EASTERN AUSTRALIA
Upstream Gas Report

CORPORATE ACTIVITY

Beach Energy

27 NOV: Beach Energy advised that it had appointed Robert Cole as its new MD, effective from 1 June 2015. Mr Cole was previously an Executive Director at Woodside Petroleum with the position Executive Vice President, Corporate and Commercial. He will replace current Beach MD Reg Nelson who is retiring after leading the company since 1995. In that time Beach bought Delhi Petroleum and a 21% interest in the Cooper Basin JVs, pioneered the Western Flank oil play in the Cooper, made a large profit out of its investment in the Tipton West CSG Field and has become one of Australia's leading shale and tight gas explorers.

Senex Energy

19 NOV: Senex Energy Chairman Denis Patten advised that he would step down from his role in the coming months, remaining on the company's Board as a non-executive Director. Mr Patten has chaired Senex and its predecessor company Victoria Petroleum since 2008.

AGL Energy

18 NOV: AGL Energy announced the appointment of Andrew Vesey as the company's new CEO, effective 11 February 2015. He will replace retiring MD and CEO Michael Fraser, who has led AGL since 2007. Mr Vesey is currently Executive Vice President and COO of the Arlington, Virginia-based global power generation and distribution company The AES Corporation and has previously worked in Australia as MD and CEO of Victorian network company Citipower.

AGL reverted to its historic 'AGL' code on the ASX on the 24th of November, after being listed as 'AGK' since its demerger from Alinta in 2006. AGL's predecessor company the Australian Gas Light Company was first listed on the Sydney Stock Exchange under the 'AGL' code in 1871.

LNG

GLNG

26 NOV: Santos advised that it expected to produce the first LNG from Train 1 of the GLNG project in the second half of 2015 after the first commissioning gas is introduced to the plant in December this year. After LNG production commences the train should ramp-up to plateau production levels over the following three to six months. Train 2 of the development should be ready for start-up by the end of 2015 with production to ramp-up over the next two to three years.

PIPELINES

NEGI

12 NOV: The NT Government formally invited Expressions of Interest from private companies interested in building its proposed North East Gas Interconnector (NEGI) pipeline link. The Government hopes to select a company or consortium to build the pipeline early next year. It has identified two potential routes to link the NT and east coast pipeline networks and allow NT gas to flow to higher priced east coast markets, a link from the Amadeus to Darwin Pipeline to Moomba and a link from the Amadeus to Darwin Pipeline to the Carpentaria Gas Pipeline at either Mt Isa or Boulia.

GOVERNMENT

Victoria

29 NOV: Victoria saw a change of government at its state election as the Liberal National Coalition of Denis Napthine was defeated. There will be no immediate respite for onshore explorers in the state with new Labor Premier Daniel Andrews supporting the Coalition Government's repeatedly extended drilling moratorium from opposition. Labor has pledged to hold a yearlong parliamentary inquiry to investigate the impacts of CSG and unconventional gas exploration before it considers allowing any exploration in the state. The Coalition's drilling moratorium, first imposed in 2012, was scheduled to expire in July next year after the conclusion of a community consultation program and the release of a benchmarking report on the state's underground water. At this early stage of the new government the only thing clear is that there will be no easy path to exploration activity the likes of Lakes Oil, Beach Energy and Cooper Energy.

New South Wales

12 NOV: The NSW Government released the NSW Gas Plan, its policy response to the Chief Scientist and Engineer's report into CSG operations in the state. Professor Mary O'Kane released the final report from her review at the end of September, finding that although CSG activities in the state posed some technical challenges and risks these could be effectively managed. Professor O'Kane made sixteen recommendations to improve clarity and communication surrounding the CSG industry, improve legislative and regulatory oversight of the industry and improve management and oversight of the impacts and risks associated with CSG activities.

The Government has accepted all of the recommendations from the review in principle and the Gas Plan sets out its response to each. Although the Government expresses support for the further development of the gas industry in the Plan some of the policies included will impose further difficulties on the industry.

