Equities: Aurora Oil and Gas Limited

16 February 2011 | ASX Code: AUT | Energy

CommonwealthBank

Chuck Norris eats shale for breakfast

Investment view: Initiate with Buy and AUD3.45ps price target

- *We initiate coverage on Aurora with a Buy recommendation and price target of AUD3.45.* Aurora has interests in the liquids rich Sugarkane shale gas field development. We see material reserves upside from completion improvements, enhanced estimated ultimate recovery (EUR) and tighter well spacing. Aurora also offers material production and earnings over the next decade.

Sugarkane liquid-rich shale results in higher returns profile

- *The Sugarkane gas-condensate field is a new Eagle Ford Shale and Austin chalk development in southern Texas.* The field covers the wet gas-condensate and oil windows and is relatively over-pressured which results in greater levels of well productivity. AUT has interests in four of the Sugarkane Area of Mutual Interests (AMIs) covering 72,900 acres: Sugarloaf, Longhorn, Ipanema and Excelsior.
- *High liquids content improves returns.* While the relative energy differential for oil and gas is ~6:1, the value differential in the US is >20:1. Break-even pricing for liquids-rich shale is much lower with returns higher. Chesapeake estimates breakeven pricing of USD4-5/mcfe for dry gas versus USD50/bbl for wet-gas shales. Its Eagle Ford acreage is estimated to generate returns >50%.

Upside from maturity, drilling improvements and tighter spacing

- *Aurora anticipates the 2011 drilling program will convert the majority of the 3P reserves to 2P reserves by the end of 2011.* The first stage of upgrades is likely to be announced late-February with the initial reserves report based on six production wells versus the 15 currently producing. The company's 2P reserves currently only represent 15% of 3P reserves.
- *Completion improvements, EUR per well and tighter well spacing to materially increase 3P reserves.* Since taking over operatorship, Hilcorp has confirmed the development's commerciality and significantly improved the completion techniques. Industry peers estimate increases to EUR of >30% resulting from optimised production practices. There also remains potential for reserves growth through tighter well spacing.
- *Aurora recently acquired additional interests in four Sugarkane AMIs for USD120m; we value the acquisition at over 2 times what Aurora paid.* We believe that there will continue to be small value accretive transactions available for consolidation in the Eagle Ford given the highly capital intensive nature of shale developments. We would be supportive for Aurora to continue to grow through acquisitions in well understood acreage close to Sugarkane.

Catalysts and risks

- Key catalysts: (1) Reserves upgrades - (a) late-February update to result in 2P growth given increased maturity, and (b) late-2011 potential for material 3P growth from completion improvements, enhanced EUR and tighter well spacing; (2) Ongoing drilling updates – 60 wells proposed for completion in 2011; (3) Significant production/earnings growth; and (4) Further accretive acquisitions.
- Key risks: (1) Maturity of development – only 15 wells on production; (2) Availability and cost of services — regional work-load has the potential for rig and fraccing equipment to be unavailable; and (3) Environmental management.

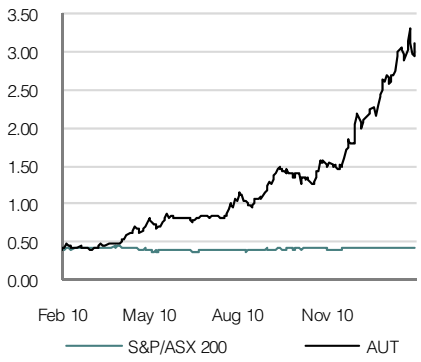
Buy

Price target	$3.45
Share price	$3.13
52-week range	$0.39 - $3.32
Forecast price return	10.2%
Forecast dividend return	0.0%
Forecast total return	10.2%
Market cap	$1263m

Forecasts and ratios

Year end Dec	08	09	10f	11f	12f
NPAT $m	-15	-3	-2	38	96
EPS c	-7.2	-1.5	-0.7	9.6	23.5
EPS growth %		79.9	53.7	1516.9	145.7
P/E x	-2.4	-18.5	-331.7	32.7	13.3
EV/EBITDA x	-2.8	-19.5	-462.8	15.5	6.0
DPS c	0.0	0.0	0.0	0.0	0.0
Yield %	0.0	0.0	0.0	0.0	0.0

Price relatives ($)



The S&P/ASX200 has been re-based to the stock's starting share price.

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Financials

Profit & Loss (US$m)	2009	2010f	2011f	2012f	2013f
Production (mmboe)	**0.0**	**0.0**	**1.4**	**3.5**	**5.5**
Sales Revenue	0	1	99	246	353
EBITDAX	**-2**	**-1**	**82**	**207**	**295**
Exploration & Impairment	0	0	0	0	0
EBITDA	**-3**	**-2**	**82**	**207**	**295**
Depn & Amortisation	0	0	23	56	85
EBIT	**-3**	**-2**	**59**	**151**	**210**
Net Interest	0	0	-1	-3	-2
Profit before tax	-3	-2	58	148	208
Tax expense	0	0	-20	-52	-73
NPAT	**-3**	**-2**	**38**	**96**	**135**
Preference Div Paid	0	0	0	0	0
Exceptional Items (post-tax)	0	0	0	0	0
NPAT Underlying	**-3**	**-2**	**38**	**96**	**135**
EPS Underying	**-1**	**-1**	**10**	**24**	**33**

Balance Sheet (US$m)	2009	2010f	2011f	2012f	2013f
Cash and equivalents	4	55	69	87	127
Receivables	1	1	41	67	97
Inventories	0	0	0	0	0
Other current assets	0	0	0	0	0
Current assets	**5**	**56**	**110**	**155**	**223**
Oil & Gas properties	19	144	226	286	360
Exploration assets	0	0	0	0	0
Other non-current assets	1	1	1	1	1
Non-current assets	**20**	**145**	**227**	**287**	**361**
Total Assets	**25**	**201**	**337**	**441**	**584**
Payables	0	0	6	15	22
Interesting bearing liabilities	0	0	0	0	0
Other current liabilities	0	0	0	0	0
Current Liabilities	**0**	**0**	**6**	**15**	**22**
Interesting bearing liabilities	0	0	50	50	50
Other non-current liabilities	0	0	0	0	0
Non-current Liabilities	**0**	**0**	**50**	**50**	**50**
Total Liabilities	**0**	**0**	**56**	**65**	**72**
Net Assets	**24**	**201**	**280**	**377**	**512**
Ordinary equity	24	201	280	377	512
Minority Interests	0	0	0	0	0
Total shareholder funds	**24**	**201**	**280**	**377**	**512**

Cash Flow (US$m)	2009	2010f	2011f	2012f	2013f
Profit after tax from operations	-3	-2	38	96	135
Depreciation & amortisation	0	0	23	56	85
Net change in working capital	0	-1	-33	-18	-22
Other	1	0	0	0	0
Net operating cash flows	**-2**	**-2**	**27**	**134**	**198**
Capital & Exploration	-2	-126	-104	-116	-159
Other	0	0	0	0	0
Investing cashflow	**-2**	**-126**	**-104**	**-116**	**-159**
Dividends paid	0	0	0	0	0
Equity raised	0	178	42	0	0
Net borrowings	0	0	50	0	0
Other	0	0	0	0	0
Financing cashflow	**0**	**178**	**92**	**0**	**0**
Increase/(decrease) in cash	**-5**	**50**	**15**	**18**	**39**

Financial Ratios	2009	2010f	2011f	2012f	2013f
Profitability ratios					
EBITDA margin	-523.8%	-121.4%	82.2%	84.0%	83.7%
EBIT margin	-604.6%	-144.9%	59.4%	61.2%	59.6%
Return on assets	-12.8%	-1.8%	22.0%	38.7%	41.0%
Return on equity	-12.9%	-1.7%	15.7%	29.3%	30.5%
ROIC	-9.7%	-0.9%	14.7%	28.9%	31.4%

Market Information	
Recommendation	Buy
Price Target (A$)	3.45
Last Price (A$)	3.13
Current A$/US$	1.00
Issued Capital (m)	403
Market Capitalisation (A$m)	1,263
Year end	December

Pricing	2009	2010f	2011f	2012f	2013f
Average shares (m)	203	291	395	409	409
EPS Underlying (USc)	-1	-1	10	24	33
PE Ratio	-170.1	-422.1	31.6	11.6	8.0
BVPS	0.1	0.7	0.7	0.9	1.3
P/B	2.0	4.4	4.1	2.9	2.1
DPS (USc)	0	0	0	0	0
Dividend Yield	0.0%	0.0%	0.0%	0.0%	0.0%

Valuation	A$m	$ps	Risk	Reserves	$/boe
Operations				**2P mmboe**	
Sugarloaf	371	0.91	100%	28	13.3
Longhorn	649	1.59	100%	44	14.7
Ipanema	146	0.36	100%	13	10.9
Excelsior	107	0.26	100%	7	14.5
Total Operations	**1,272**	**3.11**		85	14.9
Other Assets	4	0.01			
Net Debt	93	0.23			
Corporate	-44	-0.11			
Total Valuation	**1,325**	**3.24**		85	15.5

Production	2009	2010f	2011f	2012f	2013f
Sales Gas (bcf)	0.0	0.1	3.8	9.3	15.1
LPG (mmboe)	0.0	0.0	0.2	0.5	0.7
Oil/Condensate (mmbbl)	0.0	0.0	0.8	1.9	2.9
Total (mmboe)	0.0	0.0	1.4	3.5	5.5
Total (kboe/d)	0.0	0.1	3.9	9.6	15.0
Sugarloaf (mmboe)	0.0	0.0	0.3	0.7	1.4
Longhorn (mmboe)	0.0	0.0	0.8	2.1	2.8
Ipanema (mmboe)	0.0	0.0	0.2	0.6	1.0
Excelsior (mmboe)	0.0	0.0	0.1	0.2	0.3

Divisional EBIT (US$m)	2009	2010f	2011f	2012f	2013f
Sugarloaf	0	1	14	28	52
Longhorn	0	0	37	96	118
Ipanema	0	0	7	20	30
Excelsior	0	0	3	9	13
Other	-3	-3	-2	-2	-2
Total	**-3**	**-2**	**59**	**151**	**210**

Assumptions	2009	2010f	2011f	2012f	2013f
A$/US$	0.79	0.91	0.97	0.87	0.85
WTI Oil (US$/bbl)	61.8	78.8	99.6	100.8	94.2
Henry Hub Gas (US$/mmbtu)	3.9	4.6	5.6	5.7	5.3

Financial Ratios	2009	2010f	2011f	2012f	2013f
Balance sheet ratios					
Net Debt	-4	-55	-19	-37	-77
Gearing (ND/ND+E) (book)	-22%	-37%	-7%	-11%	-18%
Gearing (ND/ND+E) (market)	-9%	-5%	-2%	-4%	-8%
Interest cover	92.6	20.0	89.9	79.0	130.9

Source: Company data, CBA

Executive summary

We initiate coverage on Aurora with a Buy recommendation and price target of AUD3.45. Aurora has interests in the liquids-rich Sugarkane shale gas field development. We see material reserves upside from completion improvements, enhanced estimated ultimate recovery and tighter well spacing. The company also offers material production and earnings growth over the next decade.

