July 1, 2013

Company Announcements Platform
Australian Stock Exchange
Level 4
20 Bridge Street
SYDNEY NSW 2000

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COMPANY PRESENTATION MATERIAL – FINANCIAL REPORTING PRACTICES

In advance of the August 2013 release of its Q2 and half year results, Aurora Oil & Gas has compiled the following information for the purposes of clarifying its accounting treatment of various items.

The information pack does not represent a change in any accounting policies, nor does it contain any new material information regarding the Company's financial position, outlook or strategy.

The slides will be used for a series of Company meetings with members of the Australian investment community over the coming weeks for the purposes of providing background relevant to the Company's financial reporting practices.

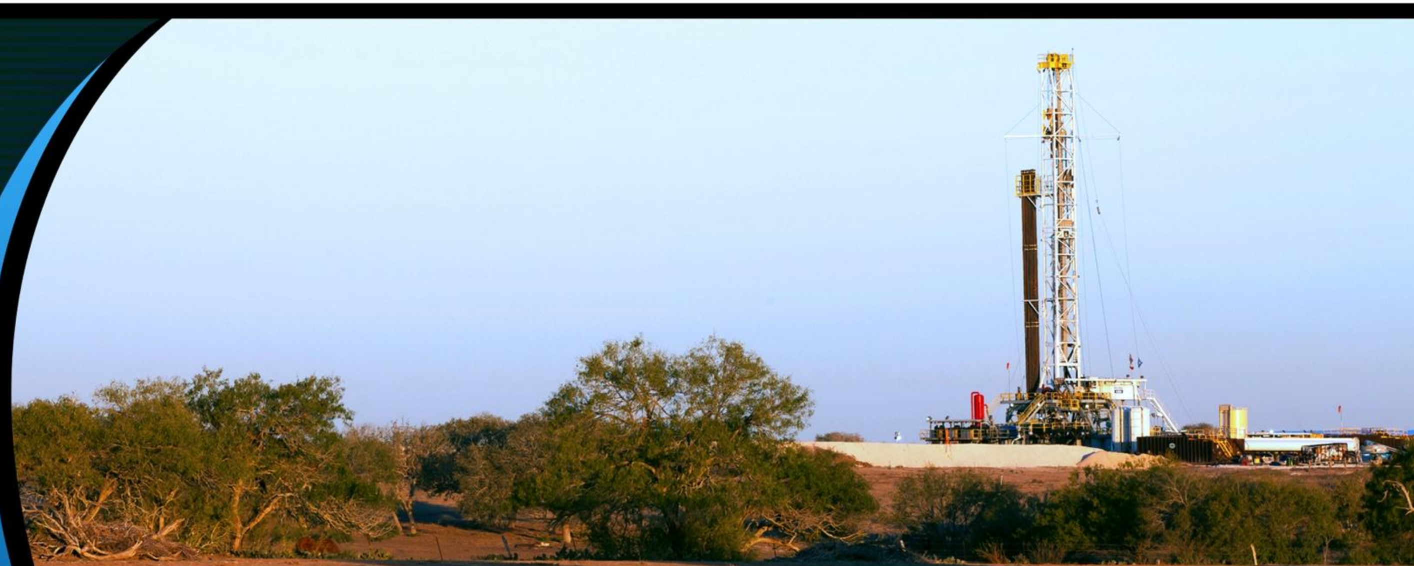
--ENDS--

For further information, please contact:

Graham Dowland	Shaun Duffy	Jane Munday
Executive Director	F T I Consulting	F T I Consulting
Aurora Oil & Gas Limited	Tel: +61 8 9485 8888	Tel: +61 8 9485 8888
Tel: +61 8 9380 2700	Mob: +61 404 094 384	Mob: +61 488 400 248
	Shaun.Duffy@fticonsulting.com	Jane.Munday@fticonsulting.com

About Aurora

Aurora is an Australian and Toronto listed oil and gas company active in the over pressured liquids rich region of the Eagle Ford shale in Texas, United States. Aurora is engaged in the development and production of oil, condensate and natural gas in Karnes, Live Oak and Atascosa counties in South Texas. Aurora participates in approximately 79,700 highly contiguous gross acres in the heart of the trend, including approximately 21,800 net acres within the Sugarkane Field in the overpressured and liquids core of the Eagle Ford.



Balance Sheet, Capital Management and Accounting Treatments/Methodologies/Policies

Disclaimers

This document has been prepared by Aurora Oil & Gas Limited ("Aurora") to provide an overview to interested analysts / investors for the sole purpose of providing preliminary background financial and other information to enable recipients to review certain business activities of Aurora. This presentation is thus by its nature limited in scope and is not intended to provide all available information regarding Aurora.

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Users of this information should make their own independent evaluation of an investment in or provision of debt facilities to Aurora.

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"Funds from Operations" and "EBITDAX" are commonly used in the oil and gas industry. Funds from Operations represent funds provided by operating activities before changes in non-cash working capital. EBITDAX represents net income (loss) for the period before income tax expense or benefit, gains and losses attributable to the disposal of projects, finance costs, depletion, depreciation and amortization expense, other non-cash charges, expenses or income, one-off or non-recurring fees, expenses and charges and exploration and evaluation expenses. The Company considers Funds from Operations and EBITDAX as key measures as both assist in demonstrating the ability of the business to generate the cash flow necessary to fund future growth through capital investment. Neither should be considered as an alternative to, or more meaningful than net income or cash provided by operating activities (or any other IFRS financial measure) as an indicator of the Company's performance. Because EBITDAX excludes some, but not all, items that affect net income, the EBITDAX presented by the Company may not be comparable to similarly titled measures of other companies.