The Plan will appoint the state's EPA as the lead regulator for gas exploration and production activity, responsible for compliance and enforcement of approval conditions. This reflects Professor O'Kane's recommendation that there be a single independent regulator for CSG. The Government gave a lukewarm response to the Professor's recommendation that the state move to a single legislative act for all onshore subsurface resources (other than water), stating only that it will work to consider the best approach to effecting this.

The Gas Plan was supportive of the call for more transparency in all licences and approvals and monitoring data, with the Government currently scoping a whole-of-government environmental data portal that should facilitate this. The Plan is also supportive of more transparency and assistance regarding compensation for landholders affected by CSG activity with NSW's Indpendent Pricing and Regulatory Tribunal to annually benchmark compensation rates. A Community Benefits Fund will also be established with the Government and gas companies to voluntarily fund projects in communities where gas exploration occurs.

Other measures that will be introduced as part of the Plan may have a restrictive effect on exploration activity within the state. The Government will introduce legislation to cancel all outstanding Petroleum Exploration Licence application areas (PELAs) and Petroleum Special Prospecting Authorities. This will result in the cancelling of 16 PELAs and the area of the state covered by titles and applications will decrease from around 60% to 15%. The Government will also offer to buy back already issued PELs for limited compensation. Any future land releases will only occur after a new Strategic Release Framework is developed, and will only be in areas approved by the Minister of Resources and Energy, after considering economic, environmental and social factors. The process will include holding community consultation before any land release, likely allowing anti-CSG groups to mobilise and apply political pressure to attempt to prevent the release occurring.

Perversely, after repeatedly introducing moratoriums preventing CSG activity from being undertaken, the Government is now complaining that there are only three active CSG projects in the state and will introduce a 'use it or lose it' policy as part of the Gas Plan. By the end of 2015 titleholders will need to commit to substantial investment in their acreage or the Government may cancel their permits. For gas projects that manage to progress towards development the Government may designate them as Strategic Energy Projects providing assistance in gaining approvals, but only if a substantive amount of gas is committed to the NSW market.

Although the NSW Government's Gas Plan includes a welcome call of support for CSG in the state it imposes further layers of regulation and will likely restrict exploration activity outside already granted exploration licences. The state's long suffering explorers will hope that the plan is the last in a series of more restrictive policies implemented by the Government and that they can at last focus on bringing on the gas supply that NSW needs.

CORPORATE ACTIVITY

Central Petroleum

11 NOV: Central Petroleum announced that it had signed a non-binding HOA with Incitec Pivot for the supply of up to 15 PJ/year of gas for ten years from conventional reservoirs in the Amadeus Basin. The gas would be transported from the NT through the proposed North East Gas Interconnector pipeline to Incitec's operations in Queensland. An ex-field price for the gas has been agreed between the companies and the agreement calls for Incitec to assist in securing funding for drilling and reserves certification. Central expects that further exploration drilling at the Palm Valley and Dingo fields as well as drilling new gas prospects will allow it to prove up enough gas to fulfil the agreement. Palm Valley currently produces around 1 PJ/year and Dingo is currently being developed to supply 1.5 PJ/year to NT's Power and Water Corporation. Established reserves at both fields are small with 2P reserves of 30 PJ at Dingo and 24 PJ at Palm Valley.

UIL Energy

4 NOV: UIL Energy was admitted to the official list of the ASX with code 'UIL'. The company raised $4.2m through the offer of 21m shares at $0.20, giving it an initial market capitalisation of $21.6m with its total share capital of 108m shares. UIL is focused on unconventional and conventional prospects in WA's Perth and Canning Basins and has net acreage of 0.5m and 3.7m acres in the two basins respectively. It plans to acquire seismic in one of its Perth Basin tenements next year with the aim of attracting a farm-in partner to fund drilling. The company's MD is former Bow Energy CEO John De Stefani with prominent CSG investor Stephen Bizzel a non-executive Director. At the end of November the company's share price had been hit by the general sell off of Australian energy companies, dropping to $0.135.

