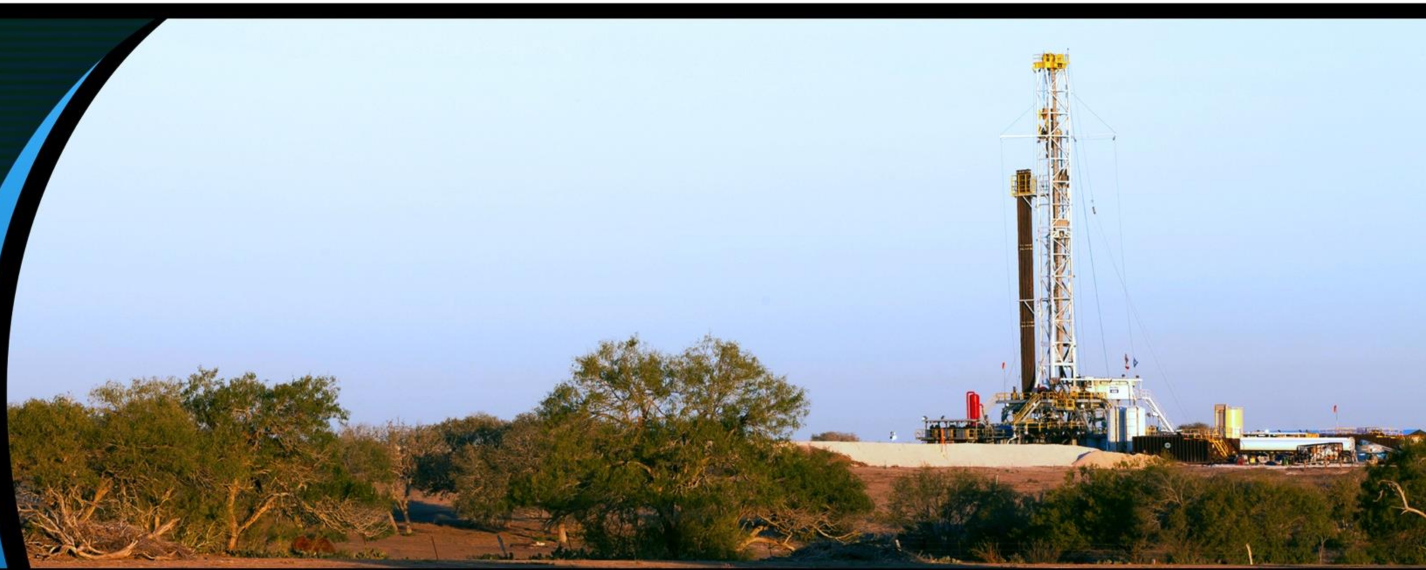

aurora OIL&GASLIMITED

3rd Quarter 2013 Operating and Financial Results

November 2013

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Management also uses certain industry benchmarks such as net operating income and operating netback to analyse financial and operating performance. "Net Operating Income" represents net oil and gas revenue attributable to Aurora after distribution to royalty holders. "Operating netback", as presented, represents revenue from production less royalties, state taxes, transportation and operating expenses calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

Forward-looking Information

Statements in this presentation which reflect management's expectations relating to, among other things, production estimates, changes in reserves, target dates, Aurora's expected drilling program and the ability to fund development are forward-looking statements, and can generally be identified by words such as "will", "expects", "intends", "believes", "estimates", "anticipates" or similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements and may contain forward-looking information and financial outlook information, as defined by Canadian securities laws. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that some or all of the reserves described can be profitably produced in the future. These statements are not historical facts but instead represent management's expectations, estimates and projections regarding future events.

Although management believes the expectations reflected in such forward-looking statements and financial outlook information are reasonable, forward-looking statements and financial outlook 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 and financial outlook information. These factors include risks related to: exploration, development and production; oil and gas prices, markets and marketing; acquisitions and dispositions; our ability to comply with covenants under our debt facilities; competition; additional funding requirements; our ability to raise capital and access debt and equity capital markets; reserve estimates being inherently uncertain; changes in the rate and /or location of future drilling programs on our acreage by our operator(s); incorrect assessments of the value of acquisitions and exploration and development programs; environmental concerns; availability of, and access to, drilling equipment; reliance on key personnel; title to assets; expiration of licences and leases; credit risk; hedging activities; litigation; government policy and legislative changes; unforeseen expenses; negative operating cash flow; contractual risk; and management of growth. In addition, 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 and financial outlook information contained in this document. Such assumptions include, but are not limited to, general economic, market and business conditions and corporate strategy. Accordingly, readers are cautioned not to place undue reliance on such statements. Further, the financial outlook information regarding future production and future production revenue is included to assist readers in assessing the potential impact of current drilling plans on our performance and may not be appropriate to be relied on for any other purposes.

All of the forward-looking information and financial outlook in this presentation is expressly qualified by these cautionary statements. Forward-looking information and financial outlook contained herein is made as of the date of this document and Aurora disclaims any obligation to update any forward-looking information or financial outlook, whether as a result of new information, future events or results or otherwise, except as required by law. In relation to details of the forward looking drilling program, management advises that this is subject to change as conditions warrant, and we can provide no assurances that this number of rigs will be available or will be utilised or that any targeted well count will be achieved.

Disclosure of Reserves

The reserves shown in this presentation are estimates only and should not be construed as exact quantities. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable; probable reserves are those additional reserves which are less certain to be recovered than proved reserves. Possible reserves are those additional reserves which are less certain to be recovered than probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this presentation. Estimates of reserves may increase or decrease as a result of future operations, market conditions, or changes in regulations.

Unless otherwise indicated, all estimates of Aurora's midyear reserves in this presentation have been prepared by Aurora in accordance with the COGE Handbook effective as of June 30, 2013 ("Midyear Report"). Price assumptions used in the Midyear Report are as follows (FY13/14/15/16/17+): Oil US$98.26/bbl, US$92.40/bbl, US$86.91/bbl, US$83.59/bbl, and US$83.59/bbl; and Natural gas US$3.72/mscf, US$3.97/mscf, US$4.17/mscf, US$4.32/mscf, and US$4.32/mscf. For disclosure of methodology, see Aurora's September 8, 2013 press release.

References to Aurora's reserves as at December 31, 2012 in this presentation are to the reserve estimates prepared or evaluated in accordance with the COGE Handbook effective as of 31 December 2012 and derived from a January 30, 2013 reserves report prepared by Ryder Scott Company, L.P. ("RS") ("RS Report"). RS are qualified independent reserves evaluators under the Canadian Securities Administrators National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. Price assumptions used in the RS Report are as follows (FY13/14/15/16/17+): Oil US$101.00/bbl, US$100.00/bbl, US$98.00/bbl, US$96.00/bbl, and US$95.00/bbl; and Natural gas US$3.60/mscf, US$4.00/mscf, US$4.20/mscf, US$4.40/mscf, and US$4.60/mscf.