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; Defined Terms

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 reserves in this presentation have been prepared or evaluated in accordance with the COGE Handbook effective as of 31 December 2012, and are derived from the January 30, 2013 reserves report as at December 31, 2012 as 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 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.
- “EUR” means Estimated Ultimate Recovery

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
- “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.

Balance Sheet – Debt

Notes – unsecured

- "2017 Notes" - US$365 mm at 9.875% pa due Feb 2017
- "2020 Notes" - US$300 mm at 7.50% pa due April 2020
- Notes are fixed term and fixed coupon debt
- Semi annual interest payments
- Issued to over 80 institutional bond investors
- Less restrictive on Aurora's business or assets than bank facilities – covenant light
- No equity conversion rights

Reserve Based Borrowing (Revolver) – secured

- US$200 mm available to draw down from a syndicate of US and international banks
- Currently undrawn
- Floating interest rate – LIBOR plus 2% - 3%
- Flexible financing – draw and repay at any time
- Borrowing base grows in line with value of producing and proven reserves, reset semi-annually
- Financial covenants – includes cashflow and earnings to interest, and total debt

Debt

In 2011 Aurora secured a revolving credit facility to fund its Sugarkane drilling program and for general corporate purposes. In 2012 and 2013 Aurora raised unsecured debt primarily to fund acquisitions and / or field development. The debt position as at March 31, 2013 consists of:

Type	Instrument	Principal Loan ("face value")	Term	Due date	Issue price[1]	Interest[2]	Borrowing base
2017 Notes - Initial issue	Senior unsecured notes	US$200 million	5 years	February 2017	Discount – 98.552% of face value	9.875% pa expensed on a straight line basis, payable twice yearly in arrears.	N/A
2017 Notes - Follow on issue	Senior unsecured notes	US$165 million	4.4 years	February 2017	Premium – 101.5% of face value	9.875% pa expensed on a straight line basis, payable twice yearly in arrears.	N/A
2020 Notes	Senior unsecured notes	US$300 million	7 years	April 2020	At par – 100% of face value	7.50% pa expensed on a straight line basis, payable twice yearly in arrears.	N/A
Reserve based revolving credit facility (RBL)	Senior secured credit facility	US$200 million (undrawn at March 31, 2013)	5 years	November 2016	N/A	A margin of between 2% and 3% over the floating LIBOR rate on a straight line basis	Borrowing base grows in line with value of producing and proven reserves

- The discount or premium on issue of senior unsecured notes is capitalised to borrowings (non-current liabilities) and amortised over the loan term.
- Please refer to slide "Finance Costs – Interest Expense Calculation" below for the calculation of interest expense recognised in the statement of profit or loss and other comprehensive income.

Debt

Accounting treatment of debt components:

Component	Statement of Financial Position	Statement of profit or loss and other comprehensive income
Principal	Non-current liability - Borrowings	N/A
Borrowing costs[1]	Capitalised to either non-current assets: Oil and gas properties[2] OR non-current liability: Borrowings[2]. Costs are amortised on a straight line basis over the loan term.	Borrowing costs are amortised on a straight line basis over the loan term to the "Finance Costs" expense line item.
Discount / premium to face value (Notes only)	Initially capitalised to non-current liabilities: Borrowings. This amount is amortised on a straight line basis over the loan term.	The capitalised discount / premium is amortised on a straight line basis over the loan term and included in the "Finance Costs" expense line item.
Interest	N/A	Interest expense is recognised in the "Finance Costs" expense line item on a straight line basis over the loan term (Notes) and in the related accounting period of a drawn balance at a margin of between 2%-3% pa equivalent on the drawn balance for RBL.
Commitment fee (RBL only)	N/A	Expensed to Finance Costs: Other financing fees. Calculated at 0.5% of the undrawn balance quarterly

1) Borrowing costs include commissions, advisory fees and other offering costs.

2) In accordance with AASB 123: Borrowing Costs, Aurora is permitted to capitalise borrowing costs to Non-current assets: Oil & gas properties where the funds borrowed are used directly for the acquisition or construction of oil & gas properties (Initial 2017 Notes, 2020 Notes and initial RBL set up). If funds raised are not associated with an asset acquisition then borrowing costs are capitalised to Non-current liability: Borrowing (2017 follow on issue and subsequent RBL redeterminations).