Table 1: AUT – DCF net asset valuation

AUT Valuation	AUDm	AUDps	Risk	Production mmboe	AUD/boe
Sugarloaf	371	0.91	100%	28	13.3
Longhorn	649	1.59	100%	44	14.7
Ipanema	146	0.36	100%	13	10.9
Excelsior	107	0.26	100%	7	14.5
Total Operations	**1,272**	**3.11**		85	14.9
Other Assets	4	0.01			
Net Cash/(Debt)	93	0.23			
Corporate	-44	-0.11			
Total Valuation	**1,325**	**3.24**			
Price Target* - ps		**3.45**			

Source: Company data, CBA

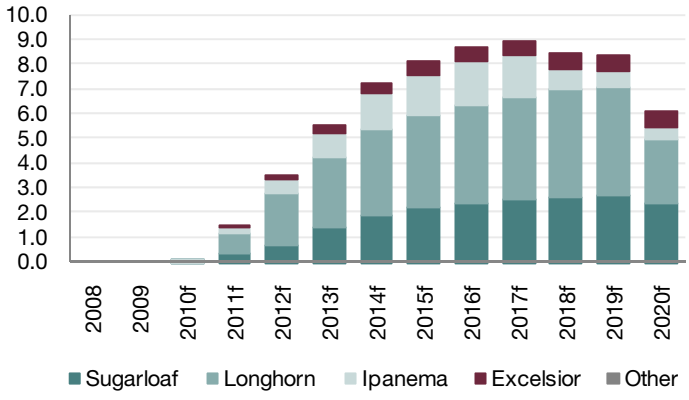
*Note: * Price target based on one-year forward valuation given growth profile of business*

Sugarkane liquid-rich shale development results in higher returns profile

The Eagle Ford shale is located in Southern Texas and benefits from spanning the entire window of hydrocarbon maturation. The Sugarkane gas and condensate field is a new Eagle Ford Shale and Austin chalk development which covers >200,000 acres across the wet gas-condensate and oil windows. On top of the high liquids content, the Sugarkane area is relatively over-pressured compared to the rest of the Eagle Ford trend which results in greater levels of well productivity.

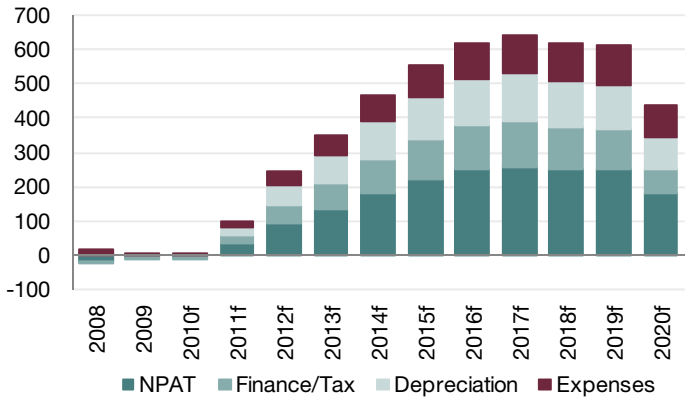
- *Aurora has interests in four of the Sugarkane AMIs*: Sugarloaf, Longhorn, Ipanema and the recently acquired Excelsior AMI. These AMIs cover the northern portion of the Sugarkane field over an area of 72,900 acres.
- *The JV across the four AMIs is proposing to undertake 60 new wells during 2011* which will bring total wells to 80 across the four AMIs by year end. The company considers ongoing drilling over the field as a low-risk development phase. Two additional drilling rigs recently commenced operations bringing the rig count to four, with each rig anticipated to complete one horizontal well each month. Aurora estimates that production will reach 2.8kboe/d by June 2011 and 5.0kboe/d by December 2011.

Figure 1: Production growth outlook (mmboe)



Source: CBA

Figure 2: Earnings growth outlook (USDm)



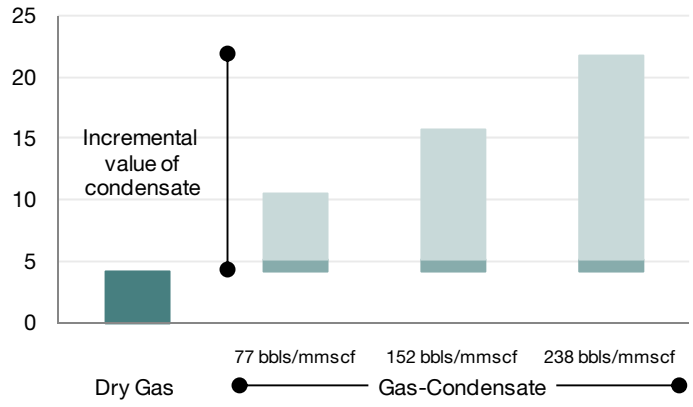
Source: CBA

Benefits of higher liquids content Eagle Ford shale – lower break-even and higher returns

The further North-West portions of the Sugarkane field have increased levels of liquids content. Wells have the potential to produce at rates of over 400 bbls/mmscf. While the relative energy differential for oil and gas is approximately 6:1, the value differential between Henry Hub gas and WTI oil prices has decoupled over recent years and increased to over 20:1. Production curves modelled in reserves modelling undertaken by NSAI generate 2.6-5.4 times the revenue per mscfe of gas produced due to higher liquids content of the field (see Figure 3).

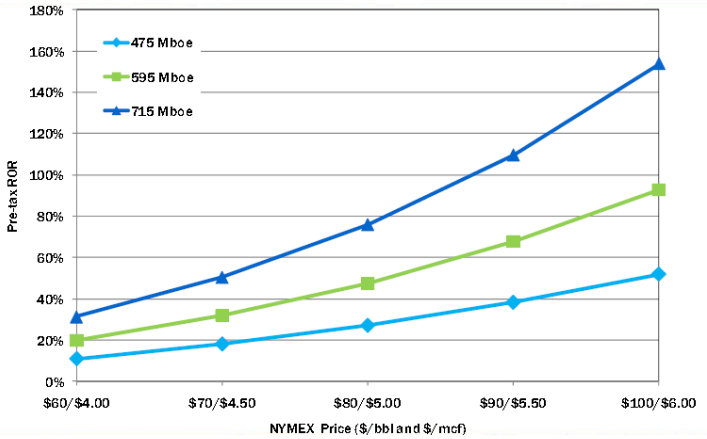
Given this, the relative break-even price for liquids-rich shale developments is much lower than dry gas developments. Chesapeake Energy – the second largest producer of natural gas in the United States – estimates its shale portfolio's breakeven pricing is approximately USD4-5/mcfe for dry gas shale compared to USD50/bbl for wet-gas/oil shales. As a result, Chesapeake's *Eagle Ford acreage is estimated to generate returns of greater the 50% on the basis of USD80/bbl oil and USD5.00/mscf gas prices* (see Figure 4).

Figure 3: Incremental value from liquids (USD/mscfe)



Source: Company data

Figure 4: Chesapeake – Eagle Ford shale returns



Source: Chesapeake

Upside from increased maturity, drilling improvements and tighter spacing

There are significant areas of upside for Aurora and the Sugarkane development, including:

- *Upside from improved drilling performance and efficiency.* Given the repetitive, logistical nature of shale gas developments there is material upside potential that can result from improved drilling performance and efficiency. Economics of the development will be highly leveraged to the capital costs per well, gas production flow-rates, ultimate recoverability and liquids content of each of the wells. Focusing on optimisation of drilling efficiency, improved cycle times and optimised completions have the potential to unlock material long-term value. Aurora has already experienced a continued improvement in performance since farming-out operations to Hilcorp Energy.

- *Upside from 2P reserves conversion resulting from ongoing drilling and increased certainty.* There is material upside to the company's current proven and probable (2P) reserves which only represent 15% of 3P reserves. The current NSAI reserves report was developed on the basis of six wells on production. This has increased significantly with 21 wells currently on production or being drilled and completed. We see initial upgrades as highly likely at the upcoming February reserves update. Aurora anticipates the accelerated drilling program over the coming 12 months (a further 60 wells are proposed for 2011) will convert the majority of the 3P reserves to 2P reserves by the end of 2011.

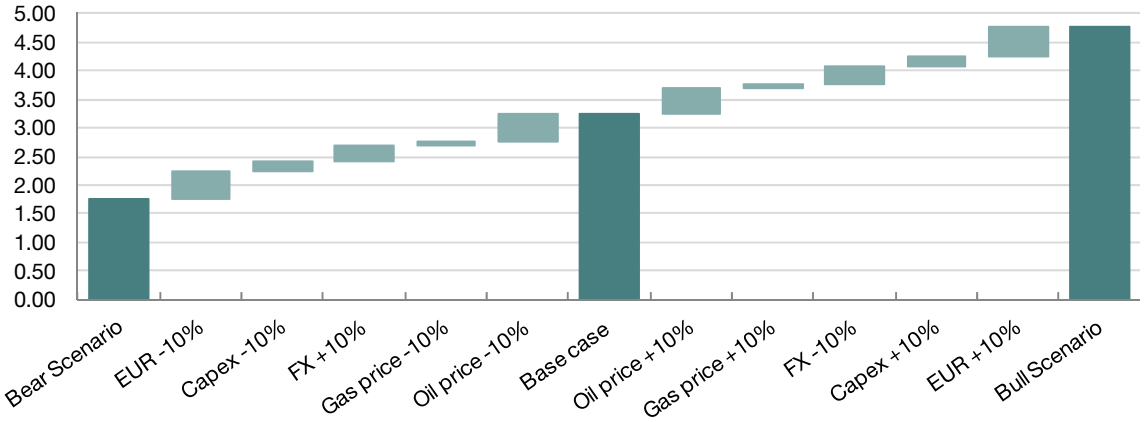
- *Upside from 3P reserves growth from completion practice improvements.* Well outperformance and completion improvements have the potential to materially increase the company's 3P reserves position. Hilcorp has significantly improved the completion techniques since farming-in. The JV is currently performing restricted choke setting production practices. While this reduces initial production rates, maintaining high rate production practices has risks including embedment, fines migration and proppant deformation. Restricted choke practices therefore have the potential to maintain more moderate levels of decline. Petrohawk, which is undertaking similar production practices, estimates first year decline reduction from 80-85% to 45-50%. It estimates increases to EUR of more than 30% resulting from these optimised production practices.

- *Upside from 3P reserves growth from tighter well spacing.* The initial NSAI reserves report was developed on the basis of 80-acre well spacing. There remains potential for significant recoverable reserves growth through tighter well spacing given overall recovery remains low across the field on current NSAI development modelling.

- *Upside from near-field accretive acquisitions.* Aurora recently increased its stake in the Sugarkane field development by acquiring additional AMI interests. This was a smart low-risk acquisition in our view given knowledge of the acreage under existing operator Hilcorp. Importantly the deal was materially NPV accretive; we value the acquisition at over 2 times what Aurora paid. There should continue to be small value-accretive transactions available for consolidation in the Eagle Ford. Shale gas developments are highly capital intensive and require ongoing time sensitive drilling to retain acreage. We would be highly supportive for Aurora to continue to grow the business beyond its existing interests in well understood acreage in close proximity to existing positions.