Defined Terms

Defined Reserves and Resource Terms

- “bbl” means barrel.
- “boe” means barrels of oil equivalent, and have been calculated using liquid volumes of oil, condensate and NGLs and treated volumes of gas converted using a ratio of 6 mscf to 1 bbl liquid equivalent, unless otherwise stated.
- “scf” means standard cubic feet.
- “M” or “m” prefix means thousand.
- “MM” or “mm” prefix means million.
- “B” or “b” prefix means billion.
- “pd” or “/d” suffix means per day.
- ”NGL” means natural gas liquids.
- “TMD” means Total Measured Depth
- “IP” means Initial Production.

Other defined terms

- “AMI” means Area of Mutual Interest.
- “CAGR” means compounded annual growth rate.
- “CQGR” means compounded quarterly growth rate.
- “NPBT” means net profit before tax.
- “NPAT” means net profit after tax.
- “WTI” means West Texas Intermediate crude.
- “LLS” means Louisiana Light Sweet crude.
- “LTM” means last twelve months.
- “Sugarkane” or “Sugarkane Field” means the two contiguous fields designated by the Texas Railroad Commission as the Sugarkane and Eagleville Fields.
- “$” or “US$” means United States (US) dollars, unless otherwise stated.
- “WI” means working interest within leases, AMI or wells.

Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mscf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mscf:1 bbl, utilising a conversion ratio of 6 mscf:1 bbl may be misleading. Unless stated otherwise, all per boe references are a reference to Aurora’s per boe production on a working interest basis before deduction of royalties.

Q3 2013 Results at a Glance (vs. Q3 2012)

+62% EBITDAX[1] of US$81mm

Last 12 months EBITDAX US$301mm

+71% Production of 1.97 mmboe gross

+70% Production 15,785 boe/d net of royalties

(1) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

Eagle Ford Focused

- **Developing highly contiguous ~80,300 gross (22,100 net) acres in the Sugarkane field**
  - 97% held by production
- **Q3 2013 average production:**
  - ~15,785 net boe/d
  - ~21,438 gross boe/d
- **Commenced production in Q3 2013 from:**
  - 10 new net wells
  - Includes 2 net operated wells in late Sept.
- **Mid Year Reserve Estimates:**

(mmboe)	1P	2P	3P(3)
Pre-royalty	112.0	132.7	203.3
Post-royalty	82.7	98.2	150.5

- **Strong liquidity with US$106mm cash and an undrawn US$300mm credit facility**

KEY METRICS

Market Cap(1) (US$)	$1.38	billion
Cash (US$)	$106	million
Total Debt(US$)	$665	million
Enterprise Value (US$)	$1.94	billion
YTD 2013 EBITDAX(2) (US$)	$237	million
Q3 2013 EBITDAX (US$)	$81	million
Last 12 Months EBITDAX (US$)	$301	million
Q3 2013 average production (pre-royalty)	21,438	boe/d
Q3 2013 average production (post-royalty)	15,785	boe/d
Q3 2013 production (pre-royalty)	1.97	mmboe
Q3 2013 production (post-royalty)	1.45	mmboe

(1) Based on ASX closing price of A$3.24 per share on October 29, 2013 using an exchange rate A$1=US$0.9476.
(2) See “Non-IFRS Financial Measures” above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.
(3) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will be equal or exceed the sum of the proved plus probable plus possible (3P) reserves.

Q3 2013 Update

- **Average daily production of 15,785 boe/d (net) up 70% compared to the Q3 2012**
- **37 gross new producing wells during Q3 2013**
- **13 net wells spud; 10 net wells placed on production**
  - 7 net operated wells spud; 2 net operated wells placed on production
- **Added an additional operated rig**
  - Forward plan calls for 1 to 2 operated rigs, depending on non-operated program and overall capital allocations
- **At end Q3 2013, 10 gross wells under stimulation, 21 gross wells awaiting completion, 12 gross wells in drilling status**
- **Additional reserve potential of Sugarkane**
  - Continuing evaluation of data collection from Austin Chalk pilot programs
  - Anticipate Eagle Ford well-spacing release in December, 2013

Q3 2013 Update (continued)

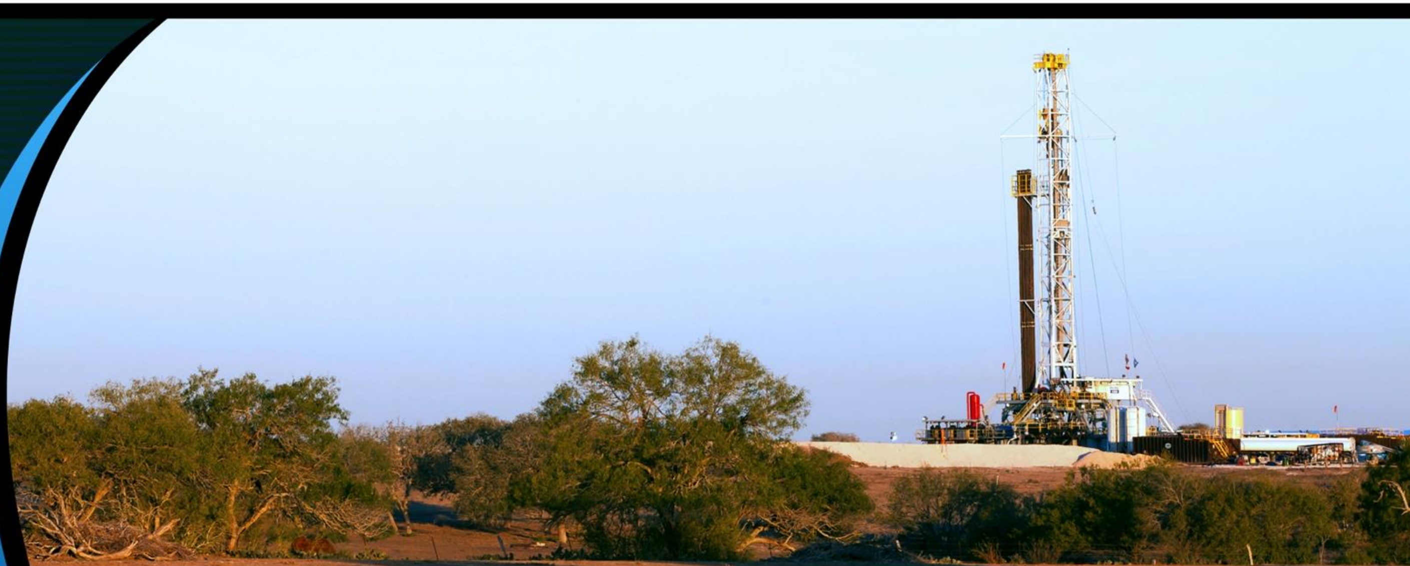
- **YTD financial performance**
  - YTD EBITDAX[(1)] of US$237mm
  - Capital expenditures of US$353mm in first 9-months of 2013 (excluding acquisitions)
  - Q3 2013 EBITDAX from non-operated Sugarkane assets exceeded capex investment
- **2013 development program weighted to second half**
  - Drilling program (net to Aurora) increases during 2H 2013
  - Production growth to continue into 2014
- **Continued to build a high-quality operating team**
- **"Safety is everyone's business" – good safety record on operated acreage**