Balance Sheet Management

Financial Liquidity

March 31, 2013	US$ Millions
Cash on hand	177
Trade and other receivables	72
Trade and other payables	(160)
Working capital as at March 31, 2013	89
Revolving credit facility availability	200
Financial Liquidity	**289**

- Funding in place exceeds forecast working capital requirements and capital forecast
- RBL in place at US$200 mm (undrawn)
- US$115 mm of the 2020 Notes proceeds used to complete Q1 2013 acquisition

RBL - Borrowing Base Availability

- RBL facility established at US$300 mm
- Current amount available for borrowing (“Borrowing Base”) is US$200 mm
- The current Borrowing Base was reset in Q1 2013 based on the value of proven reserves as at Dec 31, 2012 and reflecting the March 2013 senior unsecured Note issue (2020 Notes), but excluded the value of the proven reserves associated with the March 2013 acquisition
- RBL facility generally grows proportionately with the pre tax NPV10 value of proven reserves (with a higher weighting to producing reserves) less approx 25% of the total amount of senior unsecured borrowings (face value of Notes on issue)
- A mid year 2013 redetermination will occur in Q3 2013 to reflect:
    - The updated estimated value of proven and producing reserves as at June 30, 2013, taking into account the new wells placed on production at the Sugarkane Field in the H1 2013 on the non operated acreage
    - The value of the proven and producing wells at the Sugarkane Field operated acreage as at June 30, 2013

Finance Costs - Interest Expense Calculation Example

Inputs based on Q1 2013 actual results

2017 Notes

A. Principal – US$365 mm
B. Interest rate – 9.875% pa
C. Days in current period (Q1 2013) – 90 days

2020 Notes

D. Principal – US$200 mm
E. Interest rate – 7.5% pa
F. Days in current period (Q1 2013) – 9 days[1]

Reserve Based Borrowing (RBL)

G. Principal A – US$30 mm
H. Principal A - Days in current period – 84 days
I. Principal B – US$30 mm
J. Principal B - Days in current period – 32 days
K. Interest rate – LIBOR plus between 2% and 3% pa

1) *The 2020 Notes offering was completed on March 21, 2013, resulting in interest being incurred for 9 days during Q1 2013.*

Interest expense calculation examples

2017 Notes
= (A x B x C) / 365 days
= (US$365 mm x 9.875%) x (90 / 365)
= US$8.9 mm

2020 Notes
= (D x E x F) / 365 days
= (US$200 mm x 7.5%) x (9 / 365)
= US$0.4 mm

RBL
Principal A:
An initial US$30 mm was drawn on Nov 21, 2012 and repaid on March 25, 2013.
= (G x H x I) / 360* days
= (US$30 mm x 2.31%) x (78 / 360) plus
(US$30 mm x 2.56%) x (6 / 360)
= US$0.2 mm

Principal B:
A second drawdown of US$30 mm was made on Feb 21, 2013 and repaid on March 25, 2013.
= (I x J x K) / 360* days
= 1. (US$30 mm x 2.46%) x (6 / 360)
2. (US$30 mm x 2.21%) x (26 / 360)
= US$0.1 mm

** interest is calculated pa over 360 days.*

Balance Sheet - Debt Metrics as of Q1, 2013

Continued quarter on quarter production and earnings growth strengthens debt metrics on existing long term unsecured debt.
Long term debt repayments structured for well after project capacity for repayment out of free cash.

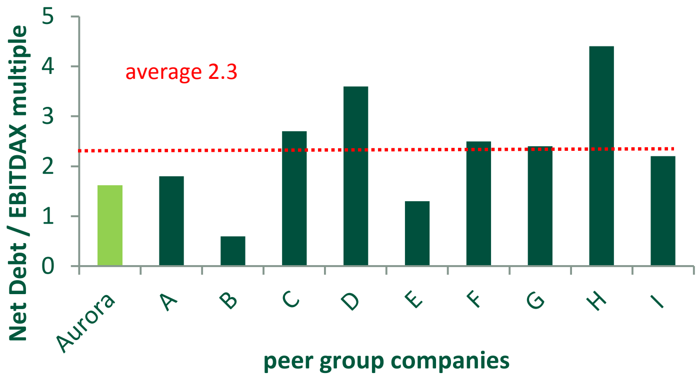
	Inputs	US$mm
	Interest	
A	Q1 2013 interest costs	9.7
B	2013 fixed interest costs	53
	EBITDAX	
C	Q1 2013	75.6
D	Annualised Q1 2013 (C x 4)	302
E	Last 12 months (LTM) – Q2 12 to Q1 13	222
	Debt – March 31, 2013	
F	Total debt	665
G	Net debt (Total debt less cash)	488

Metrics		Multiple
Debt to EBITDAX		
Total debt to annualised Q1 2013 EBITDAX	F / D	2.2x
Total debt to LTM EBITDAX	F / E	3.0x
Net debt to annualised Q1 2013 EBITDAX	G / D	1.6x
Net debt to LTM EBITDAX	G / E	2.2x
Interest Cover		
Q1 2013 EBITDAX to Q1 2013 interest	C / A	7.8x
Annualised Q1 2013 EBITDAX to 2013 fixed interest	D / B	5.7x

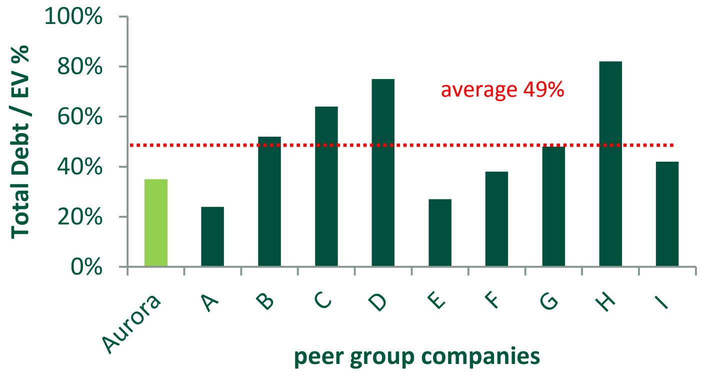
1) EBITDAX is a supplemental measure of financial performance that is not required by, or presented in accordance with IFRS and is considered a non-IFRS measure. See “Non-IFRS Financial Measures” in the disclaimers . A reconciliation of net earnings after tax to EBITDAX is detailed in the appendices

