total, Lonestar estimates that deferred production from these wells negatively impacted its 2Q14 results by an average of 284 BOEPD gross / 208 net BOEPD. Post-event evaluation has led Lonestar to conclude that the D pad wells were uniquely impacted because they were the only wells at Beall Ranch in which resin-coated sand was not employed. Historically, Lonestar had seen no frac sand production on its older generation wells, nor had it seen any production interference between wells, and therefore elected to eliminate tailing in with resin-coated sand on more recent wells. In response to recent experience at Asherton and Beall Ranch, Lonestar was able to resume the practice of pumping resin-coated sand on its newly fracked wells and anticipates that this step will prevent production impairment in future frac jobs from offset wells drilled in the future. Of high importance is that Lonestar believes that all of the impacted wells have been returned to production without any long-term impact to productivity or reserves recovery. During the first week of May, 2014, prior to shut-ins related to the 3 frac jobs, Lonestar's 14 legacy producers averaged 2,324 gross / 1,703 net BOEPD. Strong evidence that these wells have been fully returned to service lies in the fact that production for the week ended July 28th, these same 14 legacy producers averaged 2,224 gross / 1,630 net BOEPD with oil volumes equivalent to prior levels and gas production recovering as water production falls off.
- **Burns Ranch Area-** On July 4th , 2014, Lonestar commenced drilling operations on the Meiners #1H, #2H and #3H wells, on leases acquired in the Clayton Williams transaction in La Salle County. These 3 wells, with projected TD's of 13,486 feet and estimated perforated intervals of 4,670' are AFE'd at an average of $6.2 million. The Company has cased the second of the 3 wells, and thus far, drilling pace has been faster than expected, reaching total depth in 10 and 11 days, respectively versus AFE of 14 days. These wells are currently scheduled for fracture stimulation in late-August, 2014 and are expected to contribute incremental volumes in late September or early October.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, Lonestar completed the #A-3H with a perforated interval of 5,951'. The well was turned to the tanks at a cost of $7.8 million and placed into flowback in early April. On April 8, 2014, the #A-3H tested at a rate of 182 BOEPD, (16/64" choke). Lonestar has recently installed an ESP on this well, and production rates are averaging 130 BOEPD after 4 months onstream. Lonestar completed the #B-1H with a perforated interval of 5,910'. The well was turned to the tanks at a cost of $7.2 million and placed into flowback in early April. The Max IP for the #B-1H well was 350 BOEPD, (16/64" choke), and the well recently produced rates of 258 BOEPD after 4 months on production. While the early rates were under our Type Curve, Lonestar is evolving its artificial lift strategies, and these 2 wells appear to be capable of producing at stable rates for an extended period of time. Lonestar is pleased with the results achieved to date on its first 2 wells at Pirate. Importantly, Lonestar believes that its second two completions in southwest Wilson County demonstrate the value of its measured approach to development, and its ability to materially improve well costs and productivity.

- **Pirate Area (continued)**- On July 16, 2014 Lonestar commenced flowback operations on the Pirate #K1H and #L3H wells. Despite being with an average perforated interval of 7,472 feet (which is 26% longer in terms of perforated interval than Lonestar's first 2 wells in the Pirate Area) Lonestar's second generation Pirate wells were placed onstream at a lower completed well cost ($7.4 million) than the Company's first 2 wells in the Pirate Area, and in-line with its pre-drill AFE. Importantly, Lonestar's 2 new wells at Pirate are materially more productive than its first 2 wells. The Pirate #K1H has registered an average rate of 304 gross / 237 net BOEPD over the last 7 days while the Pirate #L1H has registered an average rate of 429 gross / 335 net BOEPD over the last 7 days. Lonestar is particularly encouraged that these oil flow rates are being achieved while the oil cuts have not yet reached 40%, as these wells have only registered 14 days of total flowback time.
- **Southern Gonzales County**- During the second quarter, Lonestar entered into a farm-in agreement with an independent oil company covering 972.11 net acres in southern Gonzales County. The independent oil company was attracted to Lonestar due its operational capabilities, and its ability to quickly move to spud wells on the leasehold. Lonestar is attracted to the area in that it has proven to be a deeper, highly prolific sector of the crude oil window. EOG has drilled 23 Eagle Ford Shale producers on leases that are contiguous to this block at an average depth of 10,000 feet with an average crude oil gravity of 40 degrees API. Most impressive is that initial oil production from these 23 wells as reported to the Texas Railroad Commission ranged from 562 boepd to 2,810 bopd. In return for a small carried interest in the drilling and completion costs, Lonestar will earn a 50% working interest in each well that it drills on this block. The parties plan to drill between 1 and 3 wells on this leasehold in the third quarter of 2014, with an eye to move in frac crews onto the lease in late October, 2014. Estimated drilling and completion costs for these 6,500 foot laterals is $7.6 million. An election on well count will be made in the next 14 days. Lonestar believes that over time, as many as 9 laterals can be drilled on this lease. To capture this opportunity, Lonestar shuffled its drilling schedule, deferring 2 wells it had previously planned to drill on leasehold in either its Western or Eastern Region. This flexibility is important to the Company's ability to continue to add high-quality leases to its opportunity set. This shuffling of the schedule ultimately deferred the timing of completion of certain of the Company's other planned wells for 2014, modestly deferring its production ramp-up, but is expected to enhance 2015 production rates.