The following chart highlights the upside (and downside) potential for various valuation scenarios. The chart highlights that greatest valuation leverage relates to oil price movements and EUR per well. This highlights the importance of completion technique improvements and ultimate reserves recoverability to the valuation of the company.

Figure 5: AUT – Valuation: Bull and Bear scenarios (AUDps)



Source: Company data, CBA

Catalysts

Key catalysts largely relate to increased maturity and commercialisation of the reserves base at Sugarkane:

- *Reserves upgrades*:
  - *Late February reserves update* should be certain to result in 2P reserves growth given increased number of production wells since initial report, with some potential for moderate levels of 3P reserves upside.
  - *Late 2011 reserves update* is more likely to be the timing of potential material 3P reserves growth through completion improvements, enhanced EUR per well and tighter well spacing.

- *Ongoing drilling and production updates* – 60 wells proposed for completion in 2011 which will increase the understanding of the Sugarkane development.
- *Significant production and earnings growth* – the company estimates that production will reach 2.8kboe/d by June 2011 and 5.0kboe/d by December 2011.
- *Further accretive acquisitions* –we believe that there will continue to be small value-accretive transactions available for consolidation in the Eagle Ford. We would be highly supportive for Aurora to continue to grow the business beyond its existing interests in well understood acreage in close proximity to existing positions.

Risks

Key risks include:

- *Early stages of development* — the Sugarkane field is at a relatively early stage of development and there are a significant number of unknowns regarding the development. The project should be de-risked as the field is appraised further through drilling and production from more wells.
- *Availability and cost of services* — given the level of work being undertaken in the region there is the potential that drilling and especially fracture stimulation equipment will be unavailable when required. Equipment constraints may also result in an increase to costs of oil field services.
- *Environmental management* — according to JV partners this is less of an issue in Southern Texas, however environmental concerns regarding hydraulic fracture stimulation, produced water, contamination of aquifers and other concerns which have the potential to influence the development schedule of the project.

Core Projects and exploration

Aurora has interests in four AMIs over the Sugarkane shale gas field development in the Eagle Ford, Southern Texas. The field covers the wet gas-condensate and oil windows. The higher liquids content significantly improves returns given current disparity between US gas and oil prices. The field is currently undergoing a significant development phase, with 60 wells planned for 2011 increasing total production wells to 80 by year-end.

Table 2: AUT – key project status

Project	Interest	Gross acreage	Net acreage	3P reserves (net) Gas (bcf)	3P reserves (net) Liquids (mmbbl)	Gas liquids ratio (bbls/mmscf)
Sugarloaf AMI	15.7%	23,500	3,690	77.1	12.91	168
Longhorn AMI	31.9%	26,900	8,581	68.9	28.46	413
Ipanema AMI	36.4%	4,600	1,674	47.4	4.52	95
Excelsior AMI	9.1%	17,900	1,629	8.4	5.15	610
Total		72,900	15,574	201.7	51.04	253

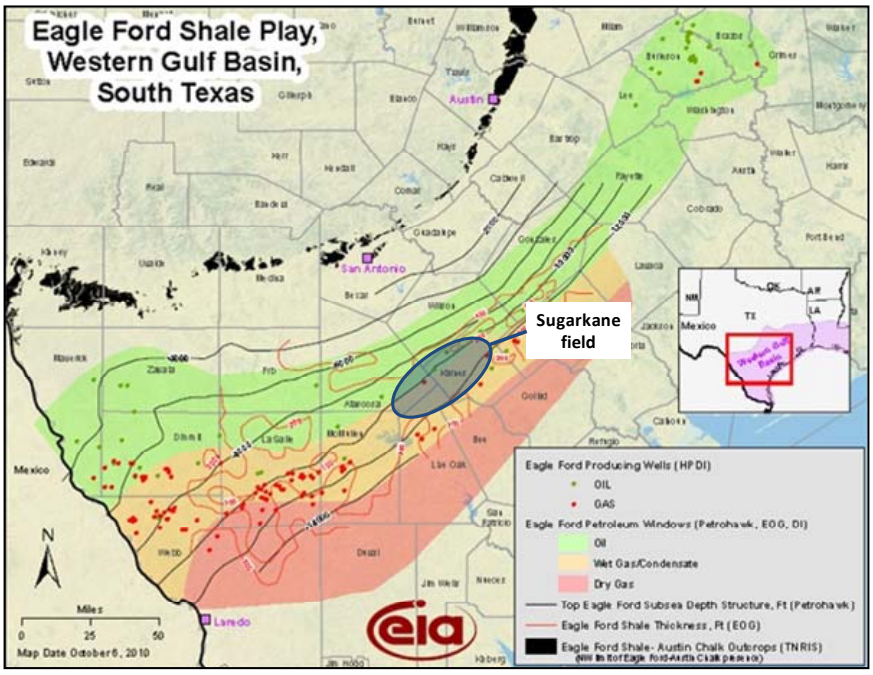
Source: Company data, CBA

Eagle Ford shale – Sugarkane gas and condensate field

The Eagle Ford shale is located in Southern Texas and benefits from spanning the entire window of hydrocarbon maturation. This is highlighted in the following chart, which shows the Eagle Ford's three hydrocarbon windows which include oil, wet gas-condensate and dry gas trends. As the formation gets deeper the further south it moves towards the Gulf of Mexico, the lower the liquids content. Given the high liquids content across the trend there has been increasing focus by the major US shale players looking to refocus their portfolios away from dry gas shales. Industry reports highlight over 100 rigs operating across the trend with significant ramp-up activities planned for the coming year.

The Sugarkane gas and condensate field is a new Eagle Ford Shale and Austin chalk development which covers in excess of 200,000 acres across southern Texas. The field covers the wet gas-condensate and oil windows.

Figure 6: Eagle Ford Shale (South Texas) and location of Sugarkane



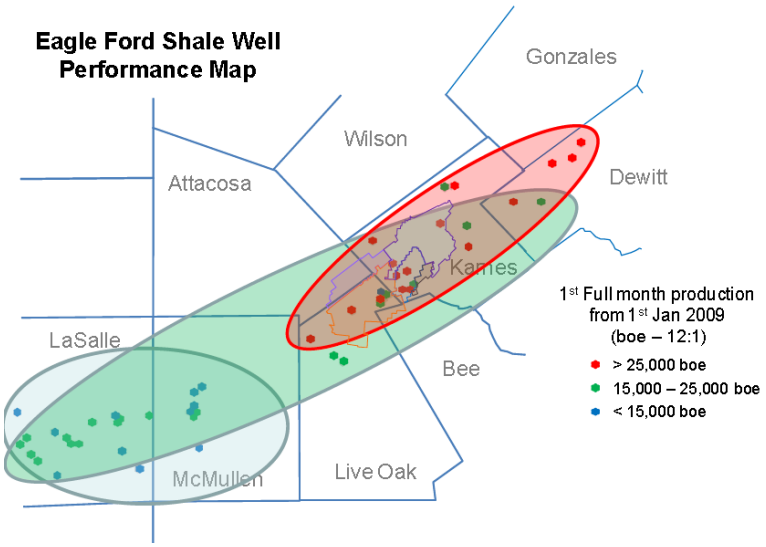
Source: EIA, CBA

Development – Aurora exposed to four of five Sugarkane AMIs

The field is broken into five distinct AMIs. Aurora has an interest in four of these AMIs; including Sugarloaf, Longhorn, Ipanema and the recently acquired Excelsior AMI (see Figure 8). These AMIs represent the Northern portion of the Sugarkane field and cover an area of 72,900 acres. Aurora first participated in the Sugarloaf #1 discovery in 2005.

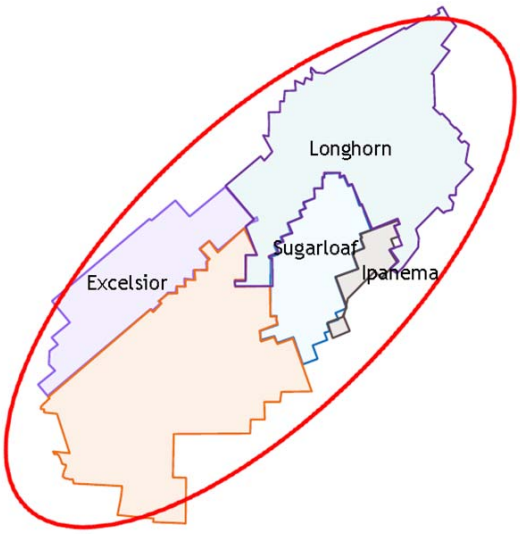
On top of the high liquids content, the Sugarkane field (highlighted in red in Figure 7) is relatively over-pressured compared to the rest of the Eagle Ford trend which results in greater levels of well productivity.

Figure 7: Eagle Ford Shale performance map



Source: Company data

Figure 8: Sugarkane field AMI breakdown



Source: Company data

Joint Venture participants – Hilcorp operated

Aurora is the only Australian-listed participant in three of the four AMIs that the company participates in over the Sugarkane field. AWE and Eureka Oil & Gas participate in the Sugarloaf AMI with 10% and 6.25% interests, respectively.

Hilcorp Energy is the operator of each of the four AMIs. Hilcorp is one of the largest privately owned E&P companies in the United States. Aurora farmed-down its interests in the company's three original AMIs to Hilcorp in September 2009, with the company taking over operatorship early 2010. Hilcorp carried the joint-venture for a 10-well program which confirmed the commerciality of the development and significantly improved the completion techniques. The first six wells of the program resulted in maiden reserves being reported over the field in August 2010.

The 10-well farm-in program included:

- fracture stimulation of three existing wells at Sugarloaf,
- drilling and completion of three new wells at Sugarloaf,
- three new wells at Longhorn, and
- one new well at Ipanema.

Hilcorp has subsequently completed its farm-in commitments. The farm-in agreements enabled Hilcorp to recover upfront capital expenditure from initial production from the farm-in wells. Aurora realised first revenues from both the original farm-in and post farm-in wells in the December quarter.

High liquids content across the four AMIs

Sugarloaf and Longhorn are the largest AMIs in Aurora's portfolio with similar gross acreage positions. The company's net acreage position consists of 15,600 acres; Aurora's working interest in these AMIs is outlined in Table 3. Given Aurora's high working interest in the Longhorn AMI it represents over half of the company's net acreage position across the Sugarkane field (see Figure 9).

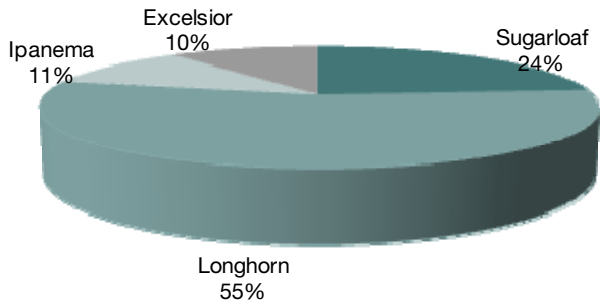
As is consistent with the Eagle Ford trend, the further North-West portions of the Sugarkane field have increased levels of liquids content. The Longhorn and Excelsior AMIs have potential to produce at rates of over 400 bbls/mmscf and also enter the oil sequence of the Eagle Ford shales. Figure 10 highlights the implied gas liquids ratio for each of Aurora's AMIs based on the current 3P reserves.