(1) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

2013 Guidance Update

2013 Guidance	Initial Guidance	Updated Guidance
Net well spud – total	45 to 50	42 to 47[1]
Net well spud – Operated Net well spud – Non operated	14 to19 30 to 32	10 to 12[1] 32 to 35
Cumulative production Gross(mmboe) Net(mmboe)	7.2 to 8.0 5.3 to 5.9	7.4 to 7.7 5.5 to 5.7
2013 Average Daily production Gross(boe/d) Net(boe/d)	19,700 to 21,900 14,500 to 16,200	20,300 to 21,100 15,000 to 15,600
Capital expenditure - development ($millions)	$430 to $465	$490 to $510[2]

- Operated lateral wells being drilled longer = less wells to achieve the same lateral footage contact with the Eagle Ford reservoir. Guidance was based on a higher number of wells with shorter laterals. These longer lateral wells are expected to generate capital cost savings while achieving the same overall total footage contact [1]
- Development capex reflects increased drilling activity and investment in infrastructure during 2013 and includes costs for wells expected in inventory at year end. These wells will be brought on production in Q1 2014 [2]



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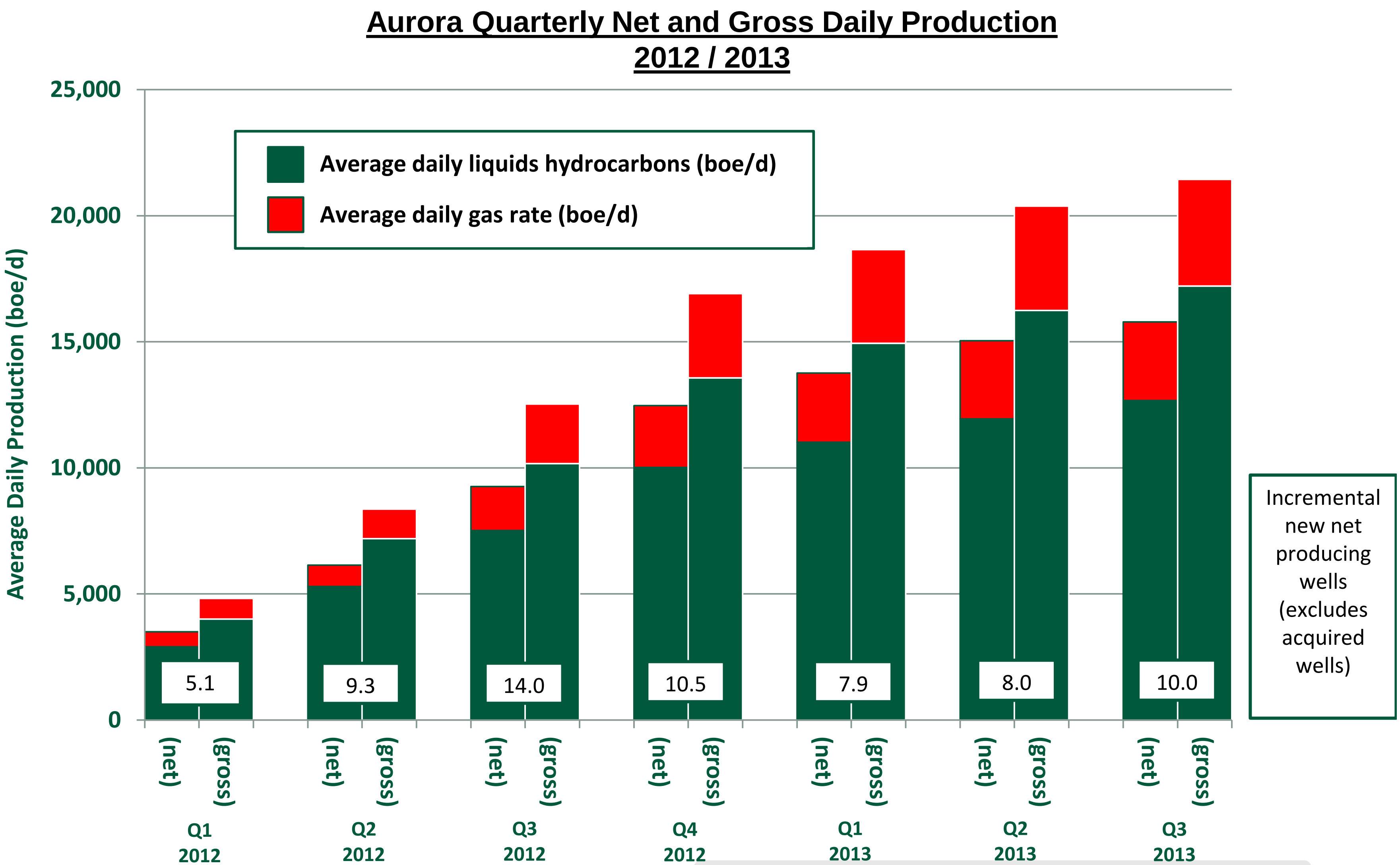
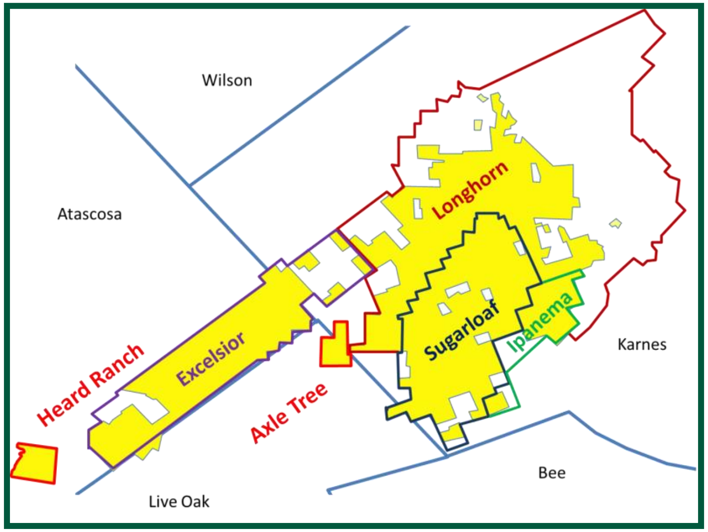
Operational Overview