EAGLE FORD SHALE TREND- EASTERN REGION

- **'Engineered' Acreage**- In Northern Brazos and Southern Robertson Counties, Lonestar has 25 drilling locations to which its independent petroleum engineers have assigned reserves, which lie within the confines of densely drilled portions of Brazos and Robertson County. Lonestar is pleased to report that it is making excellent progress on its drilling, completion and lease acquisition program. Lonestar completed the Ranger Dansby #A4H (5,957' lateral). After a sidetrack operation, the well reached total depth in 23 days, 4 days longer than AFE. Taking lessons learned from its first well, Lonestar reached total depth on Ranger Dansby #B1H (5,650' lateral) in 12 days, 7 days under AFE. These wells have been cased and are scheduled to be fracked in mid-August. Lonestar currently has 5 additional locations engineered on the Ranger Dansby lease block, which were designated Possible in its third party reserve report at December 31, 2013. Based on its activities and that of offset operators, Lonestar expects significant revisions to Proved Reserves on this block at year-end 2014. The Company has firm plans to drill 3 additional wells during 2014 in the Eastern Region. Lonestar anticipates spudding the Dunn A Unit #1H on Friday, August 1st and will drill a second well on this unit. Each of these wells are AFE'd for lateral lengths of 6,900 feet. Lonestar will operate these wells with approximately 76% working interest, with Halcon Resources owning the remaining working interest. These wells, which are expected to contribute to 4Q14 production, are currently classified as Probable in the Company's reserve report. Lonestar then plans to spud the Scasta #2H, a Proved Undeveloped location, where the drill pad, drilling permit, and production facilities are already in-place.
- **'Upside' Acreage**- In response to a significant southward expansion in the productive limits of the Eagle Ford Shale play in Brazos and Burleson County, Lonestar has initially focused its incremental leasing efforts towards augmenting the number of drillable locations on its existing leasehold positions where the top of Eagle Ford ranges from 8,300 and 10,100 feet, where the industry has drilled wells with impressive initial flow rates, and has accelerated drilling activity based on those results. Generally speaking, these deeper wells have translated into materially higher early production rates when compared to wells drilled between 6,500 and 7,500', where Lonestar's Engineered locations lie, and the bulk of industry activity is occurring. In the last 4 months, a number of important wells have provided evidence of high productivity in the deeper section of the Eagle Ford Shale. Publicly available data includes several highly productive Eagle Ford wells such as the Apache McCullough-Wineman #2H (1,201 BOEPD, Top EFS 10,120'), the Halcon Jones #2H (783 BOEPD, Top EFS 8,800') and the Halcon Stifflemire #1H (661 BOEPD, Top EFS 8,300') and the Comstock Henry #A1H (1,267 bopd test, Top EFS 9,514') which have substantially expanded the known productive limits of the Eastern Eagle Ford. Lonestar believes that it is increasingly well positioned in this deeper section of the Eastern Eagle Ford. Upon close of its Clayton Williams acquisition, Lonestar held 2,109 gross / 1,385 net acres at these depths, which it had not submitted for engineering, and currently has no reserves booked. Through primary term leasing, Lonestar has leased or committed to lease an additional 483 gross / 301 net acres at these depths in leases adjacent to its existing lease blocks at a total cost of $358,000, or $1,190 per net acre. While certain issues remain outstanding, Lonestar believes that it has sufficient acreage to drill approximately 22 gross / 16 net drilling locations at these depths, and that these locations represent material reserves upside for the Company, some of which may be booked at year-end 2014. Currently, industry is drilling 7 wells which offset Lonestar's Upside Acreage. Lonestar will observe the results of these wells with an eye towards drilling at least 2 wells at these depths in 2015.

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. In March, Lonestar (65% WI) and its partners completed the acquisition and processing of 105 square miles of 3-D seismic data covering the Poplar West project area. Lonestar and its partners have interpreted the 3-D seismic data and conventional and unconventional prospects are being mapped. Lonestar expects this process to be complete at the end of August, and will then bring in a farm-in partner. 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 in the third quarter of 2014. 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.

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 a range of 19-25 wells, which is intended to result in the drilling and completion of 21 wells during the calendar year, and also reflect the fact that the Company will continue to maintain some discretion as to the actual location of those wells. 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.
- **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 expects to place these wells online in September. Lonestar expects to complete and frac 3 wells in La Salle County (Meiners) on leases acquired from Clayton Williams by early September, with flowback commencing in late September or early October. Lonestar expects to drill 1-3 50% WI wells on a farm-in in southern Gonzales County.
- **4Q14**- During the fourth quarter, Lonestar plans to frac place onstream 3 additional wells in Brazos and Robertson Counties (2 76.7% WI wells at Dunn and 1 100% WI well at Scasta). The 1-3 wells it plans to drill in southern Gonzales County are scheduled to be fracked in late October, with production scheduled for mid-November, 2014. If Lonestar limits its program in southern Gonzales County to 1 well, it has 3 drilling locations in LaSalle County prepared to move to immediately. If Lonestar drills all 3 wells in Gonzales County, the 3 drilling locations in LaSalle County will be deferred into early 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	0 - 0	3 - 6	3 - 6
Western Eagle Ford	**2 - 2**	**3 - 3**	**0 - 0**	**3 - 6**	**8 - 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	1 - 3	1 - 3
Central Eagle Ford	**3 3**	**0 - 0**	**2 - 2**	**1 - 3**	**6 8**
Eastern Eagle Ford					
Brazos County	0 - 0	0 - 0	2 - 2	1 - 2	3 - 4
Robertson County	0 - 0	0 - 0	0 - 0	2 - 2	2 - 2
Eastern Eagle Ford	**0 - 0**	**0 - 0**	**2 - 2**	**3 - 4**	**5 - 6**
TOTAL EAGLE FORD	**5 - 5**	**3 - 3**	**4 - 4**	**7 - 13**	**19 - 25**