Table 3: AUT – Sugarkane AMI's acreage and liquids content

Project	Interest	Gross acreage	Net acreage	3P reserves (net)		Gas liquids ratio (bbls/mmscf)
				Gas (bcf)	Liquids (mmbbl)	
Sugarloaf AMI	15.7%	23,500	3,690	77.1	12.91	168
Longhorn AMI	31.9%	26,900	8,581	68.9	28.46	413
Ipanema AMI	36.4%	4,600	1,674	47.4	4.52	95
Excelsior AMI	9.1%	17,900	1,629	8.4	5.15	610
Total		72,900	15,574	201.7	51.04	253

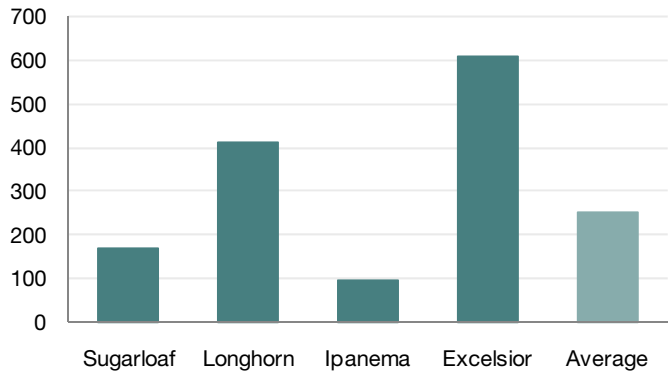
Source: Company data, CBA

Figure 9: AUT – net acreage breakdown



Source: Company data, CBA

Figure 10: Gas-liquids ratio (bbl/mmscf) – based on 3P reserves



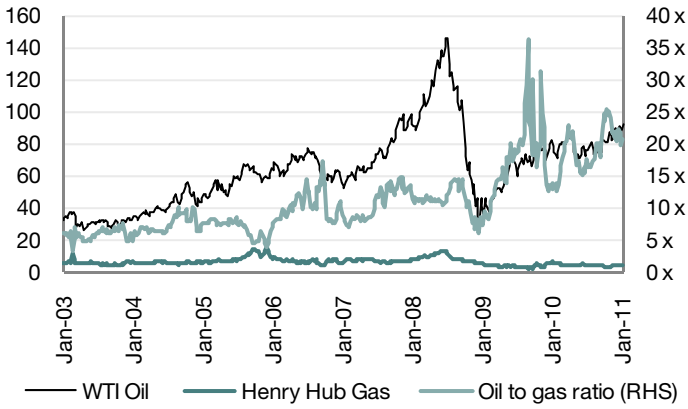
Source: Company data, CBA

Oil and gas price disparity improves revenue generation in high-liquids areas

While the relative energy differential for oil and gas is approximately 6:1, the value differential between Henry Hub gas and WTI oil prices has decoupled over recent years and increased to over the 20:1 ratio currently (see Figure 11).

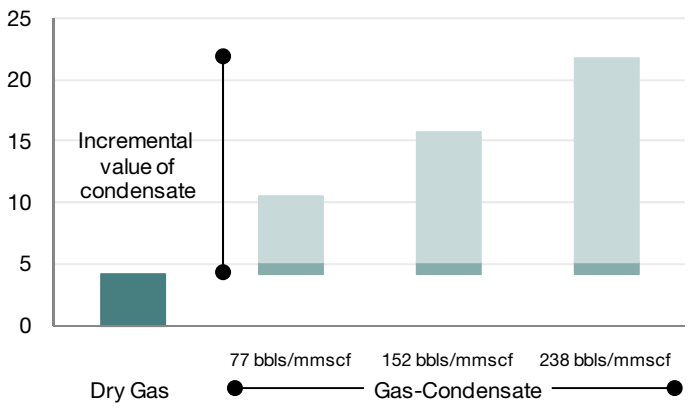
Figure 12 highlights the implications on incremental realised value from the liquids production from Aurora's original three AMIs (Sugarloaf, Longhorn and Ipanema). On top of the oil and gas price disparity, gas produced at Sugarkane has a high calorific content and receives a 25% premium to Henry Hub gas prices. Production curves modelled in reserves modelling undertaken by NSAI generate 2.6-5.4 times the revenue per mscfe of gas produced due to higher liquids content of the field.

Figure 11: Gas-liquids price disparity (USD)



Source: Bloomberg, CBA

Figure 12: Incremental value from liquids (USD/mscfe)



Source: Company data

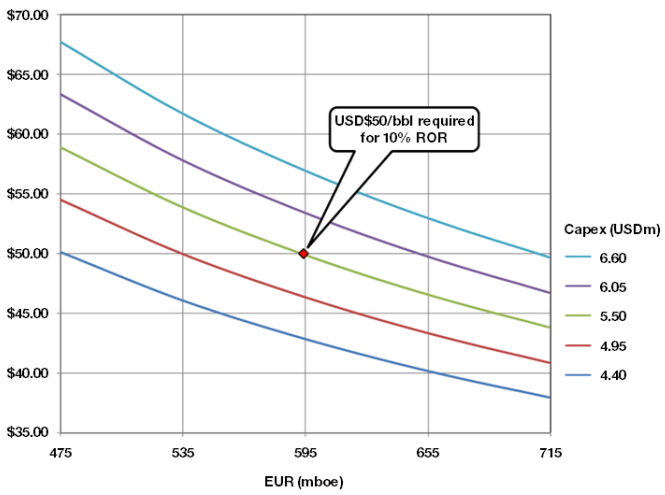
Higher liquids content results in lower break-even price...

As a result of the higher liquids content in the gas, the relative break-even price for liquids-rich shale developments is much lower than dry gas developments. The following two charts are taken from recent Chesapeake Energy presentations. Chesapeake is the second largest producer of natural gas in the United States and has the number one or two acreage position in all five major natural gas shale plays.

Chesapeake estimates the break-even scenario for Haynesville shale (largely dry gas), based on returns of 10%, can be accomplished at USD4.25/mcfe (see Figure 14). This only represents a small discount to where Henry Hub gas prices are currently trading, therefore limiting the economics of the development. In some of Chesapeake's other dry gas acreage this breakeven gas price increases to above USD5.00/mscfe, making the developments sub-economic at current prices.

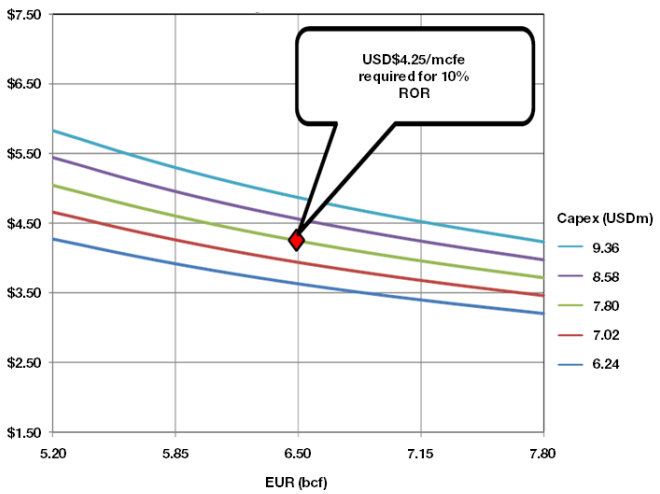
This compares to Chesapeake's Eagle Ford acreage in the oil and wet-gas window which requires only a USD50/bbl oil price to break-even (as highlighted in Figure 13). This represents a significant discount to where oil prices are currently trading. Chesapeake's acreage is not fully comparable to Aurora's, however this highlights the benefits of higher liquids content in shale developments.

Figure 13: Chesapeake – Eagle Ford shale breakeven



Source: Chesapeake

Figure 14: Chesapeake – Haynesville shale breakeven



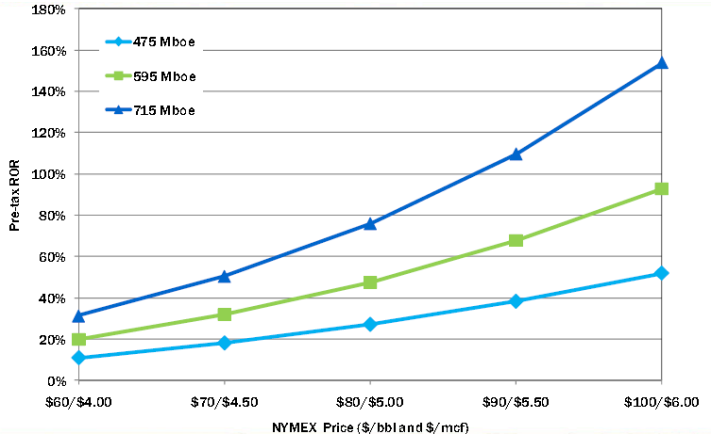
Source: Chesapeake

... liquids-rich shales can generate returns of >50%

The following two charts highlight industry returns from the Eagle Ford shale. Chesapeake's acreage can generate returns of greater than 50% on the basis of USD80/bbl oil and USD5.00/mscf gas prices (see Figure 15). Figure 16 highlights the relative returns from Petrohawk Energy's shale gas portfolio. The company's Eagle Ford oil and wet-gas acreage generates materially greater returns than the company's Haynesville and Fayetteville dry gas shales.

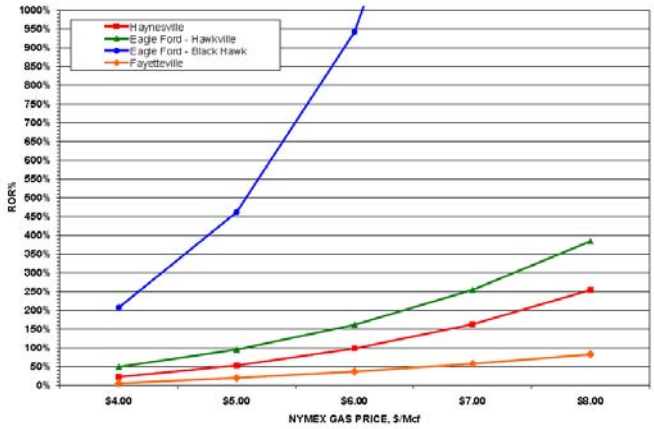
The US shale industry is therefore becoming increasingly focussed on liquids rich shales. Chesapeake is materially shifting capital from dry gas to liquids-rich shale plays –increasing liquids focused capex to 70% in 2012 from 10% in 2009.