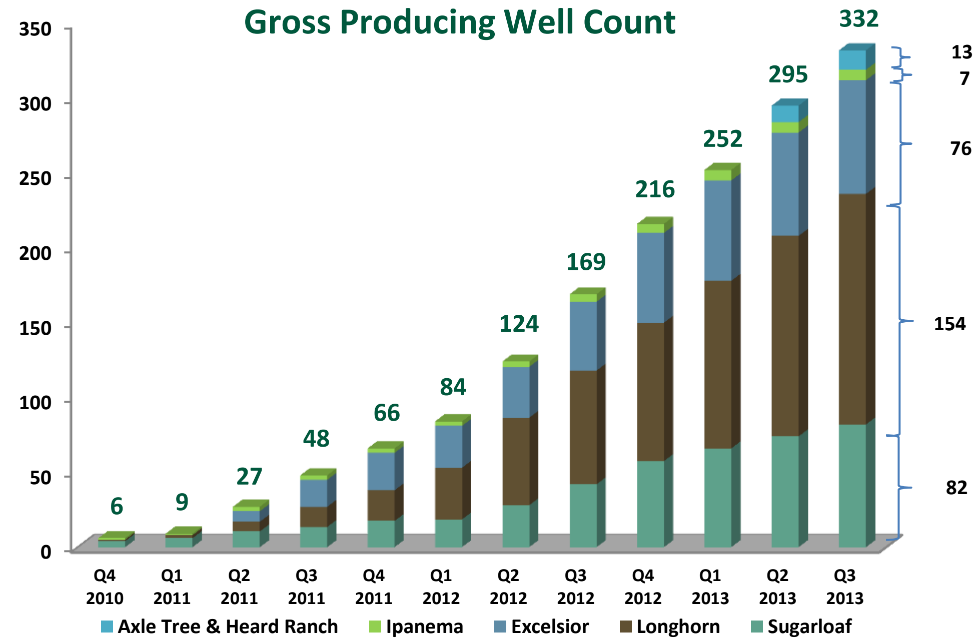
Quarterly Production Growth



Well Status Summary



Sugarkane Field Project Areas



Gross Well Status Sept 30, 2013	Sugarloaf (28.1%)(2)	Longhorn (31.9%)(2)	Ipanema (36.4%)(2)	Excelsior (9.1%)(2)	Non-Operated Sub – total	Axle Tree & Heard Ranch (100%)(1)	Total
Producing	82	154	7	76	319	13	332
Stimulation Underway	1	4	-	3	8	2	10
Completions	11	6	-	4	21	-	21
Drilling	-	4	-	3	7	5	12
Total	94	168	7	86	355	20	375

(1) Operated acreage acquired effective date March 1, 2013.
(2) AMI interests are not always indicative of actual working interests in each well in such AMI.

Operational Highlights

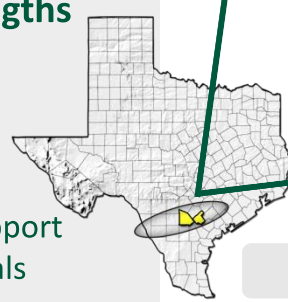
- **New drilling techniques enhance already strong economics**
  - Longer laterals
  - Pad drilling
  - Down-spaced operated Eagle Ford to 40 acres (approximately 330 foot lateral distance between wells)
  - Anticipate Eagle Ford well-spacing release in December 2013

- **New completion techniques adopted for "standard" development**
  - Zipper Frac
  - HiWAY Frac
  - Proppant concentration/type
  - Fluid concentration/type
  - Choke management
  - Optimized artificial lift

- **Currently averaging non-operated drill & complete AFE's of US$7.8mm with an average lateral length of 5,400 ft**

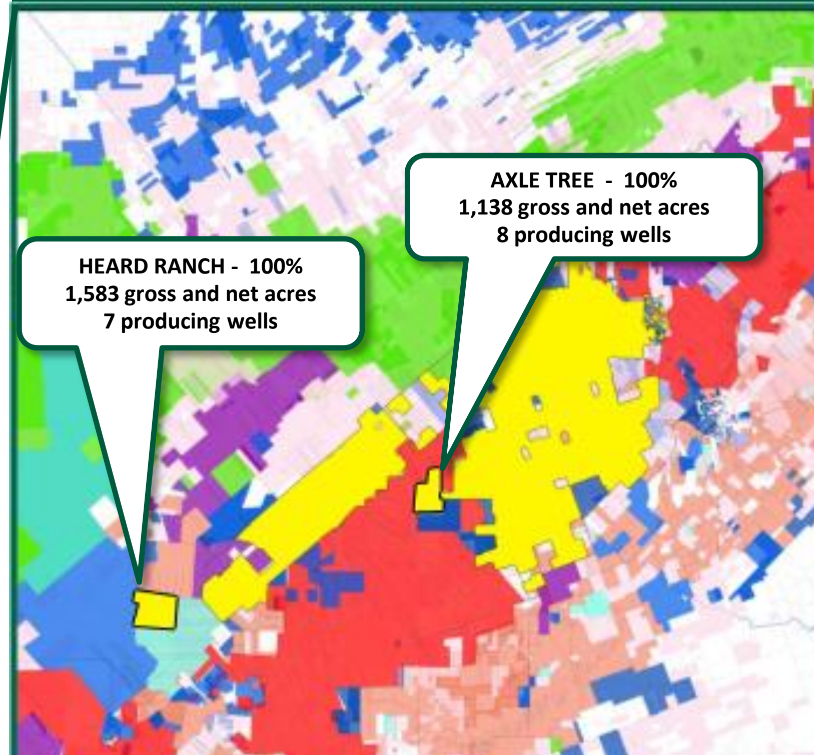
Operated Position

- **100% operated interest in 2,700 net acres in Karnes, Atascosa, and Live Oak counties**
  - All held by production
- **15 net wells on production as at Oct. 31**
- **Q3 2013 average daily gross production of 955 boe/d**
  - Offset wells shut in during fracture stimulation
  - Q3 includes a few days production from first two operated wells
- **Average 30-day IP of 821 boe/d per well (gross) on first two operated wells at Heard Ranch**
- **Production recently began on two wells at Axle Tree Ranch**
- **Original 2013 guidance of 14-19 net operated wells contemplated 4,000’ lateral lengths**
  - Longer lateral wells now being drilled
  - Estimating more total gross lateral footage with 10-12 net wells
  - Capital and operational efficiencies support enhanced economics with longer laterals



Sugarkane field

Aurora Oil & Gas [1] | ConocoPhillips | Marathon Oil | EOG Resources | Murphy Oil



Approximate leasehold positions taken from public sources or 3rd party services and websites. Working interests, acreage and well counts are as of October 31, 2013.