Management's Discussion and Analysis

Net Production (after royalties)

		Three months ended June 30,			Six Months Ended June 30,		
		2014	2013	% Change	2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	(bbls/day)	**1,546**	1,174	*32%*	**1,651**	999	*65%*
Natural Gas Liquids	(bbls/day)	**319**	258	*23%*	**344**	195	*77%*
Natural Gas	(Mcf/day)	**2,623**	1,569	*67%*	**2,681**	1,382	*94%*
Oil Equivalent	**(BOE/day)**	**2,301**	**1,694**	***36%***	**2,443**	**1,425**	***71%***
Central Eagle Ford Shale							
Crude Oil	(bbls/day)	**497**	-	-	**416**	-	-
Natural Gas Liquids	(bbls/day)	**-**	-	-	**-**	-	-
Natural Gas	(Mcf/day)	**-**	-	-	**0**	-	-
Oil Equivalent	**(BOE/day)**	**497**	**-**	**-**	**416**	**-**	**-**
Eastern Eagle Ford Shale							
Crude Oil	(bbls/day)	**181**	-	-	**183**	-	-
Natural Gas Liquids	(bbls/day)	**12**	-	-	**11**	-	-
Natural Gas	(Mcf/day)	**94**	-	-	**74**	-	-
Oil Equivalent	**(BOE/day)**	**209**	**-**	**-**	**206**	**-**	**-**
Total Eagle Ford Shale							
Crude Oil	(bbls/day)	**2,224**	1,174	*89%*	**2,250**	999	*125%*
Natural Gas Liquids	(bbls/day)	**331**	258	*28%*	**355**	195	*82%*
Natural Gas	(Mcf/day)	**2,717**	1,569	*73%*	**2,755**	1,382	*99%*
Oil Equivalent	**(BOE/day)**	**3,008**	**1,694**	***78%***	**3,064**	**1,425**	***115%***
Barnett Shale							
Crude Oil	(bbls/day)	**-**	-	-	**-**	-	-
Natural Gas Liquids	(bbls/day)	**-**	-	-	**-**	-	-
Natural Gas	(Mcf/day)	**-**	1,247	*-100%*	**-**	2,467	*-100%*
Oil Equivalent	**(BOE/day)**	**-**	**208**	***-100%***	**-**	**411**	***-100%***
Conventional							
Crude Oil	(bbls/day)	**445**	570	*-22%*	**474**	587	*-19%*
Natural Gas Liquids	(bbls/day)	**2**	9	*-78%*	**3**	5	*-37%*
Natural Gas	(Mcf/day)	**951**	1,258	*-24%*	**984**	1,329	*-26%*
Oil Equivalent	**(BOE/day)**	**605**	**789**	***-23%***	**641**	**813**	***-21%***
Total Company							
Crude Oil	(bbls/day)	**2,668**	1,744	*53%*	**2,725**	1,586	*72%*
Natural Gas Liquids	(bbls/day)	**333**	268	*25%*	**358**	200	*79%*
Natural Gas	(Mcf/day)	**3,668**	4,074	*-10%*	**3,739**	5,178	*-28%*
Oil Equivalent	**(BOE/day)**	**3,613**	**2,691**	***34%***	**3,706**	**2,649**	***40%***

Lonestar's net production for the second quarter of 2014 averaged 3,613 BOE per day, and was comprised of 2,668 barrels of oil per day, 333 barrels of NGL's per day, and 3,668 Mcf of natural gas per day. 2Q14 production rose 34% over rates reported in 2Q13. The quarter was negatively impacted by frac-related outages on its legacy wells at Beall Ranch and Asherton. The Company calculates these outages averaged 421 BOEPD during the second quarter. Production was also reduced by 27 BOEPD from the June sale of its non-operated Raccoon Bend asset. Second quarter production benefited from the Company's first 2 wells at Pirate, and the commencement of flow back on its Beall Ranch #32H, 33H and 33H wells in late June.

- Lonestar's net production from its Eagle Ford Shale assets averaged a 3,008 BOE per day during the second quarter of 2014, and was comprised of 2,224 barrels of oil per day, 331 barrels of NGL's per day, and 2,717 Mcf of natural gas per day. Second quarter volumes represented an increase of 78% compared to the second quarter of 2013. In the second quarter of 2014, 85% of the Company's Eagle Ford production was from liquid hydrocarbons.
- Lonestar sold its Barnett assets effective May 1st, 2013 for $10.0 million. Production associated with the Barnett Shale contributed 208 BOEPD to the comparative results a year ago. Future reports will not include detail for this business segment.
- Lonestar's net production from its Conventional assets averaged 605 BOE per day during the second quarter of 2014, and was comprised of 445 barrels of oil per day, 2 barrels of NGL's per day and 951 Mcf of natural gas per day. 74% of the Company's Conventional production was from liquid hydrocarbons. 2Q14 production was 23% lower than levels reported in the second quarter of 2013, due to the sale of 28 BOEPD associated with its assets in Oklahoma and Louisiana and natural declines. Lonestar also sold one of its non-core conventional assets (Raccoon Bend) effective June 1st, 2014 which produced 76 BOE per day in recent months and 73 BOE per day in 2Q13.