Figure 15: Chesapeake – Eagle Ford shale returns



Source: Chesapeake

Figure 16: Petrohawk – Comparative returns between dry and wet gas acreage



Source: Petrohawk

Upside – Improved drilling performance and efficiency

There is material potential for improved performance given the repetitive, logistical nature of shale developments. Economics of the development will be highly leveraged to the capital costs per well, gas production flow rates, ultimate recoverability and liquids content of each of the wells. As highlighted in Table 4, focusing on optimisation of drilling efficiency, improved cycle times and optimised completions have the potential to unlock material long-term value. Aurora has already experienced a continued improvement under operator Hilcorp.

Table 4: Potential for improved performance

Drilling days	Experience and proper technology application decrease drilling days in lateral; play specific bit and motor
Rig efficiency	Reduced cycle time enables more wells per rig per year
Target zones	Geologic targets refined and lateral placement high-graded
Lateral length	Optimization of lateral length; strong EUR to completed lateral length relationship; focus on lowering $/ft
Drilling and Completion (D&C) costs	Gains made through experience and efficiency
Completion design	"Fine tuning" of completion designs for rock properties and sub-field areas improves EUR; focus on achieving maximum recovery and PV
Initial production rate	Improving with optimized completions and targeting within zone
EUR	Upward reserve "creep" with more production history as performance enhancements are achieved
Production methods	Optimization in production methods improves average well EUR and well performance prediction
Recovery factors & GIP	Recovery factors increase and GIP estimates rise with improved completion design and production methods
Logistics	Development strategies are streamlined to boost economics and cycle time; leverage work volume for favored pricing and "turn around time"
Infrastructure	Economics improve as infrastructure expands and marketing options increase

Source: Chesapeake

Upside – Conversion of majority of 3P reserves to 2P over 2011

There is material upside to the company's current proven and probable (2P) reserves which currently only represent 15% of 3P reserves (as highlighted in Table 5 and Figure 17). The current NSAI reserves report was developed on the basis of six wells on production. This has increased significantly with 21 wells currently on production or being drilled currently. Aurora anticipates the accelerated drilling program over the coming 12 months (a further 60 wells are proposed for 2011) will convert the majority of the 3P reserves to 2P reserves by the end of 2011.

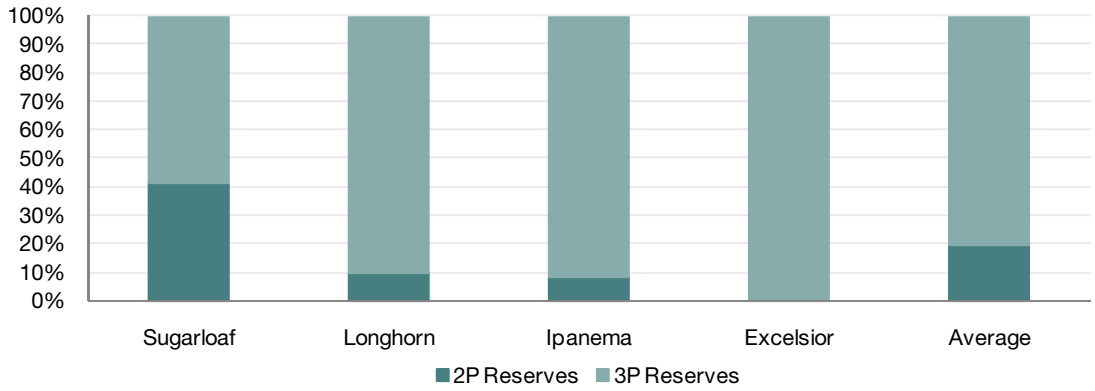
Table 5: AUT - Reserves position*

	Proved and probable (2P)			Proved, probable and possible (3P)			2P to 3P ratio
Area	Oil/Cond (mmbbl)	Sales Gas (bcf)	Total (mmboe)	Oil/Cond (mmbbl)	Sales Gas (bcf)	Total (mmboe)	Total (%)
Sugarloaf	4.26	28.9	9.1	12.91	77.1	25.8	35%
Longhorn	2.02	7.1	3.2	28.46	68.9	39.9	8%
Ipanema	0.14	1.8	0.4	4.52	47.4	12.4	4%
Excelsior	0.00	0.0	0.0	5.15	8.4	6.6	0%
Total	**6.4**	**37.7**	**12.7**	**51.0**	**201.7**	**84.7**	**15%**

Source: Company data

*Note: * Net working interest and net of royalties*

Figure 17: AUT – 2P to 3P reserves ratio



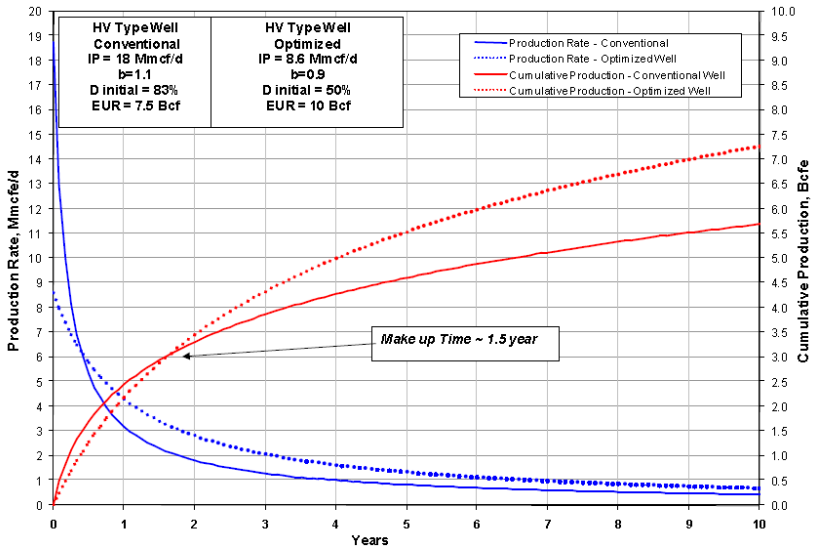
Source: Company data, CBA

Upside – 3P reserves growth from completion practice improvement and tighter well spacing

Well outperformance and completion improvements have the potential to materially increase the 3P reserves position. Aurora is currently performing restricted choke setting production practices. While this reduces initial production rates, maintaining unrestricted production practices has risks including embedment, fines migration and proppant deformation. Restricted choke practices have the potential to maintain more moderate levels of decline, with Petrohawk who is undertaking similar production practices estimating a reduction to the first-year decline from 80-85% to 45-50% (see Figure 18). It estimates increases to EUR of more than 30% resulting from these optimised production practices. Current well outperformance and completion improvements therefore have the potential to materially increase Aurora's 3P reserves position from initial NSAI estimates.

Tighter well spacing offers resource growth potential as well. The initial NSAI reserves report was developed on the basis of 80-acre well spacing. There remains potential for significant recoverable reserves growth through tighter well spacing given overall recovery remains low across the field on current NSAI development modelling.

Figure 18: Well type comparisons – impact of restricted choke settings



Source: Petrohawk

Upside – Near-field accretive acquisitions

Aurora recently increased its stake in the Sugarkane field development by acquiring additional interests in four Sugarkane AMIs for USD120m with an effective date of 1 December 2010. The acquisition provides Aurora with exposure to the Excelsior AMI and increases the company's interest in the three originally held Sugarkane AMIs. This roughly increases Aurora's net acreage position and 3P reserves by 50% to 15,600 acres and 84 mmboe, respectively. This was a smart low-risk acquisition in our view given the knowledge of the acreage, well understood growth potential and management by the existing operator Hilcorp.

Of core importance was that while the acquisition may be viewed as expensive on a per acre basis - a methodology that we do not agree with given it ignores many significant factors - the deal was materially NPV accretive. Based on our modelling the acquisition could be valued at approximately AUD407m, which represents over 2 times what Aurora paid (see Table 6).

We believe that there will continue to be small value-accretive transactions available for consolidation in the Eagle Ford. Shale gas developments are highly capital intensive and require ongoing time-sensitive drilling just to retain acreage. We would be highly supportive for Aurora to continue to grow the business beyond its existing interests in well understood acreage in close proximity to existing positions.

Table 6: AUT – recent acquisition valuation uplift

	Pre acquisition interests		Post acquisition interest		Acquired interest*	
	WI %	NPV (AUDm)	WI %	NPV (AUDm)	WI %	NPV (AUDm)
Sugarloaf	10.0%	236	15.7%	371	5.7%	135
Longhorn	25.0%	509	31.9%	649	6.9%	140
Ipanema	30.0%	120	36.4%	146	6.4%	26
Excelsior	0.0%	0	9.1%	107	9.1%	107
Total		**865**		**1272**		**407**
Acquisition (AUDm)						122
Uplift						**235%**

Source: Company data, CBA

*Note: * Valuation uplift ignores that the vendor retains the rights to the existing 21 production wells*

Issues

- *Early stages of development* — The Sugarkane field is at a relatively early stage of development and there are a significant number of unknowns regarding the development. The project should be de-risked as the field is appraised further through drilling and production from more wells.
- *Availability and cost of services* — Given the level of work being undertaken in the region there is the potential that drilling and especially fracture stimulation equipment will be unavailable when required. Equipment constraints may also result in an increase to costs of oil field services.
- *Environmental management* — According to JV partners this is less of an issue in Southern Texas, however general industry environmental concerns regarding hydraulic fracture stimulation, produced water, contamination of aquifers and other concerns have the potential to influence the development schedule of the project.

Production and forward plan

As at year-end the joint-venture was producing from 15 wells with another 6 wells in the process of drilling and completion (see Table 7). At year end the Sugarkane field was producing rates of 24.3mmscf/d gas and 5.8kbopd condensate. The company estimates that production will reach 2.8kboe/d by June 2011 and 5.0kboe/d by December 2011.

It is proposed that 60 new wells will be undertaken across the four AMIs in 2011, bringing the total wells to 80 across the four AMIs by year end. The company considers ongoing drilling over the field as a low-risk development phase. Two additional drilling rigs recently commenced operations bringing the rig count to four. The company anticipates each rig will complete one horizontal well each month.