(1) Other than as indicated, jointly owned with Marathon Oil and others.

Operated Project Summary

- **Exploiting the knowledge gained from participation in more than 375 gross wells**
- **First 2 operated wells drilled and completed by Aurora designed for optimum performance:**
  - Pad drilling
  - Average lateral length of 7,800 ft resulting in a TMD of approximately 19,300 ft
  - Drilled more than 90% of lateral within 20 ft target zone
  - "Zipper fracced" average 31 stages per well, with 4 clusters per stage using premium Hi-WAY frac technology
  - 30-Day average IP of 821 boe/d per well (gross) of 43-44 degree API oil
  - Investment in additional data gathering and analysis yielded information to reduce future capital costs and enhance performance:
    - Pilot hole, full suite horizontal logging, tracer surveys, production logs, future planned submersible pumps
    - Well costs in-line with forecast

Non-Operated Position

- **Low risk, fully delineated Eagle Ford position**
  - ~19,400 net acres
- **WI% from 28% to 36% in Karnes, 9.1% in Atascosa, and 9.1% in Live Oak Counties**
- **Q3 2013 average daily production of 20,483 boe/d (pre-royalty), or 15,069 boe/d (post-royalty)**
- **32-35 net wells planned to be spudded in 2013**
- **25.1 net wells spudded YTD 2013**

ADDITIONAL EVALUATIONS

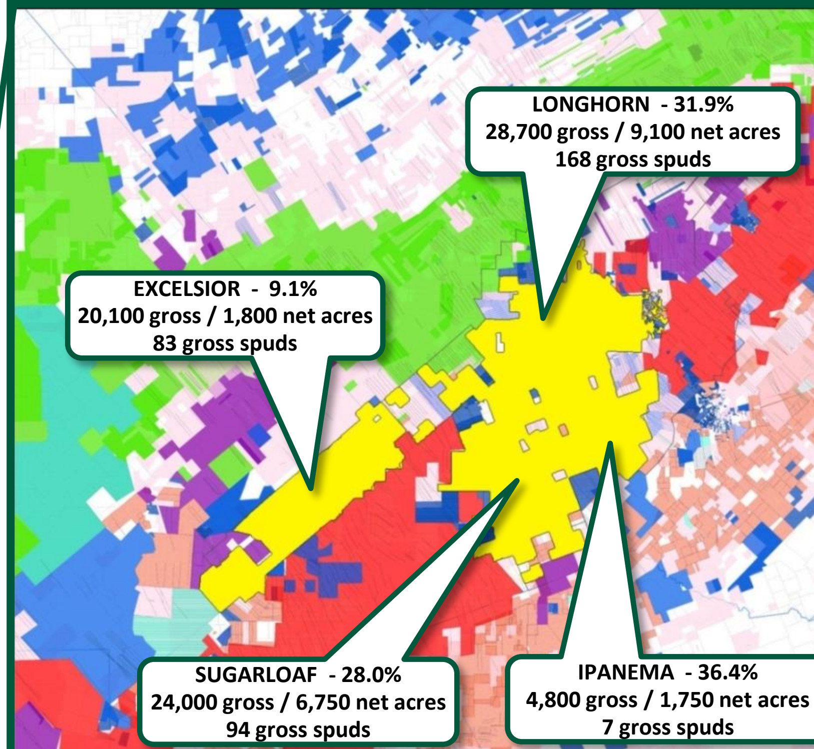
Testing 60- and 40-acre Eagle Ford spacing via multiple pilot programs

60-acre Austin Chalk pilot programs underway

Wellbore orientation, fracture stimulation techniques, production optimization

Sugarkane field

Aurora Oil & Gas [1] | ConocoPhillips | Marathon Oil | EOG Resources | Murphy Oil



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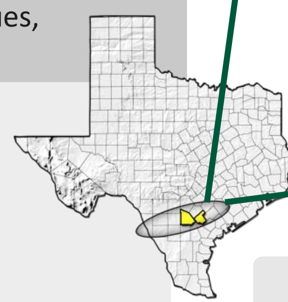
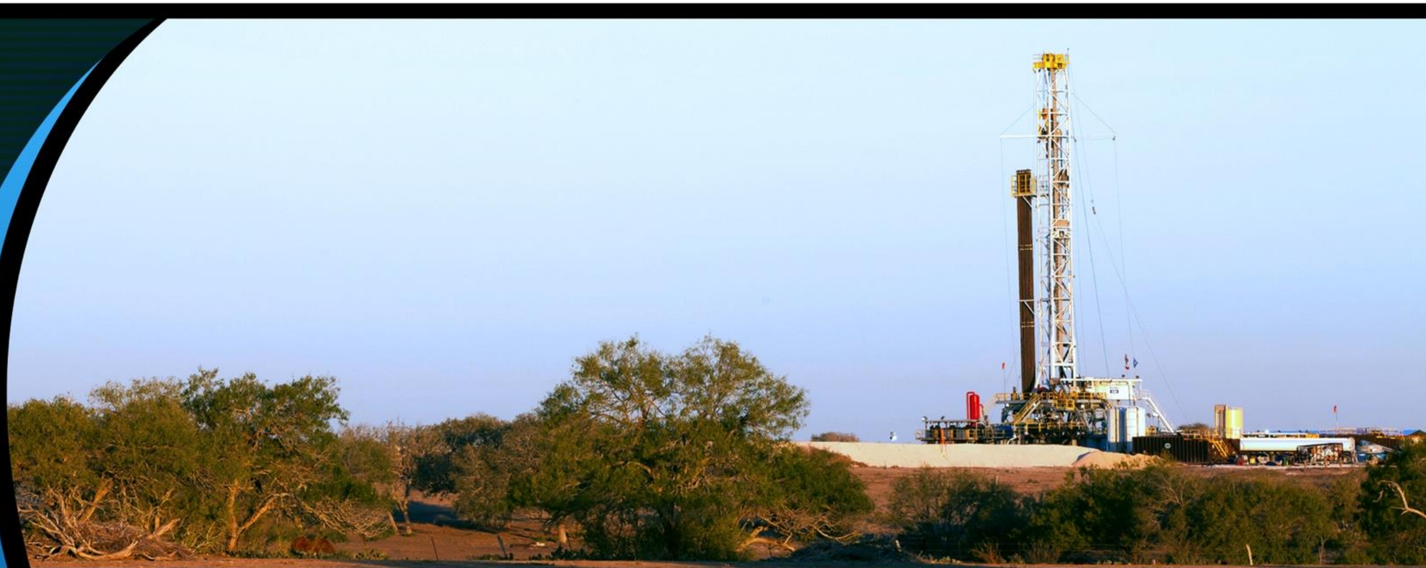


1) Jointly owned with Marathon Oil and others.