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 June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($/bbl)	**$99.23**	$100.32	-1%	$97.57	$102.42	-5%
Natural Gas Liquids	($/bbl)	**$28.78**	$22.67	27%	$32.78	$26.55	23%
Natural Gas	($/Mcf)	**$4.20**	$3.78	11%	$4.52	$3.50	29%
Western Eagle Ford Shale	**($/BOE)**	**$75.41**	**$76.48**	**-1%**	**$75.55**	**$78.86**	**-4%**
Central Eagle Ford Shale							
Crude Oil	($/bbl)	**$99.79**	-	-	$98.02	-	-
Natural Gas Liquids	($/bbl)	**-**	-	-	-	-	-
Natural Gas	($/Mcf)	**-**	-	-	-	-	-
Central Eagle Ford Shale	**($/BOE)**	**$99.79**	**-**	**-**	**$98.01**	**-**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($/bbl)	**$96.29**	-	-	$95.33	-	-
Natural Gas Liquids	($/bbl)	**$30.93**	-	-	$33.13	-	-
Natural Gas	($/Mcf)	**$2.31**	-	-	$2.93	-	-
Eastern Eagle Ford Shale	**($/BOE)**	**$86.17**	**-**	**-**	**$87.47**	**-**	**-**
Total Eagle Ford Shale							
Crude Oil	($/bbl)	**$99.12**	$100.32	-1%	$97.47	$102.42	-5%
Natural Gas Liquids	($/bbl)	**$28.86**	$22.67	27%	$32.79	$26.55	23%
Natural Gas	($/Mcf)	**$4.13**	$3.78	9%	$4.48	$3.50	28%
Total Eagle Ford Shale	**($/BOE)**	**$80.19**	**$76.48**	**5%**	**$79.40**	**$78.86**	**1%**
Barnett Shale							
Crude Oil	($/bbl)	**-**	-	-	-	-	-
Natural Gas Liquids	($/bbl)	**-**	-	-	-	-	-
Natural Gas	($/Mcf)	**-**	$3.93	-100%	-	$3.37	-100%
Barnett Shale	**($/BOE)**	**-**	**$23.55**	**-100%**	**-**	**$20.24**	**-100%**
Conventional							
Crude Oil	($/bbl)	**$99.13**	$89.48	11%	$92.70	$89.70	3%
Natural Gas Liquids	($/bbl)	**$95.76**	$45.32	111%	$67.14	$45.32	48%
Natural Gas	($/Mcf)	**$6.91**	$7.28	-5%	$6.97	$6.12	14%
Conventional	**($/BOE)**	**$84.01**	**$76.81**	**9%**	**$79.58**	**$75.01**	**6%**
Total Company Wellhead							
Crude Oil	($/bbl)	**$99.12**	$96.78	2%	$96.64	$97.71	-1%
Natural Gas Liquids	($/bbl)	**$29.26**	$23.44	25%	$33.06	$26.98	23%
Natural Gas	($/Mcf)	**$4.85**	$4.91	-1%	$5.14	$4.11	25%
Total Company Wellhead	**($/BOE)**	**$80.83**	**$72.49**	**12%**	**$79.43**	**$68.58**	**16%**

Lonestar's average wellhead commodity price for the second quarter of 2014 was $80.83 per barrel of oil equivalent (BOE), which was 12% higher than the $72.49 per BOE average price realized in the second quarter of 2013. Wellhead realizations improved largely due to greater intensity of production in the Eagle Ford Shale, and the sale of its Barnett Shale assets, which comprised 8% of volumes in 2Q13, and were a drag on average realizations. Improvements in average wellhead realizations were achieved in spite of a $3.26 reduction in Louisiana Light Sweet prices compared to one year ago.

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $80.19 per BOE during 2Q14, a 5% increase compared to 2Q13. While WTI prices rose $8.77 per bbl, Louisiana Light Sweet (LLS) differentials in South Texas fell $12.03 per bbl compared to 2Q13. NGL realizations increased 27% vs. 2Q13, owing to higher WTI prices. Natural gas realizations rose 9%, in conjunction with higher Henry Hub gas prices.
- Lonestar sold its Barnett assets effective May 1st, 2013 for $10.0 million. These assets contributed 208 BOEPD of Lonestar's results in the second quarter of 2013. Sale of this asset, which garnered relatively low BOE wellhead realizations, has served to improve the Company's reported average wellhead price realization.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $84.01 per BOE during 2Q14, up 9% versus 2Q13. Higher crude oil pricing were largely responsible for the improvement in wellhead realizations, partially offset by lower natural gas realizations.

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 June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($,000)	**$13,956**	$10,713	30%	**$29,164**	$18,522	57%
Natural Gas Liquids	($,000)	**$835**	$533	57%	**$2,043**	$938	118%
Natural Gas	($,000)	**$1,002**	$540	85%	**$2,194**	$875	151%
Western Eagle Ford Shale Revenues	**($,000)**	**$15,793**	**$11,787**	**34%**	**$33,401**	**$20,335**	**64%**
Central Eagle Ford Shale							
Crude Oil	($,000)	**$4,517**	$0	-	**$7,374**	$0	-
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$0	-	**$0**	$0	-
Central Eagle Ford Shale Revenues	**($,000)**	**$4,517**	**$0**	**-**	**$7,374**	**$0**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($,000)	**$1,583**	$0	-	**$3,161**	$0	-
Natural Gas Liquids	($,000)	**$35**	$0	-	**$63**	$0	-
Natural Gas	($,000)	**$20**	$0	-	**$39**	$0	-
Eastern Eagle Ford Shale Revenues	**($,000)**	**$1,638**	**$0**	**-**	**$3,264**	**$0**	**-**
Total Eagle Ford Shale							
Crude Oil	($,000)	**$20,057**	$10,713	87%	**$39,699**	$18,522	114%
Natural Gas Liquids	($,000)	**$870**	$533	63%	**$2,107**	$938	125%
Natural Gas	($,000)	**$1,022**	$540	89%	**$2,233**	$875	155%
Total Eagle Ford Shale Revenues	**($,000)**	**$21,949**	**$11,787**	**86%**	**$44,039**	**$20,335**	**117%**
Barnett Shale							
Crude Oil	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$446	-100%	**$0**	$1,507	-100%
Barnett Shale Revenues	**($,000)**	**$0**	**$446**	**-100%**	**$0**	**$1,507**	**-100%**
Conventional							
Crude Oil	($,000)	**$4,011**	$4,645	-14%	**$7,960**	$9,528	-16%
Natural Gas Liquids	($,000)	**$17**	$37	-54%	**$35**	$37	-7%
Natural Gas	($,000)	**$598**	$833	-28%	**$1,242**	$1,473	-16%
Conventional Revenues	**($,000)**	**$4,625**	**$5,516**	**-16%**	**$9,237**	**$11,037**	**-16%**
Total Company Wellhead							
Crude Oil	($,000)	**$24,067**	$15,358	57%	**$47,659**	$28,050	70%
Natural Gas Liquids	($,000)	**$887**	$571	55%	**$2,141**	$975	120%
Natural Gas	($,000)	**$1,620**	$1,819	-11%	**$3,476**	$3,854	-10%
Total Company Wellhead Revenues	**($,000)**	**$26,574**	**$17,748**	**50%**	**$53,276**	**$32,879**	**62%**