Debt Metrics – Peer Group Comparison – Q1 2013

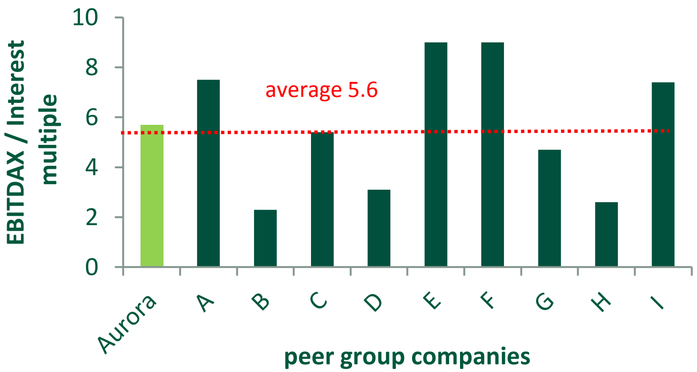
Net Debt / EBITDAX (annualised)



Total Debt / EV



Interest Cover Ratio



For the purposes of these comparisons the following information is provided:

Total Debt:	Reported as at March 31, 2013
Net Debt:	Total debt less reported cash on hand as at 31 March, 2013
EBITDAX :	Reported Q1 2013 EBITDAX, annualised
Interest :	Reported Q1 2013 interest expense annualised, except that Aurora uses estimated fixed interest costs for 2013
EV :	Enterprise value calculated using net debt as described above and market cap at May 9, 2013

Refer to the following slides for details of peer group companies

EBITDAX 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" in the disclaimers . A reconciliation of net earnings after tax to EBITDAX is detailed herein. Other companies in the peer group may not calculate EBITDAX in an identical manner.

Debt Peer Group Summary Information

Name	Aurora	Carrizo	Forest	Kodiak	Oasis	Penn Virginia	PetroQuest	Rosetta	Sanchez	Swift
Ticker NYSE/NASDAQ		CRZO	FST	KOG	OAS	PVA	PQ	ROSE	SN	SFY
Project Locations	Eagle Ford	Barnett, Niobrara, Marcellus	Texas Panhandle, East Texas	Williston Basin	Williston Basin	Mid-Continent, Haynesville, Selma Chalk, Marcellus	East Texas, Gulf Coast/GOM, Mid-Continent	Permian Basin	Eagle Ford, Haynesville, Heath, Bakken, Three Forks	Central and Southeast Louisiana
Market Cap (US$MM) (May 9, 2013)	1,427	1,102	590	2,224	3,468	301	304	2,861	684	569
Production Q1 2013 (net MMboe)	1.2	2.4	3.6	2.0	2.7	1.4	1.4	4.2	0.4	2.8
% Liquids in Q1 2013 production	80%	39%	34%	88%	91%	58%	9.1%	62%	90%	55%

Capital Expenditure – Balance Sheet Items

The following table summarises each component of oil and gas properties at March 31, 2013

	Original asset value Jan 1, 2011	Subsequent acquisition costs 2011-2013	Uplift recognised on acquisition 2013	Drilling / completion costs Since Jan 1, 2011		Facilities construction cost	Rehabilitation	Borrowing costs[2]	Accumulated DDA	Carrying value at March 31, 2013
				Producing	WIP[1]					
(US$ millions)										
Producing assets	137.0	256.4	48.0	559.2	40.4	-	2	17	(57.7)	**1,002.3**
Development assets[3]	-	72.8	-	-	-	-	-	-	-	**72.8**
Production facilities and field equipment	-	4.0	-	23.0	-	59.0	-	-	(5.7)	**80.3**
Balance at March 31, 2013	**137.0**	**333.2**	**48.0**	**582.2**	**40.4**	**59.0**	**2**	**17**	**(63.4)**	**1,155.4**
Expense allocation method	Depletion	Depletion or depreciation. N/a for development assets.	Depletion	Depletion	N/a until completed and producing	Depreciation	Depletion	Amortisation		

1) Represents drilling and completion costs incurred in respect of wells that have commenced operation (spud) but not yet on production
2) In accordance with AASB 123: Borrowing Costs, when an entity borrows funds specifically for the purposes of obtaining and developing a particular qualifying asset, the borrowing costs that directly relate to that qualifying asset are eligible for capitalisation
3) Development assets represents the value attributed to assets which have not yet commenced commercial production (generally acquisition value or costs of successful exploration). As development occurs and the asset or a portion thereof begins producing commercial volumes, the value is transferred to producing assets and depletion commences

Depreciation, Depletion & Amortisation (DDA)