Table 7: Sugarkane field – Well status (as at December 2010)

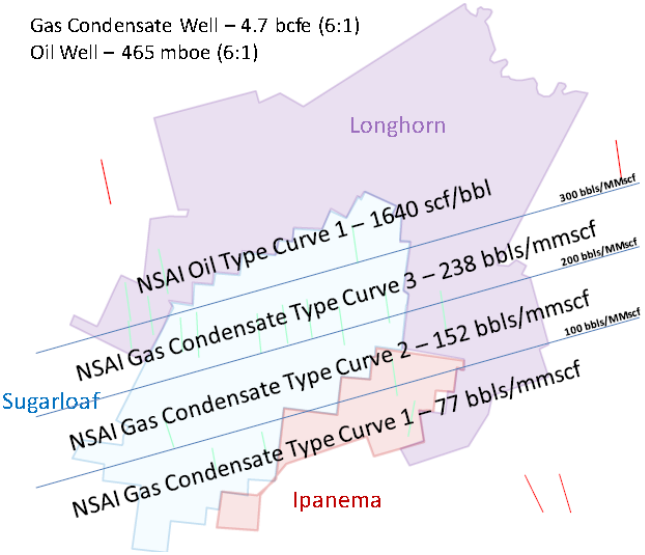
AMI	Sugarloaf	Longhorn	Ipanema	Excelsior	Total
Farm-out wells					
Producing	5	3	1	3	**12**
Post Farm-out					
Producing	3	0	0	0	**3**
Fracture stimulated	1	0	0	0	**1**
Fracturing	1	0	0	0	**1**
Drilled and cased	0	1	1	0	**2**
Drilling	1	1	0	0	**2**
Total	**11**	**5**	**2**	**3**	**21**

Source: Company data

Modelling

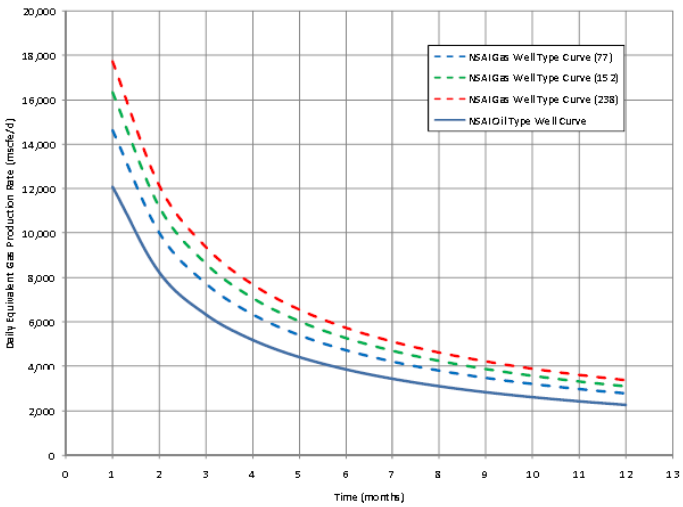
In undertaking our modelling we have sourced a number of our assumptions from the NSAI modelling undertaken for Aurora's current reserves report. NSAI model the full field development of 883 wells up to 2018 over the four AMIs. Figure 19 and Figure 20 show examples of the four production curves that were utilised in NSAI's modelling. Three gas curves were modelled with increasing liquids content the further north over the Sugarkane field, with one oil curve modelled over the northern portions of the field.

Figure 19: NSAI Type Curves – gas-liquids mix



Source: Company data

Figure 20: NSAI type curves – mscfe/d (12:1 conversion)



Source: Company data

Table 8 outlines our modelling assumptions. Figure 21 and Figure 22 outline our production and cash flow forecasts.

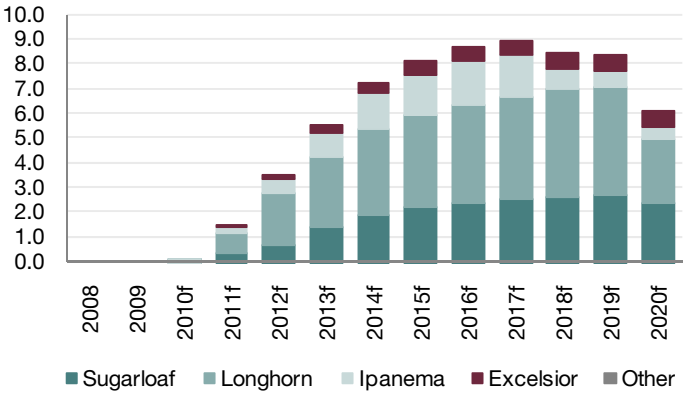
Table 8: Sugarkane field* – Modelling assumptions

Recoverable gas 3P reserves	**202bcf**
Recoverable oil/condensate 3P reserves	**51mmb**
Development cost (USDm per well)	7.0-8.0
Development cost (USDm over life of field, net)	1,434
Production wells	883
Est. Ultimate Recovery per well (bcfe)	3.2-4.7
First production post farm-out	4Q10
Production cost - well (USD/well/annum)	0.144
Production cost - gas transport (USD/mcf)	0.50
Production cost - liquids transport (USD/bbl)	1.50
Landowner Royalty Rate	25.0%
Severance Tax - Gas	7.5%
Severance Tax - Oil	4.6%
State Tax	2.0%

Source: Company data, CBA

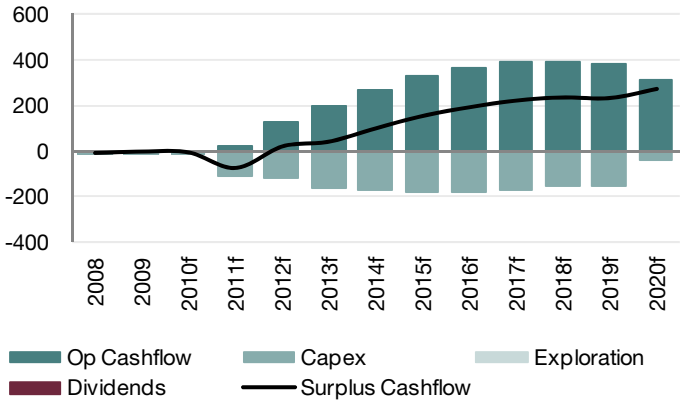
*Note: * Only reflects Aurora's exposure to four of the five AMIs over the Sugarkane field (ie excludes the Sugarkane AMI)*

Figure 21: Sugarkane field – production (mmboe, net)



Source: Company data, CBA

Figure 22: Sugarkane field – net cash flow (USDm)



Source: Company data, CBA

Financials and valuation

Aurora is currently undergoing a material development phase over its interests in the Sugarkane development. As a result the company is currently entering a material production and earnings growth period likely to continue over the decade as it continues to commercialise the Sugarkane resource.

Production and reserves

Production

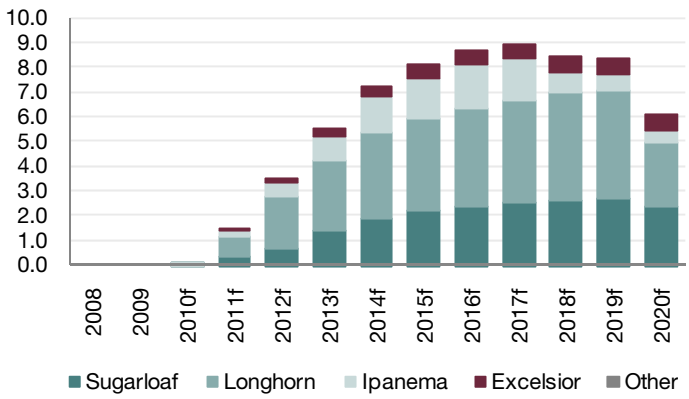
We forecast Aurora's total production to grow moderately but consistently as the Sugarkane JV develops the field. We forecast production to grow at 1.3mmboe per annum on average until production peaks in 2017 (see Figure 23). There is potential for production to grow beyond 2017 – our modelling assumptions are similar to the NSAI reserves modelling assumptions with 885 wells drilled over the field. Tighter well spacing has the potential to extend drilling beyond 2017. The Longhorn AMI is the most significant contributor to the production outlook, representing almost 50% of our forecast production for the company. As highlighted in Figure 24, liquids represent over 60% of our production forecast for the company.

Table 9: AUT - production forecast and breakdown

Production forecast	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Gas (bcf)	0.0	0.0	0.1	3.8	9.3	15.1	20.3	22.8	24.5	24.9	22.1	21.3	16.0
LPG (mmboe)	0.0	0.0	0.0	0.3	0.6	1.0	1.3	1.5	1.6	1.6	1.5	1.5	1.1
Oil/Condensate (mmbbl)	0.0	0.0	0.0	1.0	2.5	3.8	5.0	5.5	5.9	6.1	6.0	6.0	4.3
Total (mmboe)	**0.0**	**0.0**	**0.0**	**1.4**	**3.5**	**5.5**	**7.2**	**8.1**	**8.7**	**8.9**	**8.4**	**8.3**	**6.1**
Total (kboe/d)	0.0	0.0	0.1	3.9	9.6	15.0	19.8	22.2	23.8	24.5	23.1	22.8	16.7
Forecasts by Field													
Sugarloaf													
Gas (bcf)	0.0	0.0	0.0	0.8	1.7	3.3	4.6	5.2	5.7	6.0	6.3	6.5	5.7
LPG (mmboe)	0.0	0.0	0.0	0.1	0.1	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Oil/Condensate (mmbbl)	0.0	0.0	0.0	0.1	0.3	0.6	0.8	0.9	0.9	1.0	1.1	1.1	1.0
Total (mmboe)	0.0	0.0	0.0	0.3	0.7	1.4	1.9	2.2	2.3	2.5	2.6	2.7	2.4
Longhorn													
Gas (bcf)	0.0	0.0	0.0	1.3	3.1	4.3	5.2	5.7	6.1	6.4	6.6	6.7	3.9
LPG (mmboe)	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.3
Oil/Condensate (mmbbl)	0.0	0.0	0.0	0.5	1.3	1.8	2.2	2.4	2.5	2.6	2.7	2.8	1.6
Total (mmboe)	0.0	0.0	0.0	0.8	2.1	2.8	3.4	3.7	4.0	4.2	4.3	4.4	2.5
Ipanema													
Gas (bcf)	0.0	0.0	0.0	0.7	2.0	3.4	4.9	5.5	5.9	5.5	2.9	2.0	1.6
LPG (mmboe)	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Oil/Condensate (mmbbl)	0.0	0.0	0.0	0.1	0.2	0.3	0.5	0.5	0.6	0.5	0.3	0.2	0.2
Total (mmboe)	0.0	0.0	0.0	0.2	0.6	1.0	1.5	1.7	1.8	1.7	0.9	0.6	0.5
Excelsior													
Gas (bcf)	0.0	0.0	0.0	0.1	0.2	0.3	0.5	0.6	0.7	0.7	0.7	0.8	0.8
LPG (mmboe)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Oil/Condensate (mmbbl)	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5
Total (mmboe)	0.0	0.0	0.0	0.1	0.2	0.3	0.5	0.5	0.6	0.6	0.6	0.7	0.7

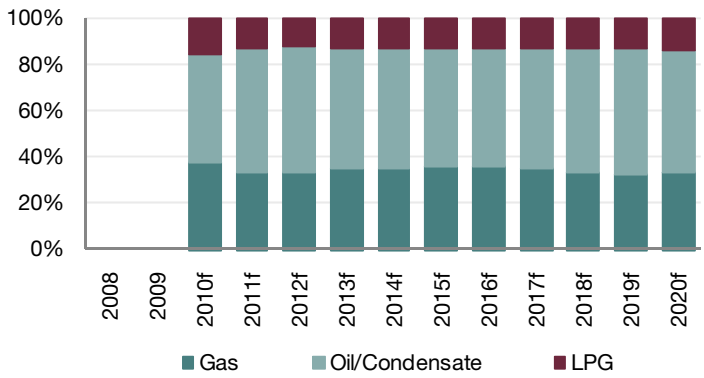
Source: Company data, CBA

Figure 23: AUT – production outlook (mmboe)



Source: Company data, CBA

Figure 24: AUT – production mix



Source: Company data, CBA

Reserves

Aurora has a significant 3P reserves position of 84.7mmboe when including the recently acquired additional interests in the Sugarkane AMIs. The Longhorn AMI represents roughly half of the reserves base, with liquids reserves representing roughly 60% of total reserves as a result (see Figure 25). The company's 2P reserves currently only represent 15% of 3P reserves; Aurora anticipates the majority of 3P reserves will be converted to 2P over the coming 12 months as a result of the aggressive drilling program.