Lonestar's net wellhead oil and gas revenues for the second quarter of 2014 rose 50% to $26.6 million, versus $17.8 million a year ago. Revenue growth was a function of a 34% increase in production coupled with 12% increase in realized wellhead prices.

- Lonestar's net oil and gas revenues from its Eagle Ford Shale assets rose 86% to $22.0 million for the second quarter of 2014 versus $11.8 million a year ago. Revenue growth was driven by a 78% increase in production coupled with a 5% increase in wellhead price realizations per BOE. Crude oil contributed 91% of revenues, while natural gas liquids contributed 4% of revenues and natural gas contributed 5% of revenues.
- Lonestar sold its Barnett assets effective May 1st, 2013 for $10.0 million. These assets contributed 208 BOEPD and $0.4 million to Lonestar's wellhead oil and gas revenues in the second quarter of 2013.
- Lonestar net oil and gas revenues from its Conventional assets totaled $4.6 million during the second quarter of 2014, a 16% decrease over the second quarter of 2013. Crude oil contributed 87% of revenues while natural gas liquids contributed 0% of revenues and natural gas contributed 13% 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 97 BOEPD in 2Q13.

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

Management's Discussion and Analysis

Field Operating Expenses

		Three months ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Western Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$10.41**	$7.12	46%	**$9.12**	$7.06	29%
Production Taxes	($/BOE)	**$4.68**	$4.39	7%	**$4.54**	$4.63	-2%
Western Eagle Ford Shale	**($/BOE)**	**$15.08**	**$11.51**	**31%**	**$13.66**	**$11.69**	**17%**
Central Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$12.10**	$0.00	-	**$11.18**	$0.00	-
Production Taxes	($/BOE)	**$6.45**	$0.00	-	**$5.88**	$0.00	-
Central Eagle Ford Shale	**($/BOE)**	**$18.55**	**$0.00**	**-**	**$17.05**	**$0.00**	**-**
Eastern Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$6.40**	$0.00	-	**$0.00**	$0.00	-
Production Taxes	($/BOE)	**$7.89**	$0.00	-	**$0.00**	$0.00	-
Eastern Eagle Ford Shale	**($/BOE)**	**$14.29**	**$0.00**	**-**	**$0.00**	**$0.00**	**-**
Total Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$10.41**	$7.12	46%	**$8.78**	$7.06	24%
Production Taxes	($/BOE)	**$5.19**	$4.39	18%	**$4.42**	$4.63	-5%
Total Eagle Ford Shale	**($/BOE)**	**$15.60**	**$11.51**	**36%**	**$13.20**	**$11.69**	**13%**
Barnett Shale							
Lease Operating Expense	($/BOE)	**$0.00**	$10.54	-100%	**$0.00**	$11.21	-100%
Production Taxes	($/BOE)	**$0.00**	$1.24	-100%	**$0.00**	$1.24	-100%
Barnett Shale	**($/BOE)**	**$0.00**	**$11.79**	**-100%**	**$0.00**	**$12.45**	**-100%**
Conventional							
Lease Operating Expense	($/BOE)	**$22.16**	$24.38	-9%	**$19.44**	$23.31	-17%
Production Taxes	($/BOE)	**$7.91**	$7.78	2%	**$5.71**	$7.24	-21%
Conventional	**($/BOE)**	**$30.07**	**$32.15**	**-6%**	**$25.15**	**$30.56**	**-18%**
Total Company							
Lease Operating Expense	($/BOE)	**$12.38**	$12.45	-1%	**$10.63**	$12.69	-16%
Production Taxes	($/BOE)	**$5.65**	$5.14	10%	**$4.64**	$4.91	-5%
Total Company	**($/BOE)**	**$18.02**	**$17.59**	**2%**	**$15.27**	**$17.60**	**-13%**