	Asset class impacted	Method	DDA term
Depreciation	Production facilities (property, plant and equipment)	Reducing balance	Useful life of 15 years
	Field equipment (property, plant and equipment)	Reducing balance	Useful life of 5 years
	Office equipment (property, plant and equipment)	Straight line	Useful life of between 2 years and 10 years
Depletion	Oil and gas properties – producing projects including rehabilitation, however excluding drilling and completion WIP (wells not yet on production)	Units of production at AMI level[1]	Proved plus probable (2P) reserve base
Amortisation	Borrowing costs – either capitalised to (1) oil and gas properties or (2) capitalised to Borrowings	Straight line	Loan term

1) Unit of production method of depletion - based on usage. Depletion for a period calculated as follows:
Depletion rate (asset cost divided by remaining recoverable 2P reserves at the beginning of the period) multiplied by the volume produced in the period

Depletion calculation

Inputs

A. Carrying value of producing assets
+ rehabilitation
- capitalised WIP drilling and completion

B. Cumulative production at period end

C. Total proved + probable (2P) reserve base

D. Opening accumulated depletion.

Calculation example inputs – Example AMI
(for illustration purposes only)

	Asset AMI 1	Asset AMI 2
A.	US$140m	US$300m
B.	950,000 boe	520,000 boe
C.	19,000,000 boe	14,000,000 boe
D.	US$5.0m	US$7.0m

Calculation

AASB 138: Intangible assets requires that depletion be calculated on the smallest identifiable area of interest. For Aurora this is determined to be AMI level.

Accumulated depletion calculation (per AMI):

= (A / C) x B

Depletion expense per period (per AMI):

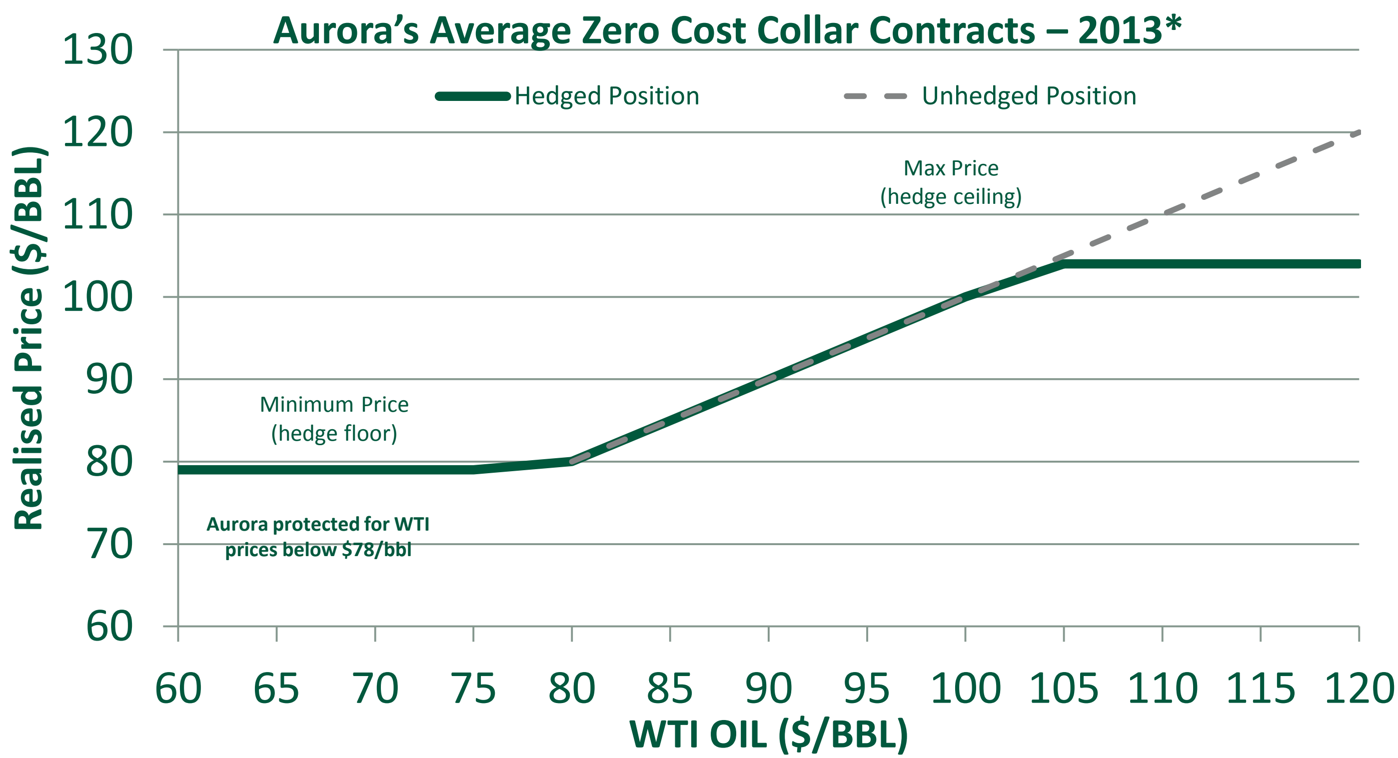
= ((A / C) x B) – D

Calculation example – Example AMI:

	Calculation	Accumulated depletion	Depletion expense
Asset AMI 1	(US$140mm / 19mmboe) x 0.95mmboe	US$7.0mm	
	((US$140mm / 19mmboe) x 0.95mmboe) – US$5mm		US$2.0mm
Asset AMI 2	(US$300mm / 14mmboe) x 0.52mmboe	US$11.1mm	
	((US$300mm / 14mmboe) x 0.52mmboe) – US$7mm		US$4.1mm