EXPLORATION AND APPRAISAL

Buru Energy

28 NOV: Buru Energy advised that it had finished wellsite preparation works and undertaken diagnostic testing at the Asgard-1 and Valhalla North-1 wells in preparation for them to be fracture stimulated and tested in the Canning Basin dry season next year. The results of the fracc program will be an important milestone in Buru's aim to progress the Laurel Formation tight gas play. The company's previous exploration has defined a large extensive gas resource with an important liquids component, the next step is to move to the appraisal stage and start experimenting with fracc and production well designs before a full pilot program can commence. Buru completed a three stage fracc of the Laurel Formation in the Yulleroo-2 well in 2010, recording gas flows of up to 1.6 MMscfd with around 25 bbls/mmcf of condensate and 25 bbls/mmcf of LPG.

Linc Energy

27 NOV: Linc Energy reported oil shows in the Stuart Range shale formation in its Pata-1 exploration well in the Arckaringa Basin. The well intersected a 143 m thick section of the Stuart Range from 1,039 m with drilling of the well continuing to a planned total depth of 2,345 m through the Boorthanna and Pre-permian Formations. Pata-1 is the first of a three well program planned for the South Australian basin, which Linc refers to as 'the 103 Billion Barrel* Arckaringa Basin' after a DeGolyer and McNaughton study released in 2013 estimated it may contain an unrisked prospective resource of that size.

Strike Energy

27 NOV: Strike Energy reported that it had completed drilling the Klebb-2 and Klebb-3 wells at its Southern Cooper Basin Deep CSG Project. The company will soon begin production testing the wells, joining the already under test Klebb-1 and Le Chiffre-1 wells. With the targeted Patchawarra coals at depths of some 2,000 m displaying relatively high permeabilities of around 20 mD Strike is testing some of the wells with fraccs and some with simple perforations. Water is being pumped from the two wells under test with gas flows to surface already observed. Strike has an ambitious development target for the deep CSG project, aiming to establish 2P reserves and sanction a development project during 2015 to allow first commercial production in 2017. Its expenditure in the project may be partially funded by potential customer Orica under a gas pre-sales agreement. Strike owns 67% of the project with Energy World Corporation holding the remaining 33%.

Beach Energy

25 NOV: Beach Energy advised that it had completed a four well fracture stimulation program in ATP 855P in the Queensland section of the Nappamerri Trough and had commenced flow testing two of the wells. Hervey-1 was subject to a five stage fracc, with one Patchawarra Formation stage, one Daralingie Formation stage and three Toolachee Formation stages. Initial flow testing on a 22/64" choke resulted in a 0.4 MMscfd gas flow at 50 psi, with stimulation fluids also flowing. The well is now on a 40/64" choke, flowing at 0.2 MMscfd. Beach advised that the low pressure results support its belief that basin centred gas play formations in the shallower south-eastern section of the Nappamerri are less overpressured than other areas of the trough.

The Etty-1 well was fracced over four stages with one in the Daralingie and three in the Toolachee, in flow testing it came on at 0.4 MMscfd before increasing to 0.87 MMscfd at a pressure of 570 psi with continuing recovery of stimulation fluids; most of the gas flow is from the Daralingie zone. Beach identified this as a potential new sweetspot within the project that could be tested with a horizontal well. Testing will soon commence at Redland-1 and Geoffrey-1 with Beach also to fracc and test Boston-2 in the South Australian section of the Nappamerri.