Lonestar's field operating expenses for the second quarter of 2014 were $5.9 million, an increase of 38% over second quarter 2013 field operating expenses of $4.3 million. On a unit of production basis, the Company's field operating expenses rose 2% from 2Q13 to $18.02 per BOE. Lease Operating Expense ("LOE") was $4.1 million for the second quarter of 2014, a 34% increase over comparable levels in 2013. Higher lease operating expenses were primarily a function of a 34% increase in oil and gas production. Production taxes were $1.9 million for the second quarter of 2014, a 48% 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 $4.3 million during the second quarter of 2014, a 141% increase over the second quarter of 2013. On a unit of production basis, field operating expenses increased 36% to $15.60 per BOE. The Company incurred higher costs while recovering from the frac-related well outages, which also reduced production in the quarter, impacting both the numerator and denominated of the LOE per BOE figure. Lonestar expects improvement in LOE both in absolute dollars and on a per-unit basis, as these costs are not expected to recur. Lonestar Lease operating expense was $2.8 million, or $10.41 per BOE, compared to $1.1 million, or $7.12 per BOE in the prior quarter. Production taxes were $1.4 million, or $5.19 per BOE, compared to $0.7 million, or $4.39 per BOE in the year-ago quarter.
- Lonestar sold its Barnett assets effective May 1st, 2013 for $10.0 million.
- Lonestar's field operating expenses from its Conventional assets totaled $1.7 million during the second quarter of 2014, a 28% decrease versus the second quarter of 2013. On a unit of production basis, field operating expenses decreased 6% to $30.07 per BOE. Lease operating expense was $1.2 million, or $22.16 per BOE, compared to $1.8 million, or $24.38 per BOE in 2Q13. Production taxes were $0.4 million, or $7.91 per BOE, compared to $0.6 million, or $7.78 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 June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Western Eagle Ford Shale							
Production Revenue	($/BOE)	$75.41	$76.48	-1%	$75.55	$78.86	-4%
Lease Operating Expenses	($/BOE)	$10.41	$7.12	46%	$9.12	$7.06	29%
Production Taxes	($/BOE)	$4.68	$4.39	7%	$4.54	$4.63	-2%
Field Netback	**($/BOE)**	**$60.33**	**$64.97**	**-7%**	**$61.89**	**$67.17**	**-8%**
Field Netback	**($MM)**	**$12.6**	**$10.0**	**26%**	**$27.4**	**$17.32**	**58%**
Central Eagle Ford Shale							
Production Revenue	($/BOE)	$99.79	-	-	$98.01	-	-
Lease Operating Expenses	($/BOE)	$12.10	-	-	$11.18	-	-
Production Taxes	($/BOE)	$6.45	-	-	$5.88	-	-
Field Netback	**($/BOE)**	**$81.24**	**-**	**-**	**$80.95**	**-**	**-**
Field Netback	**($MM)**	**$3.7**	**-**	**-**	**$6.1**	**-**	**-**
Eastern Eagle Ford Shale							
Production Revenue	($/BOE)	$86.17	-	-	$87.47	-	-
Lease Operating Expenses	($/BOE)	$6.40	-	-	-	-	-
Production Taxes	($/BOE)	$7.89	-	-	-	-	-
Field Netback	**($/BOE)**	**$71.89**	**-**	**-**	**$87.47**	**-**	**-**
Field Netback	**($MM)**	**$1.4**	**-**	**-**	**$3.3**	**-**	**-**
Total Eagle Ford Shale							
Production Revenue	($/BOE)	$80.19	$76.48	5%	$79.40	$78.86	1%
Lease Operating Expenses	($/BOE)	$10.41	$7.12	46%	$8.78	$7.06	24%
Production Taxes	($/BOE)	$5.19	$4.39	18%	$4.42	$4.63	-5%
Field Netback	**($/BOE)**	**$64.59**	**$64.97**	**-1%**	**$66.20**	**$67.17**	**-1%**
Field Netback	**($MM)**	**$17.7**	**$10.0**	**77%**	**$36.7**	**$17.32**	**112%**
Barnett Shale							
Production Revenue	($/BOE)	-	$23.55	-100%	-	$20.24	-100%
Lease Operating Expenses	($/BOE)	-	$10.54	-100%	-	$11.21	-100%
Production Taxes	($/BOE)	-	$1.24	-100%	-	$1.24	-100%
Field Netback	**($/BOE)**	**-**	**$11.77**	**-100%**	**-**	**$7.79**	**-100%**
Field Netback	**($MM)**	**-**	**$0.2**	**-100%**	**-**	**$0.58**	**-100%**
Conventional							
Production Revenue	($/BOE)	$84.01	$76.81	9%	$79.58	$75.01	6%
Lease Operating Expenses	($/BOE)	$22.16	$24.38	-9%	$19.44	$23.31	-17%
Production Taxes	($/BOE)	$7.91	$7.78	2%	$5.71	$7.24	-21%
Field Netback	**($/BOE)**	**$53.93**	**$44.65**	**21%**	**$54.43**	**$44.46**	**22%**
Field Netback	**($MM)**	**$3.0**	**$3.2**	**-7%**	**$6.3**	**$6.5**	**-3%**
Total Company							
Production Revenue	($/BOE)	$80.83	$72.49	12%	$79.43	$68.58	16%
Lease Operating Expenses	($/BOE)	$12.38	$12.45	-1%	$10.63	$12.69	-16%
Production Taxes	($/BOE)	$5.65	$5.14	10%	$4.64	$4.91	-5%
Field Netback	**($/BOE)**	**$62.80**	**$54.90**	**14%**	**$64.16**	**$50.98**	**26%**
Field Netback	**($MM)**	**$20.6**	**$13.4**	**54%**	**$43.0**	**$24.4**	**76%**

Lonestar's field netback for the second quarter of 2014 was $20.6 million, an increase of 54% over the field netback of $13.4 million in 2Q13. On a per BOE basis, field netbacks improved 14% to $62.80 in the second quarter of 2014 vs. $54.90 in the second quarter of 2013. The increase in the per BOE field netback is associated with substantial improvements in the netbacks associated with the Conventional assets and the sale of the Company's low-margin Barnett Shale gas properties.