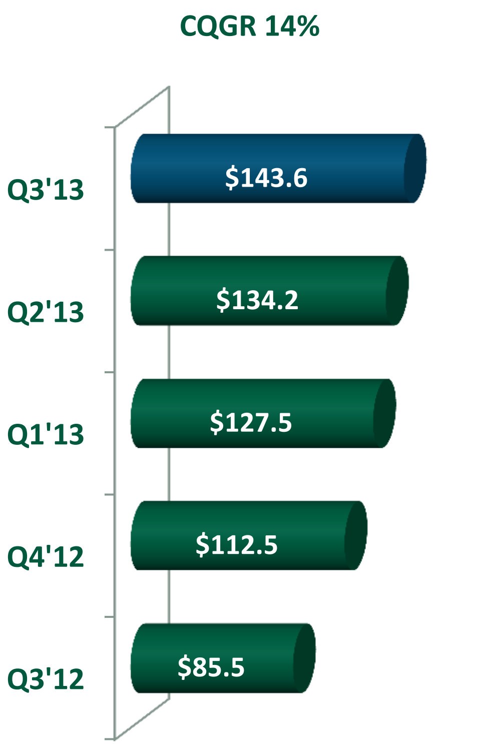


Financial Overview

Development Driving Profitability

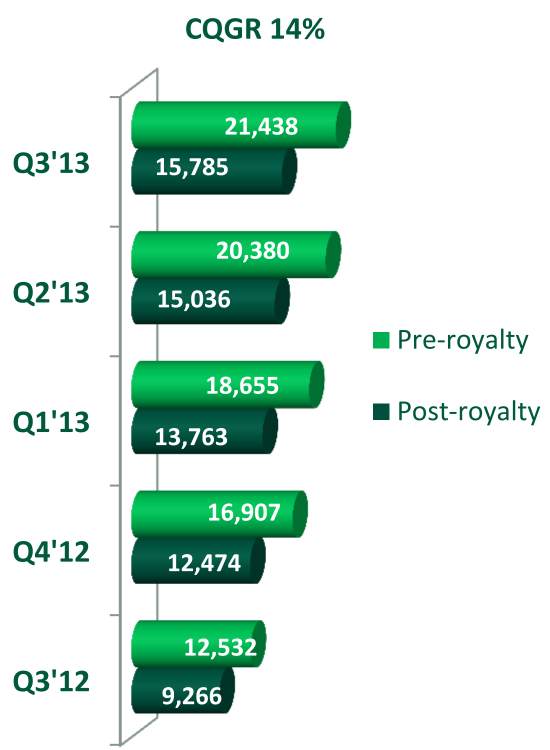
Quarter by Quarter Growth Rates

Revenue(1) (US$mm)



EBITDAX(2) (US$mm)

Average Production (boepd)



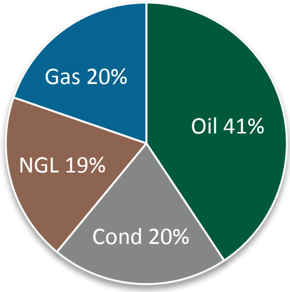
(1) Revenue from continuing operations and before royalties
(2) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

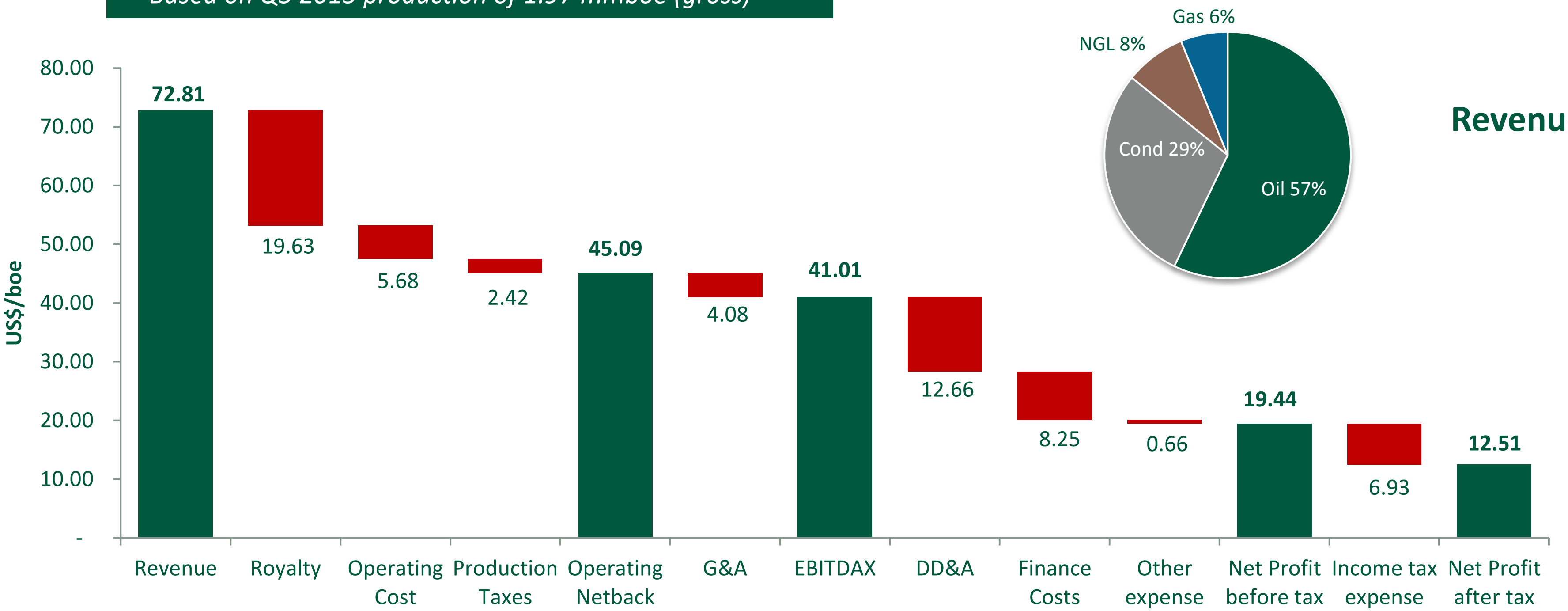
Aurora Production Mix and Netbacks – Q3 2013

High Valued, Liquids Weighted

- **Op. Netback** US$45.09/boe (gross)
- **EBITDAX**[1] US$41.01/boe (gross)
- **NPAT** US$12.51/boe (gross)

Based on Q3 2013 production of 1.97 mmboe (gross)





(1) See "Non-IFRS Financial Measures" above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices.