Hedging - Objectives

- Current hedging strategy is to ensure adequate coverage, on an after cash cost basis, [1] over interest expenses for an 18 month look forward period
- Aurora uses calendar swaps and zero cost collars against WTI and LLS markers



- Average across 2013 contracts

1) After cash costs means after royalties, opex and G&A

Hedging Summary – as of July 1, 2013

	Swaps				Collars (no premium paid)			Total Volume	
	WTI		LLS		WTI			Hedged	
	Oil Hedged	Avg. Hedge Price	Oil Hedged	Avg. Hedge Price	Oil Hedged	Avg. Floor Price	Avg. Cap Price		
	(mbbls)	US$/bbl	(mbbls)	US$/bbl	(mbbls)	(US$/bbl)	(US$/bbl)	(mbbls)	Average (bbls/d)
2013 (6 months)	234	93.0	54	95.4	225	79.0	103.4	513	2,800
2014 (Full year)	840	90.5	-	-	270	80.0	98.7	1,110	3,040
Total	**1,074**		**54**		**495**			**1,623**	

Hedgebook – 2013 & 2014

Full Year

	Swaps						Zero Cost Collars			
	WTI			LLS			WTI			
	Oil hedged (mbbls)	Hedge price (US$/bbl)	Gross value (US$mm)	Oil hedged (mbbls)	Hedge price (US$/bbl)	Gross value (US$mm)	Oil hedged (mbbls)	Floor price (US$/bbl)	Cap price (US$/bbl)	Gross value (US$mm)
2013	342	92.8	31.7	108	95.4	10.3	405	78.9	103.5	32
2014	840	90.3	76.0	-	-	-	270	80.0	98.7	22
Totals	**1,182**		**107.7**	**108**		**10.3**	**675**			**54**

Look Forward July 2013

	Swaps						Zero Cost Collars			
	WTI			LLS			WTI			
	Oil hedged (mbbls)	Hedge price (US$/bbl)	Gross value (US$mm)	Oil hedged (mbbls)	Hedge price (US$/bbl)	Gross value (US$mm)	Oil hedged (mbbls)	Floor price (US$/bbl)	Cap price (US$/bbl)	Gross value (US$mm)
2013	234	93.0	21.8	54	95.4	5	225	79.0	103.4	18
2014	840	90.3	76.0	-	-	-	270	80.0	98.7	22
Totals	**1,074**		**97.8**	**54**		**5**	**495**			**40**

Hedge Accounting

Accounting treatment of hedges designated as derivative financial instruments:

Component	Valuation method	Position	Statement of profit or loss and other comprehensive income	Statement of Financial Position
Settlement of hedge contracts	Settlement is calculated as the difference between the monthly float rate and the hedged price, multiplied by the number of barrels hedged.	In the money	Settlement proceeds increase Income: *Revenue from continuing operations*.	Settlement proceeds increase Current Assets: *Cash and cash equivalents increase*.
		Out of the money	Settlement payment decreases Income: *Revenue from continuing operations*.	Settlement payment decreases Current Assets: *Cash and cash equivalents decrease*.
Valuation of future hedge contracts	At reporting date hedge contracts settling in future periods are marked to market.	In the money	N/a	Revaluation will increase Current Assets: *Derivative financial instruments* (if settlement is within 12 months of reporting date), or Non-current Assets: *Derivative financial instruments* (if settlement is after 12 months of reporting date) and increase Equity: *Cash flow hedge reserve.*
		Out of the money	N/a	Revaluation will decrease Current Liabilities: *Derivative financial instruments* (if settlement is within 12 months of reporting date), or Non-current Liabilities: *Derivative financial instruments* (if settlement is after 12 months of reporting date) and decrease Equity: *Cash flow hedge reserve.*

Mineral Leases and Royalties

- Minerals rights in Texas are private property rights owned by individual(s) or entities.
- E&P companies negotiate with mineral rights owners for the right to drill and produce hydrocarbons under a mineral lease.
- Aurora has an interest in over 1200 mineral leases
- Every mineral lease has unique terms and conditions which govern exploration and development operations.
- A typical lease would compensate the mineral rights owner with:
  - A one-time per acre upfront bonus cash payment, and
  - An on-going royalty payment of either (a) a share of production from the mineral interest or (b) a share of the proceeds of such production.
- The royalty rate is a negotiated item, but generally is in the 20-30% range.
- Aurora's average royalty rate burden on non operated acreage is 26% and on operated acreage is 25%.
- The primary term of a mineral lease will generally expire after three years unless extended by either further payment or by undertaking specified drilling and development activity.
- Typically, once a well has been drilled and placed on production, a certain defined area with the mineral lease rights are "held by production" (HBP) for the production life of the well – extending the term of the lease for that area and generally, other than payment of the royalty from the lessors share of production, no further obligations exist whilst the lease is HBP.
- The Railroad Commission of Texas designates the HBP characteristics for the field, however mineral owners can agree variations from Commission designations in certain circumstances.
- Over 95% of the leases in which Aurora has an interest are HBP.
- Royalty owners are not required to contribute to capex or opex in the exploration and development of their mineral interests, which costs are borne by the working interest owners that have obtained a mineral lease.