- Lonestar's field netback from its Eagle Ford Shale assets totaled $17.7 million during the second quarter of 2014, which represents a 77% increase in field netbacks compared to the $10.0 million reported in the second quarter of 2013. On a BOE basis, field netbacks remained virtually flat compared to the second quarter of 2013
- Lonestar sold its Barnett assets effective May 1st, 2013 for $10.0 million, while the Barnett Shale assets contributed $0.2 million to Field Netbacks in 2Q13. The sale of these assets, which had substantially lower field netbacks than the Company's other assets, served to contribute to higher field netbacks at the corporate level.
- Lonestar's field netback from its Conventional assets totaled $3.0 million during the second quarter of 2014 which represents a 7% decrease in field netbacks compared to the $3.2 million reported in the second quarter of 2013. On a BOE basis, field netbacks increased 21% due largely to a 28% reduction in lease operating expenses and production taxes.

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

Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Total Expense	($,000)	$9,673	$5,981	62%	$17,538	$11,453	53%
Depreciation & Depletion	($/BOE)	$29.42	$24.43	20%	$51.29	$48.82	5%

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 second quarter of 2014 was $9.7 million, or $29.42 per BOE compared to $6.0 million, or $24.43 per BOE reported in the second quarter of 2013. Lonestar estimates that the Depreciation and Depletion expense for 3Q14 will be $24.13 per BOE, back inline with historical levels

General and Administrative Expenses

		Three months ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Total Expense	($,000)	$2,078	$2,021	3%	$3,863	$4,198	-8%
General & Administrative	($/BOE)	$6.32	$8.25	-23%	$11.30	$17.90	-37%

Lonestar reported General & Administrative expenses of $2.1 million for the second quarter of 2014, a 3% increase over the $2.0 million of General & Administrative expenses reported in the second quarter of 2013. G&A rose 16% on a sequential basis, as the Company increased its payroll, hiring a Chief Operating Officer, 2 new senior engineers, and selected other staff members. Based on its current business outlook, the Company does not anticipate similar increases in staff levels and payroll in future periods. On a BOE basis, the Company reported a 28% reduction in G&A per BOE of $6.32, compared to $8.82 reported in the second quarter of 2013. The reduction on G&A expenses on a BOE basis from 2Q14 to 2Q13 is largely a function of increasing production volumes, and the Company expects continued reductions in G&A on a unit basis as Lonestar achieves further scale.

Finance Expenses

		Three months ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Interest Expense	($,000)	$5,998	$753	696%	$7,310	$1,173	523%
Amortization of Finance Costs	($,000)	$1,342	$66	1928%	$1,583	$138	1051%
Total Finance Costs	**($,000)**	**$7,341**	**$820**	**796%**	**$8,893**	**$1,311**	**578%**
Finance Costs	($/BOE)	$22.33	$3.35	**567%**	$26.01	$5.59	**365%**

Lonestar reported Finance expenses of $7.3 million for the second quarter of 2014, a 796% increase over the $0.8 million of Finance expenses reported in the second quarter of 2013. Increased Finance expenses are a result of the placement of the Company's 8 .75% Notes and the financing costs associated with the amendment of the Company's credit agreements required to close its acquisition and the Notes offering. The Company also incurred a prepayment charge of $1.1 million associated with the early extinguishment of its 2nd lien credit facility. The Company's borrowings from its two credit facilities averaged $220.0 million during the quarter and interest expense averaged 8.75% on an annualized rate during the quarter, and its $108.5 million Revolver remained undrawn at the end of 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 June 30,			Six Months Ended June 30,		
		2014	**2013**	**% Change**	**2014**	**2013**	**% Change**
Crude Oil	($,000)	**($1,869)**	$91	-2157%	**($2,921)**	$68	-4377%
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	($40)	-100%	**$0**	($20)	-100%
Hedging Revenues (Expenses)	**($,000)**	**($1,869)**	**$51**	**-3756%**	**($1,052)**	**($3)**	**40321%**
Hedging Revenues (Expenses)	($/BOE)	**($5.68)**	$0.21		**($276.91)**	$0.65	

- Lonestar realized crude oil hedge expense of $1.9 million in the second quarter of 2014 vs. a crude oil hedge income of $0.09 million reported in the second quarter of 2013.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	147,200	July 1, 2014	-	Dec 31, 2014	WTI	$93.90	-	-	Swap
Crude Oil	53,900	July 1, 2014	-	Dec 31, 2014	WTI	$90.70	-	-	Swap
Crude Oil	16,400	July 1, 2014	-	Dec 31, 2014	WTI	$94.00	-	-	Swap
Crude Oil	65,800	July 1, 2014	-	Sep 30, 2014	WTI	$104.65	-	-	Swap
Crude Oil	43,100	Nov 1, 2014	-	Dec 31, 2014	WTI	$101.38	-	-	Swap
Crude Oil	56,000	July 1, 2014	-	Dec 31, 2014	LLS	$97.00	-	-	Swap
Crude Oil	46,000	Jul 1, 2014	-	Sep 30, 2014	LLS	$95.40	-	-	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	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 first quarter of 2014, the Company entered into additional WTI Crude Oil hedge contracts totaling; 108,900 barrels for the remainder of 2014 placed monthly for an average strike price of $103.02 per barrel, 213,900 barrels in 2015 placed monthly for an average strike price of $94.91 per barrel, and 309,000 barrels in 2016 placed monthly for a strike price of $90.45 per barrel.