Netbacks – Sensitivities 2013

US$/bbl or US$/Mcf	2012 Actual	2013 Illustrative[3]					Q3 2013 Actual
WTI	94.22	100	90	80	70	60	102.56
LLS	110.66	108	98	88	78	68	109.97
Aurora realised Oil[1][2]	100.21	103.31	93.31	83.31	73.31	63.31	104.63
Aurora realised Condensate[1][2]	98.43	101.87	91.87	81.87	71.87	61.87	102.75
Aurora realised Gas	2.90	3.00	3.00	3.00	3.00	3.00	3.81
Aurora realised NGLs	32.71	30.00	30.00	30.00	30.00	30.00	30.21
Netbacks	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**S/boe**
Revenue (Blended)	75.43	77.37	71.32	65.26	59.69	54.17	72.81
Royalty	(19.86)	(20.25)	(18.49)	(16.72)	(14.95)	(13.18)	(19.63)
Operating Expense	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(5.68)
Production Taxes	(2.58)	(2.65)	(2.44)	(2.23)	(2.04)	(1.85)	(2.42
G&A Exp[4]	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(4.08)
EBITDAX[6]	**42.85**	**44.33**	**40.25**	**36.18**	**32.56**	**29.00**	**41.01**
Interest[5]	(6.28)	(7.09)	(7.09)	(7.09)	(7.09)	(7.09)	(7.51)
Other	(0.68)						(0.03)
Funds from Operations[6]	**35.80**	**37.23**	**33.16**	**29.08**	**25.46**	**21.90**	**33.47**

(1) 2012 realised average premium to WTI of US$4/bbl for condensate and US$6/bbl for oil
(2) 2013 illustrative assumed conservative premium to WTI of $1.8/bbl for condensate and US$3.3/bbl for oil
(3) 2013 illustrative figures assume production of 7.6 Mmboe (before royalty) and a similar product mix to 2012 and includes the effect of 1.1 MMbbl of crude hedging within Revenue (Blended)
(4) 2013 illustrative G&A has been maintained at the 2012 cost per boe for purposes of this illustration
(5) Financing costs for 2013 illustrative includes interest expense for all existing debt and expected drawdowns on RBL debt
(6) See “Non-IFRS Financial Measures” above. A reconciliation of net profit after tax and Funds from Operations to EBITDAX can be found in the appendices.

Well Capitalised

- Strong liquidity with US$106mm cash and an undrawn US$300mm credit facility
- No principal maturities on Senior Notes until 2017
- Maintain active commodity hedging program

US$ millions	Sep 30 2013
Cash	$ 106
Credit Facility	-
9.875 % Senior Notes due 2017	$ 365
7.50 % Senior Notes due 2020	$ 300
Total Debt	$ 665
Shareholder Equity	$ 533
Equity Market Capitalization(1)	$ 1,378
Total Debt/LTM EBITDAX(2)	2.2x
Total Debt/Annualized Q3 2013 EBITDAX	2.1x
Net Debt/Annualized Q3 2013 EBITDAX	1.7x
Interest Coverage(3)	5.5x
Total Debt/Book Capitalization	55%
Net Debt/Enterprise Value	29%

(1) Based on ASX closing price of A$3.24 per share on October 29, 2013 using an exchange rate A$1=US$0.9476
(2) See “Non-IFRS Financial Measures” above. A reconciliation of net profit after tax to EBITDAX can be found in the appendices
(3) Interest coverage is Q3 2013 EBITDAX / Q3 2013 Interest

Hedging Summary – as of October 1, 2013

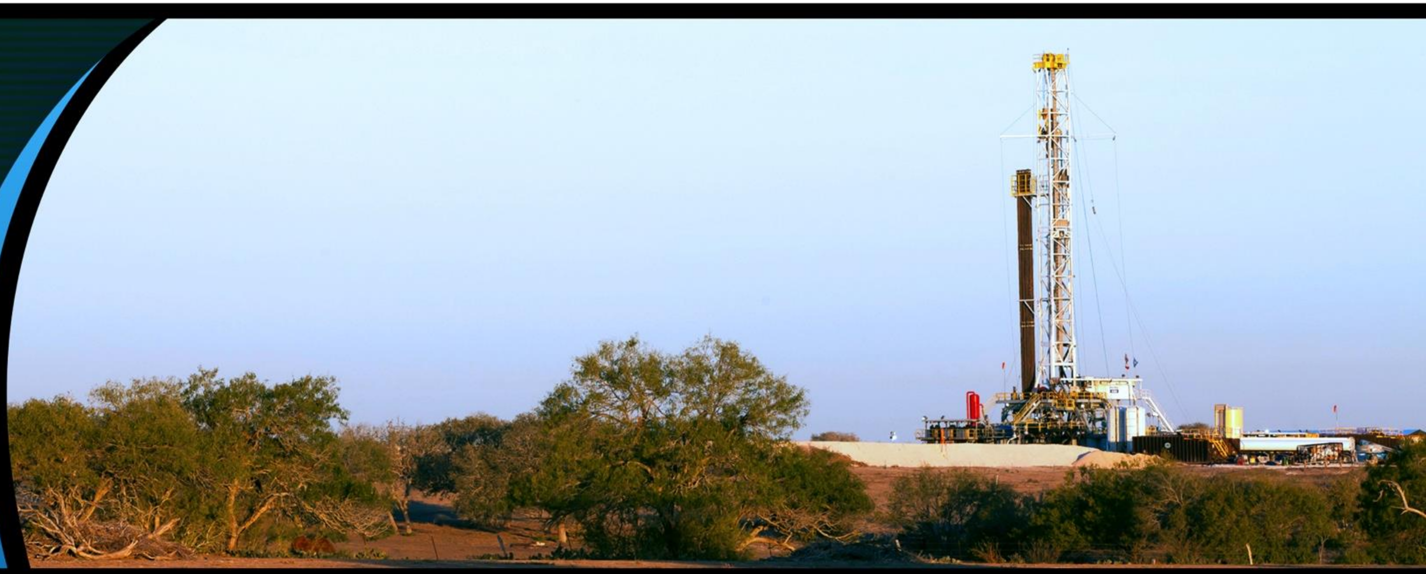
- **Aurora utilizes hedging to help preserve financial liquidity by limiting exposure to commodity price risk**