Operating Expenses

- **US onshore Texas and local county fiscal regime is characterised by the following production based, variable and fixed expenditures:**
- **Severance Taxes**
  - Severance taxes are paid prior to deduction of royalty interests and are assessed as follows:
    - oil and condensate at 4.6% of the gross sales value,
    - gas at 7.5% (a rebate is received – effective rate approx 2%) on the well head net back equivalent price, and
    - NGLs at 7.5% on the well head net back equivalent price.
- **Ad Valorem Taxes**
  - Ad valorem taxes are levied, prior to deduction of royalty interests, by the local county.
  - For modelling purposes, it is suggested that 2% of oil and gas revenue be used.
- **Fixed and Variable Lease operating expenses**
  - Lease operating expenses are the costs of maintaining and operating property and equipment on a producing oil and gas lease.
  - Variable (direct) lease operating expenditures include transportation, insurance and utilities. Fixed lease operating expenditures include labour and road, site and facility maintenance, and repairs.

Corporate Tax

- **Consolidated Corporate Income Tax**
- Tax expense in the statement of profit or loss represents:
  - Current tax: the amount of income taxes payable in respect of the taxable profit for the period and / or
  - Deferred tax: the amount of income taxes payable or recoverable in future periods

  Currently only deferred tax is represented in the consolidated statement of profit or loss and other comprehensive income.
- Income tax is not currently payable due to accumulate losses (NOLs) and deductible capital expenditure (primarily development drilling)
- "Taxable Profit" represents accounting profit which has been adjusted in accordance with the rules established by the relevant taxation authorities

Corporate Tax

US corporate income tax

- US corporate income tax rate is 35% of Taxable Profit
- For Aurora, the most significant difference between accounting and tax treatment is the acceleration of the deduction for tax purposes of capital expenditures.
- Therefore in Aurora's financials:

Taxable Profit =	Accounting profit
add back:	Accounting depletion, depreciation and amortisation
then subtract:	Intangible drilling costs (IDC)
	Depletion for taxation purposes of accumulated leasehold costs
	Depreciation for taxation purposes of accumulated tangible drilling costs
	Depreciation for taxation purposes of accumulated property, plant & equip cost (PPE)
	Accumulated losses (NOLs)

- As the NOLs are utilised and taxable profits before capex adjustments offsets increase, it is likely that the "Alternative Minimum Tax" rules will require income tax to be prepaid in the US, albeit at a reduced effective rate (i.e. less than 35%)

Corporate Tax - Continued

Capital Expenditures:	Leasehold costs	Intangible Drilling Costs	Tangible Drilling Costs (e.g. well casing)	Plant & Equipment "PP&E" costs (e.g. Surface Equip and Facilities)
Cost Basis	Acquisition cost	Guide to approx 80- 90% of well cost	Guide to approx 5-10% of well cost	Guide to approx 5-10% of well cost and total cost of central gathering facilities
Accounting Treatment	Depletion based on UOP - 2P reserves	Depletion based on UOP - 2P reserves	Depletion based on UOP - 2P reserves	5-25 years reducing balance
Tax Treatment	Depletion based on UOP – 1P reserves	Full (100%) deduction in year incurred	Typically 7 years Double Declining Balance	Typically 7 years Double Declining Balance

UOP – means Units of Production.

Double Declining Balance – is a form of accelerated depreciation whereby 200% of the straight line depreciation rate is applied to the assets carrying value (cost less accumulated depreciation) at the beginning of each period.

Corporate Tax - Continued

Australian Corporate Income Tax

- Australian corporate taxation rate is 30%.
- Limited assessable income in Australia, therefore no or immaterial tax implications in Australia.
- Accumulated carry forward losses in Australia are not brought to account in Aurora's financials on the basis that they are not expected to be recoverable in the foreseeable future.
- Funds flow from the US to Australia from any future dividends or return on capital are not taxable under the tax treaty with the US.

Netbacks – Sensitivities 2013

	2012	2013 Illustrative					Q1 2013
US$/bbl or US$/Mcf							
WTI	94.22	100	90	80	70	60	94.30
LLS	110.66	113	103	93	83	73	114.40
Realised Oil [(1) (2)]	100.21	105	95	85	75	65	105.29
Realised Condensate[(1) (2)]	98.43	103	93	83	73	63	101.52
Realised gas	2.90	3.00	3.00	3.00	3.00	3.00	3.67
Realised NGLs	32.71	30	27	24	21	18	33.00
Netbacks	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**	**$/boe**
Revenue (Blended) [(3)]	75.43	78.56	71.78	64.99	58.69	52.46	75.96
Royalty	(19.86)	(20.57)	(18.67)	(16.76)	(14.85)	(12.94)	(20.34)
Opex	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(6.27)	(5.79)
Production Taxes	(2.58)	(2.69)	(2.46)	(2.22)	(2.01)	(1.79)	(2.52)
G&A Exp [(4)]	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(3.87)	(2.27)
EBITDAX [(6)]	**42.85**	**45.16**	**40.52**	**35.87**	**31.70**	**27.59**	**45.04**
Interest [(5)]	(6.96)	(7.09)	(7.16)	(7.23)	(7.29)	(7.36)	(6.36)
Funds from Operations [(6)]	**35.89**	**38.07**	**33.36**	**28.64**	**24.41**	**20.23**	**38.68**

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 US$3/bbl for condensate and US$5/bbl for oil
3) 2013 illustrative figures assume production of 7.6 MMboe (before royalty), a similar product mix to 2012 and includes the hedging effect of hedges as at 31 March 2013
4) 2013 illustrative G&A has been maintained at the 2012 cost per boe for purposes of this illustration
5) Interest costs for 2013 illustrative includes interest expense for all existing debt and expected drawdowns on RBL facility
6) EBITDAX and Funds from Operations are supplemental measures of financial performance that are not required by, or presented in accordance with IFRS and are considered non-IFRS measures. See “Non-IFRS Financial Measures” in the disclaimers.