Aurora is trading on an enterprise value to proved and probable (2P) reserves ratio of USD93/boe. We do recognise however, that there are issues with the use of this ratio to identify undervalued stocks given that it ignores the quality and value of reserves. The key parameters overlooked (or simplified) are the product mix and mix of developed and undeveloped reserves. By including development costs in the enterprise value we feel we largely remove the issue of developed versus undeveloped reserves, however, the product mix seriously undermines the use of this metric given the various hydrocarbon products have significantly different values. We estimate this decreases significantly to USD23.2/boe when including 3P reserves (gross of royalties) plus the required development costs to commercialise the Sugarkane 3P reserves (see Figure 26).

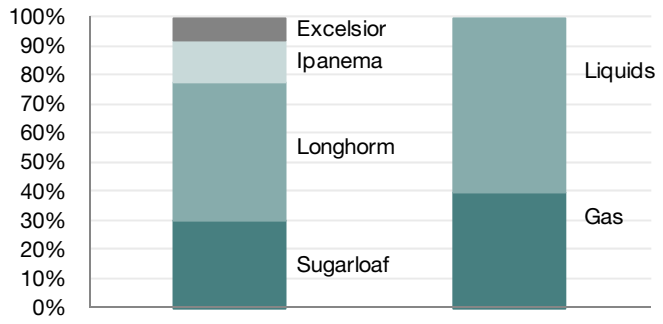
Table 10: AUT – reserves summary, as at 1 July 2010 (AUT share)*

Area	Liquids (mmbbl)	Sales Gas (bcf)	Total (mmboe)
Proved and probable (2P)			
Sugarloaf	4.26	28.9	9.1
Longhorn	2.02	7.1	3.2
Ipanema	0.14	1.8	0.4
Excelsior	0.0	0.0	0.0
Total proved and probable	**6.4**	**37.7**	**12.7**
Proved, probable and possible (3P)			
Sugarloaf	12.91	77.1	25.8
Longhorn	28.46	68.9	39.9
Ipanema	4.52	47.4	12.4
Excelsior	5.15	8.4	6.6
Total 3P reserves	**51.0**	**201.7**	**84.7**
Total 3P Reserves (pre-royalty)	68.1	269.0	112.9

Source: Company data, CBA

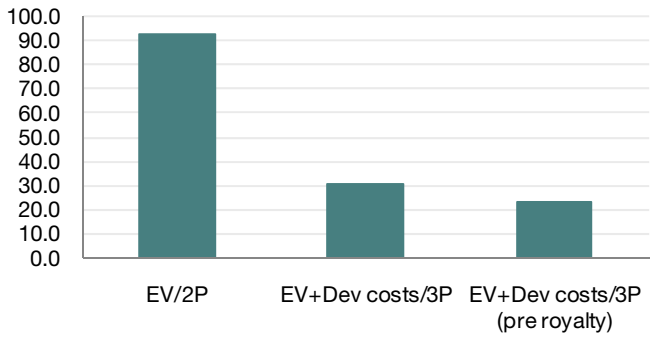
*Note: *Adjusted for the acquisition of additional interests in Sugarkane gas and condensate field AMIs*

Figure 25: AUT – reserves breakdown (3P)



Source: Company data, CBA

Figure 26: AUT – EV/Reserves (USD/boe)



Source: Company data, CBA

*Note: *As at 15 February 2011*

Earnings and returns

Earnings outlook

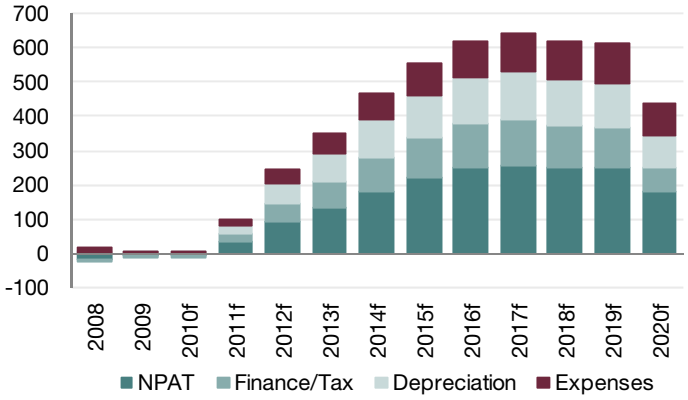
We forecast Aurora to report a modest loss in FY10, with production and revenue only recently commencing post-Hilcorp's farm-in cost recovery (see Table 11). We forecast material earnings growth as the company commercialised the Sugarkane field over the course of the decade. In-line with the production forecast, earnings are set to peak in 2017 on the completion of drilling activity. The Longhorn AMI offers the most material contribution to our earnings forecast given Aurora's high interest in the field and the area's relatively high liquids content.

Table 11: AUT – earnings forecast and breakdown

Profit & Loss (USDm)	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
WTI oil price (USD/bbl)	99.7	61.8	78.8	99.6	100.8	94.2	95.6	100.7	104.0	104.8	104.7	104.5	104.1
Henry Hub (USD/mmbtu)	8.9	3.9	4.6	5.6	5.7	5.3	5.4	5.7	5.9	5.9	5.9	5.9	5.9
Exchange rate (AUD1:USD)	0.85	0.79	0.91	0.97	0.87	0.85	0.85	0.85	0.85	0.84	0.82	0.80	0.78
Revenue													
Gas Sales	1	0	0	16	40	60	82	97	107	110	98	94	70
LPG Sales	0	0	0	9	22	33	45	54	60	62	59	58	44
Oil/Condensate Sales	0	0	1	74	184	260	343	408	452	472	463	462	327
Total Sales Revenue	**1**	**0**	**1**	**99**	**246**	**353**	**470**	**558**	**619**	**644**	**619**	**614**	**442**
Operating Expenses	-1	-1	-1	-15	-37	-55	-75	-90	-102	-110	-110	-113	-92
Exploration Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
Impairment Losses	-10	0	0	0	0	0	0	0	0	0	0	0	0
Other Net Expenses	-1	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
EBITDA	-11	-3	-2	82	207	295	393	466	514	532	507	499	347
Depn & Amortisation	-5	0	0	-23	-56	-85	-111	-124	-132	-137	-131	-130	-92
EBIT	-15	-3	-2	59	151	210	282	342	382	395	376	369	255
Net Interest	1	0	0	-1	-3	-2	-1	1	4	7	12	17	22
Profit before tax	-15	-3	-2	58	148	208	280	343	385	402	388	385	277
Tax expense	0	0	0	-20	-52	-73	-98	-120	-135	-141	-136	-135	-97
NPAT	**-15**	**-3**	**-2**	**38**	**96**	**135**	**182**	**223**	**250**	**262**	**252**	**251**	**180**
Preference Div Paid	0	0	0	0	0	0	0	0	0	0	0	0	0
Exceptional Items	0	0	0	0	0	0	0	0	0	0	0	0	0
NPAT Underlying	**-15**	**-3**	**-2**	**38**	**96**	**135**	**182**	**223**	**250**	**262**	**252**	**251**	**180**
Divisional EBIT													
Sugarloaf	0	0	1	14	28	52	73	90	101	108	112	115	99
Longhorn	0	0	0	37	96	118	146	174	192	201	206	205	111
Ipanema	0	0	0	7	20	30	44	55	61	57	28	18	13
Excelsior	0	0	0	3	9	13	21	26	30	31	32	33	34
Other	-15	-3	-3	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
Total EBIT	**-15**	**-3**	**-2**	**59**	**151**	**210**	**282**	**342**	**382**	**395**	**376**	**369**	**255**

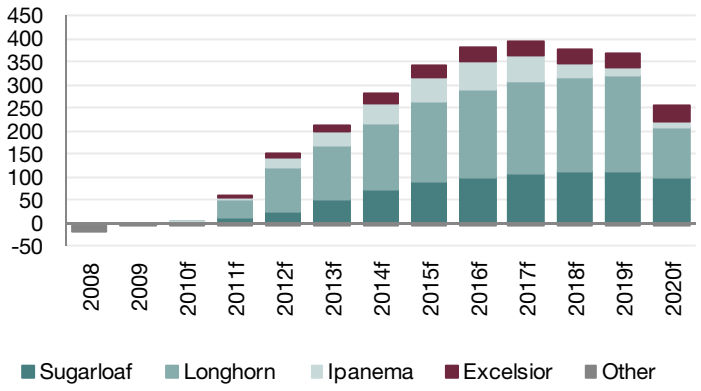
Source: Company data, CBA

Figure 27: AUT – NPAT breakdown (USDm)



Source: Company data, CBA

Figure 28: AUT – EBIT breakdown (USDm)



Source: Company data, CBA

Returns and other metrics

As also highlighted in the previous table, we forecast earnings growth of roughly USD37m per annum over the FY10-FY17 forecast period (see Table 12). ROE is also material over the remainder of the decade averaging 22% per annum over 2011-2020.

Table 12: AUT – Performance metrics*

Performance Metrics	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Production (mmboe)	0.0	0.0	0.0	1.4	3.5	5.5	7.2	8.1	8.7	8.9	8.4	8.3	6.1
Normalised profit (USDm)	-14.6	-3.0	-2.0	37.8	96.2	135.3	182.1	222.7	250.3	261.6	252.3	250.6	180.1
Normalised EPS (USc)	-7.2	-1.5	-0.7	9.6	23.5	33.1	44.5	54.4	61.2	63.9	61.6	61.2	44.0
EPS growth (%)		n/a	n/a	n/a	146%	41%	35%	22%	12%	4%	-4%	-1%	-28%
CFPS (USc)	-0.3	-1.0	-0.8	6.9	32.8	48.4	65.7	80.2	90.7	96.4	95.3	93.6	76.1
FCFPS (USc)	-5.2	-2.1	-2.8	-19.6	4.4	9.6	24.1	37.5	46.9	54.2	57.6	56.9	66.7
DPS (USc)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P/E (x)	n/a	n/a	n/a	30.1	11.3	8.0	6.0	4.9	4.3	4.1	4.1	4.0	5.5
P/CF (x)	n/a	n/a	n/a	42.0	8.1	5.5	4.0	3.3	2.9	2.7	2.7	2.6	3.2
P/FCF (x)	n/a	n/a	n/a	n/a	60.1	27.6	11.0	7.1	5.6	4.8	4.4	4.3	3.6
Dividend yield (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Franking (%)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
EV/EBITDA (x)	-1.7	-17.6	-638.6	14.2	5.1	3.4	2.3	1.6	1.1	0.6	0.1	-0.4	-1.4
ROE (%)	-45%	-13%	-2%	16%	29%	30%	30%	28%	24%	20%	16%	14%	9%

Source: Company data, CBA

*Note: *As at 15 February 2011*

Balance sheet and cash flow

Aurora currently has a USD90m cash balance which will meet forecast capital expenditure requirements in 2011. The company is likely to introduce debt financing as the Sugarkane development matures. Beyond 2011 we see Aurora as adequately funded to meet capital expenditure requirements for its existing portfolio of development opportunities (see Table 13). Further equity raisings can't be ruled out to fund acquisitive growth.