	Swaps				Collars (no premium)			Total Volume	
	WTI[1]		LLS[1]		WTI[2]			Hedged	
	Oil Hedged	Avg. Hedge Price	Oil Hedged	Avg. Hedge Price	Oil Hedged	Avg. Floor Price	Avg. Cap Price	Oil Hedged	Average
	(mbbls)	US$/bbl	(mbbls)	US$/bbl	(mbbls)	(US$/bbl)	(US$/bbl)	(mbbls)	(bbls/d)
2013 (3 months)	363.1	98.69	27.0	95.40	112.5	79.00	103.35	502.6	5,463
2014 (Full year)	1,158.3	91.81	-	-	270.0	80.00	98.67	1,428.3	3,913
2015 (Full year)	186.0	91.40	-	-	-	-	-	186.0	510
Total	**1,707.4**	**93.23**	**27.0**	**95.40**	**382.5**	**79.71**	**100.05**	**2,116.9**	

(1) Annualised hedge prices are weighted averages for the period
(2) Annualised floor and cap prices are averages for the period

Summary

- Pure Eagle Ford Shale producer
- Rapid production, revenue and profit growth
- Oil and condensate focused growth in reserves
- Strong management team and experienced partner
- Well funded with capital allocation flexibility through operated acreage
- Significant asset value



Appendices

Financial Summary – Selected Financial Data

Selected financial data

(US$ in thousands, except where noted)	Qtr Sep-12	Qtr Dec-12	Qtr Mar-13	Qtr Jun-13	Qtr Sep-13	Qtr Sep-13	12 Months to Sep-13
PRODUCTION:							
Total net production (boe) - pre-royalty	1,152,981	1,555,483	1,678,974	1,854,322	1,972,335		7,061,114
Total net production (boe) - post-royalty	852,480	1,147,650	1,238,671	1,368,246	1,452,230		5,206,797
Daily production (boe/d) - pre-royalty	12,532	16,907	18,655	20,377	21,438		19,345
Daily production (boe/d) - post-royalty	9,266	12,474	13,763	15,036	15,785		14,265
REVENUES:						US$/boe	
Oil and gas revenues	85,452	112,496	127,539	134,190	143,615	72.81	517,840
Royalties	(22,528)	(29,302)	(34,160)	(35,698)	(38,717)	-19.63	(137,877)
Net Operating Income[1]	**62,924**	**83,194**	**93,379**	**98,492**	**104,898**	**53.18**	**379,963**
EXPENSES:							
Operating expenses	(7,417)	(8,523)	(9,718)	(8,415)	(11,197)	-5.68	(37,853)
Production taxes	(2,925)	(3,859)	(4,231)	(4,512)	(4,773)	-2.42	(17,375)
Operating Netback[1]	**52,582**	**70,812**	**79,430**	**85,565**	**88,928**	**45.09**	**324,735**
Administrative expenses	(2,666)	(6,272)	(3,810)	(5,185)	(8,041)	-4.08	(23,308)
EBITDAX[1] [2]	**49,916**	**64,540**	**75,620**	**80,380**	**80,887**	**41.01**	**301,427**
Depletion, Depreciation and amortisation (non cash)	(14,117)	(15,036)	(17,915)	(22,451)	(24,978)	-12.66	(80,380)
Other income / expenses	58	37	(4)	(292)	157	0.08	(102)
Interest expense	(7,637)	(9,119)	(9,708)	(14,580)	(14,804)	-7.51	(48,211)
Amortisation of borrowing costs and premium/discounts and finance costs	(1,419)	(1,097)	(969)	(1,589)	(1,465)	-0.74	(5,120)
Share based payment expense (non cash)	(991)	(1,102)	(1,374)	(1,489)	(1,462)	-0.74	(5,427)
Exploration and evaluation costs	(887)	(1,009)	(282)	-	-	-	(1,291)
Net profit before tax	**24,923**	**37,214**	**45,368**	**39,979**	**38,335**	**19.44**	**160,896**
Income tax expense – Accrual[3]	(8,910)	(13,416)	(15,757)	(14,285)	(13,661)	-6.93	(57,119)
Net profit after tax	**16,013**	**23,798**	**29,611**	**25,694**	**24,674**	**12.51**	**103,777**

(1) See "Non-IFRS Financial Measures" above.
(2) A reconciliation of net profit after tax to EBITDAX can be found in the appendices.
(3) This represents a movement in the deferred tax provision for future taxes payable. No income tax is expected to be due/paid for 2012 or 2013 based on the current forecast plans for 2013.

Funds from Operations Reconciliation

	Three months ended			LTM
	Sep 30, 2013 US$'000	Jun 30, 2013 US$'000	Mar 31, 2013 US$'000	Sep 30, 2013 US$'000
Net profit after tax	24,674	25,694	29,611	103,777
Add/(less) non-cash items				
Depletion, Depreciation and Amortisation expense	24,978	22,451	17,915	80,380
Amortisation of borrowing costs and discount /premium on financial instruments	1,167	1,333	777	4,092
Share based payment expense	1,462	1,489	1,374	5,427
Income tax expense	13,661	14,285	15,757	57,119
Net Foreign exchange loss/(gain)	-124	362	44	296
Employee Benefit Provision	201	(13)	20	182
Funds from Operations	**66,019**	**65,601**	**65,498**	**251,273**

Funds from Operations is a supplemental measure of financial performance that is not required by, or presented in accordance with IFRS and is considered a non-IFRS measure. See "Non-IFRS Financial Measures" above.

EBITDA/EBITDAX Reconciliation

	Three months ended			LTM
	Sep 30, 2013 US$'000	Jun 30, 2013 US$'000	Mar 31, 2013 US$'000	Sep 30, 2013 US$'000
Net profit after tax	24,674	25,694	29,611	103,777
Adjustments:				
Share based payments expense	1,462	1,489	1,374	5,427
Depreciation and depletion expense	24,978	22,451	17,915	80,380
Interest income	(11)	(23)	(10)	(67)
Finance costs	16,269	16,169	10,677	53,331
Foreign exchange (gain) / loss	-124	362	44	296
Other income	(22)	(47)	(30)	(127)
Income tax expense	13,661	14,285	15,757	57,119
EBITDA	**80,887**	**80,380**	**75,338**	**300,136**
Exploration and evaluation costs	-	-	282	1,291
EBITDAX	**80,887**	**80,380**	**75,620**	**301,427**

See "Non-IFRS Financial Measures" above.