Financial Summary – Selected Financial Data

Selected financial data

(US$ in thousands)	Qtr Jun-12	Qtr Sep-12	Qtr Dec-12	Qtr Mar-13	Qtr Mar-13	12 Months to Mar-13
PRODUCTION:						
Total net production (boe) - pre-royalty	761,135	1,152,981	1,555,483	1,678,974		5,148,573
Total net production (boe) - post-royalty	559,438	852,480	1,147,650	1,238,671		3,798,239
Daily production (boe/d) - pre-royalty	8,364	12,532	16,907	18,655		14,106
Daily production (boe/d) - post-royalty	6,148	9,266	12,474	13,763		10,406
REVENUES:					US$/boe	
Oil and gas revenues	57,341	85,452	112,496	127,539	75.96	382,828
Royalties	(15,403)	(22,528)	(29,302)	(34,160)	(20.35)	(101,393)
Net Operating Income [1]	**41,938**	**62,924**	**83,194**	**93,379**	**55.62**	**281,435**
EXPENSES:						
Operating expenses	(4,999)	(7,417)	(8,523)	(9,718)	(5.79)	(30,657)
Production taxes	(1,907)	(2,925)	(3,859)	(4,231)	(2.52)	(12,922)
Operating Netback [1]	**35,032**	**52,582**	**70,812**	**79,430**	**47.31**	**237,856**
Administrative expenses	(3,393)	(2,666)	(6,272)	(3,810)	(2.27)	(16,141)
EBITDAX [1] [2]	**31,639**	**49,916**	**64,540**	**75,620**	**45.04**	**221,715**
Depletion, Depreciation and amortisation (non cash)	(7,250)	(14,117)	(15,036)	(17,915)	(10.67)	(54,318)
Other income / expenses	5,063	58	37	(4)	(0.00)	5,154
Interest expense	(4,910)	(7,637)	(9,119)	(9,708)	(5.78)	(31,374)
Amortisation of borrowing costs and premium/ discounts and finance costs	(612)	(1,419)	(1,097)	(969)	(0.58)	(4,097)
Share based payment expense (non cash)	(1,078)	(991)	(1,102)	(1,374)	(0.82)	(4,545)
Exploration and evaluation costs	(2,564)	(887)	(1,009)	(282)	(0.17)	(4,742)
Net profit before tax	**20,288**	**24,923**	**37,214**	**45,368**	**27.02**	**127,793**
Income tax expense – Accrual [3]	(9,958)	(8,910)	(13,416)	(15,757)	(9.38)	(48,041)
Net profit after tax	**10,330**	**16,013**	**23,798**	**29,611**	**17.64**	**79,752**

1) EBITDAX , operating netback and net operating income are supplemental measure of financial performance that are not required by, or presented in accordance with IFRS and are considered non-IFRS measures. See "Non-IFRS Financial Measures".
2) A reconciliation of net profit after tax to EBITDAX is included herein.
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.

EBITDA/EBITDAX Reconciliation

	Three months ended		LTM	Year ended
	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000
Net profit after tax	29,611	23,798	79,752	58,846
Adjustments:				
Share based payment expense	1,374	1,102	4,545	4,398
Depletion, depreciation and amortisation expense	17,915	15,036	54,318	39,161
Interest income	(10)	(23)	(216)	(247)
Finance costs	10,677	10,216	35,471	28,027
Net foreign exchange (gain)/ loss	44	13	(2,942)	(3,042)
Gain on foreign currency derivatives not qualifying as hedge	0	0	(1,167)	(1,167)
Other income	(30)	(28)	(59)	(29)
Net gain on sale of available for sale assets	0	0	(770)	(770)
Income tax expense	15,757	13,416	48,040	37,356
EBITDA	**75,338**	**63,530**	**216,972**	**162,533**
Exploration and evaluation costs	282	1,009	4,742	4,939
EBITDAX	**75,620**	**64,539**	**221,714**	**167,472**

EBITDAX 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.

Funds from Operations Reconciliation

	Three months ended		LTM	Year ended
	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000	Mar 31, 2013 US$'000	Dec 31, 2012 US$'000
Net profit after tax	29,611	23,798	79,752	58,846
Add/(less) non-cash items				
Depletion, Depreciation and amortisation expense	17,915	15,036	54,318	39,161
Amortisation of borrowing costs and discount /premium on financial instruments	777	815	3,344	2,927
Share based payment expense	1,374	1,102	4,545	4,398
Income tax expense	15,757	13,416	48,040	37,356
Net Foreign exchange loss/(gain)	44	14	(2,942)	(3,042)
Employee Benefit Provision	20	(26)	77	242
Funds from Operations	**65,498**	**54,155**	**187,134**	**139,888**

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.