Beach reported the compositions of gas recovered from wells in the Nappamerri for the first time, confirming high carbon dioxide content within the gas. Harvey-1 produced gas with 69% methane and 31% carbon dioxide with Etty-1 gas 68% methane and 32% carbon dioxide. High levels of CO_2 in gas produced from REM shale formations are also likely to be confirmed by Beach at some stage. The high carbon dioxide content in the Nappamerri gas will result in higher capital and operating costs for any potential production development as a result of the costs associated with removing CO_2 from the raw gas stream. Santos is currently investing $320m to construct the Train 8 CO_2 removal unit at Moomba without any increase in the overall treated gas output from the plant. The new unit will handle the change from raw gas with 12-15% CO_2 streams to those with >25% CO_2. Any future requirement to pay for CO_2 emissions or to sequester some or all carbon would add further to Nappamerri development costs.

Beach's current activity in the Nappamerri will complete the first stage of Chevron's farm-in to the acreage, which involved drilling 18 wells and fraccing 14 of them. Chevron is to make a decision on committing to the second stage of its farm-in to Nappamerri acreage in both South Australia and Queensland by the end of March next year. This would see the US company commit to a further US$124m of funding. Beach plans to continue appraisal even if Chevron does not commit, with the next stage of activity focussing on improving well recoveries.

Senex Energy

18 NOV: Senex Energy advised that it would bring the Hornet-1 well into production after installing surface facilities and completing a pipeline tieing the well into the SACB JV Allambi field. Gas will be sold to the SACB JV under an agreement allowing Senex to sell up to 10 Mmscf/day of raw gas while it tests the Hornet field. The company flow tested the well at a rate of more than 2 Mmscf/day, after fraccing it in 2013. A second well at the field, Kingston Rule-1, is awaiting a workover before it is expected to also come onto production. Senex has established a 2C contingent resource of 835 bcf at the Hornet field, a tight gas reservoir in the Patchawarra and Epsilon Formations located within a stratigraphic trap. Gas from the field may also contain around 10 to 20 bbls/mcf of condensate.

Real Energy

10 NOV: Real Energy released an internal estimate of a more than 1 tcf 3C contingent resource in its eastern Cooper Basin tenement ATP 927. The company has drilled two wells in the tenement, intersecting gas saturated sections in the Toolachee and Patchawarra Formations outside any structural closure. It plans to further test this basin centred gas play when it flow tests the wells next year.

Central Petroleum

7 NOV: Central Petroleum advised that it had drilled the Gaudi-1 well in the Georgina Basin to a total depth of 2,430 m, intersecting 300 m of the Lower Arthur Creek shale formation. Gas shows were observed in the shale and core was taken, along with core from the Thorntonia Limestone. Central plans to fracc and test Gaudi-1 next year after the wet season along with the partially drilled Whitely-1 well. The wells are located in the Queensland section of the basin with the activity being funded by Total under a farm-in.

OIL PRICE SLIDE

Oil prices continued to slide through November, with no rebound after OPEC met and maintained their collective production quota at thirty million barrels per day. Brent crude spot prices are now down to just over US$70, after trading at US$115 as recently as June this year. Prices look likely to remain depressed in the short to medium term as US shale production continues to increase and OPEC holds its production steady. This will have a significant impact on the Australian onshore oil and gas industry, even if a decline in the US/AUS exchange rate has slightly softened the impact of the oil price fall. This has been reflected in the share prices of Australian energy stocks, most of which have fallen sharply. The oil price decline is particularly bad timing for BG Group, Santos and Origin Energy, all gearing up to begin first exports of CSG through Gladstone LNG developments within the next year, after years of sustained investment. The lower oil prices will lead to a drop in capital investment in onshore Australia and may further slow the development of unconventional resources. Even before the oil price drop ConocoPhillips and PetroChina had pulled out of New Standard Energy's Goldwyer shale play, the investment required and the potential development timeline too high and long dated for the two majors. In a new environment of lower capital expenditure projects like the Goldwyer will find it very difficult to source funding.