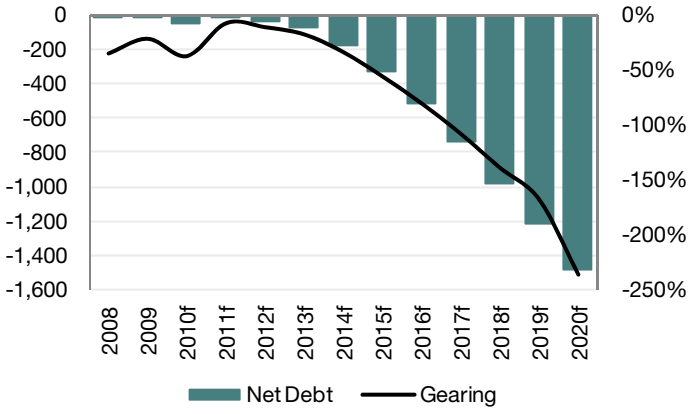
Table 13: AUT – Balance sheet and cash flow

Balance Sheet (USDm)	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Cash & deposits	6	4	55	69	87	127	225	379	571	793	1,029	1,261	1,509
Debt	0	0	0	50	50	50	50	50	50	50	50	50	25
Shareholders' equity	21	24	201	280	377	512	694	917	1,167	1,428	1,681	1,931	2,111
Total assets	22	25	201	337	441	584	774	1,003	1,258	1,523	1,775	2,027	2,174
Net debt / (Net debt + equity)	-35%	-22%	-37%	-7%	-11%	-18%	-34%	-56%	-81%	-108%	-139%	-168%	-237%
EBITDA / gross interest (x)	-79.4	-17.0	0.0	40.8	51.7	73.8	98.1	116.4	128.5	132.9	126.8	124.7	115.7

Cashflow (USDm)	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Profit after taxation	-15	-3	-2	38	96	135	182	223	250	262	252	251	180
D & A, Impairments	15	1	1	23	56	85	111	124	132	137	131	130	92
Exploration Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital Movements	0	0	-1	-33	-18	-22	-24	-18	-12	-4	7	3	39
Other	-1	0	0	0	0	0	0	0	0	0	0	0	0
Cash from operating activities	-1	-2	-2	27	134	198	269	328	371	394	390	383	311
Development capex	-10	-2	-6	-104	-116	-159	-170	-175	-179	-172	-154	-151	-38
Exploration capex	0	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions/other	1	0	-120	0	0	0	0	0	0	0	0	0	0
Net investing cash flows	-9	-2	-126	-104	-116	-159	-170	-175	-179	-172	-154	-151	-38
Net financing cash flows	0	0	178	92	0	0	0	0	0	0	0	0	-25
Net change in cash	**-9**	**-5**	**50**	**15**	**18**	**39**	**99**	**154**	**192**	**222**	**236**	**233**	**248**

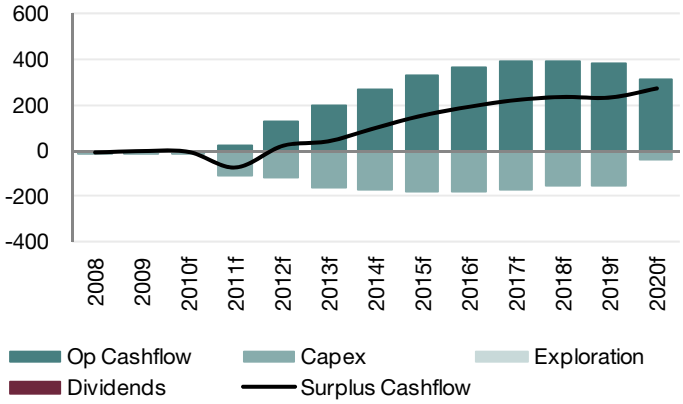
Source: Company data, CBA

Figure 29: AUT – Net debt to equity (%) and Net debt (USDm)



Source: Company data, CBA

Figure 30: AUT – Cash flow (USDm)



Source: Company data, CBA

Valuation

DCF valuation breakdown

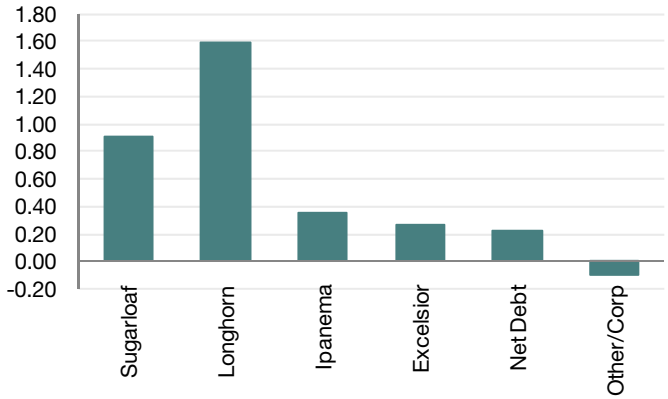
In terms of valuation breakdown, the Longhorn AMI is the core contributor to our valuation, making up over 50% of our valuation of the company operations. Our DCF valuation is based on the following assumptions: WACC 10.0%, risk-free rate 5.5%, equity risk premium 6.0% and beta 1.25.

Table 14: AUT – DCF net asset valuation

AUT Valuation	AUDm	AUDps	Risk	Production mmboe	AUD/boe
Sugarloaf	371	0.91	100%	28	13.3
Longhorn	649	1.59	100%	44	14.7
Ipanema	146	0.36	100%	13	10.9
Excelsior	107	0.26	100%	7	14.5
Total Operations	**1,272**	**3.11**		85	14.9
Other Assets	4	0.01			
Net Cash/(Debt)	93	0.23			
Corporate	-44	-0.11			
Total Valuation	**1,325**	**3.24**			

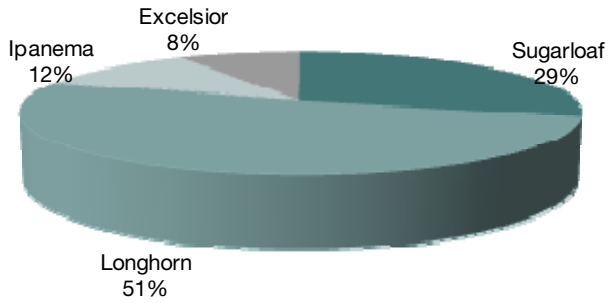
Source: Company data, CBA

Figure 31: AUT – DCF valuation breakdown (AUDps)



Source: Company data, CBA

Figure 32: AUT – DCF valuation breakdown (ex net debt and other/corporate) (%)



Source: Company data, CBA

Valuation sensitivities

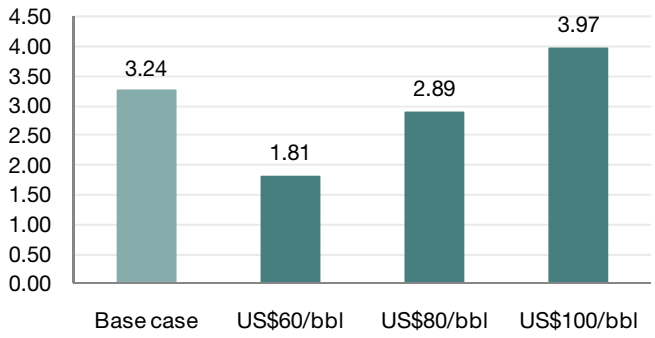
We project our DCF-based valuation for Aurora on a range of oil price assumptions. Despite having a modest portion of the business exposed to gas prices, the company is highly leveraged to movements in forecast oil prices (see below).

Table 15: AUT – DCF net asset valuation sensitivities (AUDps)

Total DCF net asset value	**3.24**
WTI oil price sensitivity (2010 real)	
USD60/bbl	1.81
USD80/bbl	2.89
USD100/bbl	3.97
Discount rate sensitivity	
8%	3.74
10%	3.25
12%	2.84

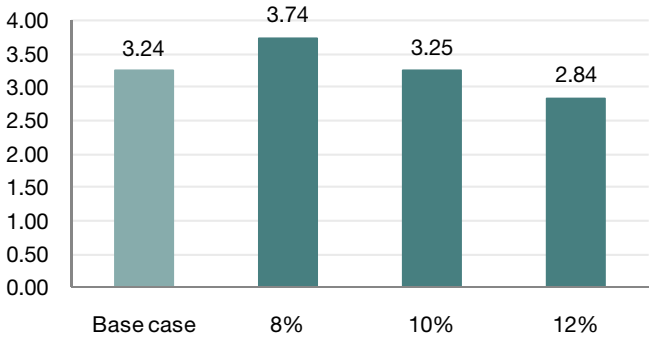
Source: Company data, CBA

Figure 33: AUT – valuation WTI oil price sensitivities (AUDps)



Source: Company data, CBA

Figure 34: AUT – valuation WACC sensitivities (AUDps)



Source: Company data, CBA

Current recommendation definitions

CBA Institutional Equities Investment recommendations are determined by the covering analyst and reflect the analyst's assessment of a stock's expected total shareholder return (TSR). TSR is calculated as the difference between the analyst's 12-month price target and the current share price plus the forecast dividend yield.

Buy: Stocks with a Buy recommendation represent the most attractive stocks under the analyst's coverage. They are forecast to generate significantly positive expected total shareholder returns.

Hold: Stocks with a Hold recommendation are less attractive than stocks with a Buy recommendation. They are forecast to generate flat to slightly positive expected total shareholder returns.

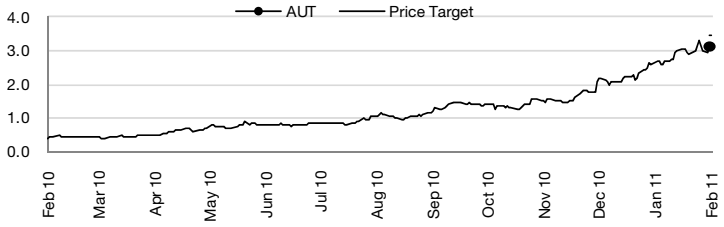
Sell: Stocks with a Sell recommendation are the least attractive stocks. They are forecast to generate flat or negative expected total shareholder returns.

Note: CBA's previous recommendations prior to 25 January 2010 were:

Short term (over 6 months): Buy – appreciate by >10%, Accumulate – increase between 2% and 10%, Reduce – increase by less than 2% or fall by up to 5%,Sell – fall by >5%.

Long term (24 months) Outperform (O / P) – exceed market return by >5%, Market Perform (M / P) – be in line with market return, +/-5%, Under Perform (U / P) – be less than market return by >5%.

One year history of price target and recommendation changes



Date	Price Target ($)	Recommendation
15/02/2011	3.45	BUY

Source: CBA, IRESS

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