Non-recurring Expense

Lonestar recorded $0.6 million of regulatory mandated P&A expenses during the second quarter of 2014 on the Conventional Assets. 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 June 30, 2014

Consolidated statement of comprehensive income

For the three and six months ended June 30, 2014 and 2013

(US $,000)	*As Reported* Three months ended June 30, 2014	2013	*As Reported* Six Months Ended June 30, 2014	2013
Revenues (Net of Royalties)				
Crude Oil	24,067	15,358	47,659	28,050
Natural Gas Liquids	887	571	2,141	975
Natural Gas	1,620	1,819	3,476	3,854
Revenues (Net of Royalties)	**26,574**	**17,748**	**53,276**	**32,879**
Hedge Revenues (Expenses)	(1,869)	51	(2,921)	49
Net Revenue From Ordinary Activities	**24,705**	**17,799**	**50,355**	**32,927**
Operating Expenses				
Lease Operating Expenses	(4,069)	(3,048)	(7,365)	(6,085)
Severance Taxes	(1,290)	(899)	(2,481)	(1,302)
Ad Valorem Taxes	(567)	(359)	(858)	(1,051)
Depreciation, Depletion & Amortization	(9,673)	(5,981)	(17,538)	(11,453)
General & Administrative	(2,078)	(2,021)	(3,863)	(4,198)
Total Operating Expenses	**(17,677)**	**(12,308)**	**(32,105)**	**(24,088)**
Gross Profit from Operating Activities	**7,028**	**5,491**	**18,249**	**8,839**
Other Income (Expense)	**463**	**12,775**	**463**	**12,783**
Stock based compensation	**(886)**	**0**	**(1,334)**	**(170)**
Non-recurring expenses	**(612)**	**0**	**(1,050)**	**0**
Interest & Other Finance Expenses	**(7,341)**	**(820)**	**(8,893)**	**(1,311)**
Fair Value Gain (Loss) on derivatives	**(6,140)**	**2,162**	**(8,325)**	**2,454**
Profit (Loss) before taxes	**(7,487)**	**19,608**	**(891)**	**22,595**
Income tax (expense) benefit	**511**	**(5,021)**	**(1,042)**	**(6,082)**
Net Income (Loss)	**(6,977)**	**14,588**	**(1,933)**	**16,513**
EBITDAX	**16,701**	**11,473**	**35,787**	**20,291**

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

Consolidated statement of financial position
As of June 30, 2014

(US $,000)	June 30, 2014	*As Reported* As of March 31, 2014	December 31, 2013
Assets			
Current Assets			
Cash and cash equivalents	13,498	5,801	6,744
Trade and other receivables	18,196	12,108	7,823
Derivative financial instruments	33	7	157
Other assets	932	686	507
Total current assets	**32,659**	**18,602**	**15,231**
Non-current assets			
Oil and Gas Properties & Equipment	410,117	388,990	293,478
Deferred tax assets	81	79	43,175
Derivative financial instruments	10	110	490
Other non-current assets	4,307	2,458	2,157
Total non-current assets	**414,515**	**391,637**	**339,299**
Total Assets	**447,174**	**410,239**	**354,530**
Liabilities			
Current liabilities			
Trade and other payables	14,961	17,397	9,197
Revenue payable	3,150	2,790	4,087
Accrued expenses	16,906	2,270	2,067
Derivative financial instruments	7,277	3,692	-
Total current liabilities	**42,294**	**26,149**	**15,351**
Non-current liabilities			
Long-term Debt	215,051	190,000	109,000
Deferred tax liablilities	10,136	10,658	53,280
Other non-current liabilities	10,881	8,538	9,195
Total non-current liabilities	**236,068**	**209,195**	**171,475**
Total Liabilities	**278,362**	**235,345**	**186,826**
Net assets	**168,812**	**174,894**	**167,704**
Equity			
Contributed equity	142,638	142,638	142,638
Share-based payment reserve	8,770	7,876	4,450
Retained Earnings	17,404	24,380	20,616
Total Equity	**168,812**	**174,894**	**167,704**

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

Consolidated statement of cash flows
As of June 30, 2014

(US $,000)	*As Reported* Three Months Ending March 31, 2014	Three Months Ending June 30, 2014	Six Months Ending June 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Profit/(loss) for the year	5,046	(6,977)	(1,931)
Adjustments to reconcile profit/(loss) to net cash	-		-
provided by operating activities:	-		-
Gain on sale of oil and gas properties	-	(466)	(466)
Depreciation, depletion, amortisation	7,814	9,627	17,441
Increase in retirement provision	51	46	97
Deferred taxes	2,220	(1,013)	1,207
Share based payments	448	886	1,334
Non-cash interest expense	-	275	275
Changes in operating assets and liabilities:	-		-
Accounts receivable	(4,190)	(6,088)	(10,277)
Other assets	(611)	(2,095)	(2,706)
Accounts payable and provisions	7,109	11,197	18,305
Net cash inflow from operating activities	17,887	5,392	23,279
CASH FLOWS FROM INVESTING ACTIVITIES			
Payments for oil and gas property, plant & equipment	(30,899)	(32,293)	(63,192)
Acquisition of oil and gas properties	(70,978)	-	(70,978)
Net (increase) decrease in derivatives	2,047	6,928	8,975
Proceeds from sales of oil and gas properties	-	3,200	3,200
Net cash (outflow) from investing activities	(99,830)	(22,165)	(121,995)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net change in borrowings	81,000	(190,030)	(109,030)
Proceeds from issuance of long term bonds	-	214,500	214,500
Net cash inflow from financing activities	81,000	24,470	105,470
Net increase in cash held	(943)	7,697	6,754
Cash and cash equivalents at the beginning of the financial period	6,744	5,801	6,744
Cash and cash equivalents at the end of the financial period	5,801	13,498	13,498

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	$92.48	$4.25

- 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 <u>Eagle Ford Shale properties</u> 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 <u>Conventional properties</u> 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."