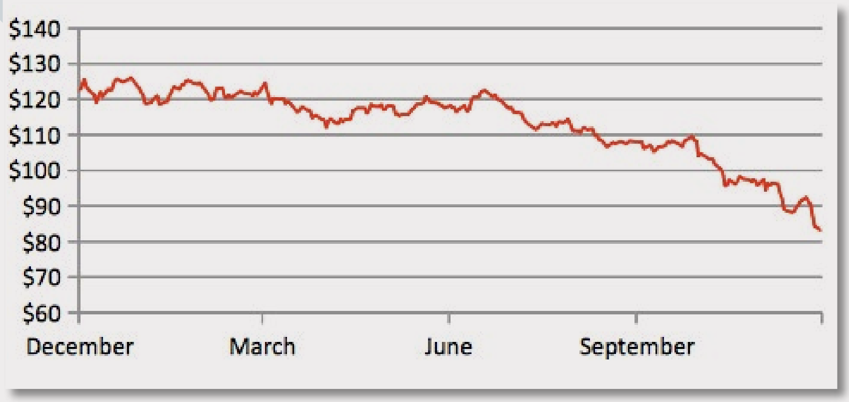
With Australian LNG sales contracts usually priced with a link to the Japanese Customs-cleared Crude (JCC) price, itself closely correlated with Brent Crude, LNG exporters will be seeing lower returns for their product. Santos, as operator and 30%-owner of GLNG, already considered the least profitable of Queensland's LNG developments, has been hit particularly hard by the oil price slide. The company's debt burden has grown substantially as it funded its share of GLNG's US$18.5b budget, as well as its 13.5% interest in the recently completed PNG LNG project. Santos can now expect lower revenues from its LNG and oil assets just as it was anticipating paying down debt and increasing its dividend payout. The company has now said that it will significantly reduce capital and operating expenditure in 2015.

With continuing investment in Queensland CSG and Cooper Basin conventional gas required to satisfy GLNG sales contracts ongoing investment in a number of Australian unconventional plays is likely to come under scrutiny. Santos was planning to continue high levels of investment across Cooper Basin shale, basin centred gas and deep CSG as well as Amadeus Basin shale and tight gas and frontier exploration in the McArthur Basin shale play. Cuts or delays to some of these programs may now be in the offing. Expensive continued development of the Narrabri CSG project may also be scrutinised, particularly as NSW Government support for CSG continues to be less than reliable. The pressure on Santos from the oil price fall could lead to delays in some Australian unconventional projects, its more speculative and longer term investments. With its share price declining to less than $9 Santos is at five year lows and its market cap has dropped to $8.5b.

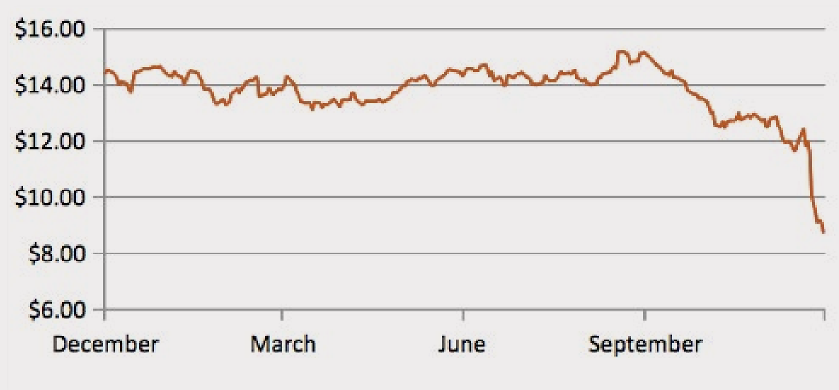
As a diversified energy supplier with extensive retail and generation assets Origin Energy is less impacted by the oil price than Santos, however the company's share price has still declined substantially from recent highs. Origin was recently forecasting around US$1b in distributable cash flow from its 37.5% stake in APLNG from FY2017 when both of the project's trains will be producing at plateau but this was based on forward oil price curves in May this year, when Brent was still above US$100 and had not begun its decline. If the oil price does not recover Origin will have less APLNG cash to distribute to shareholders and for further investment. The company will also see lower returns in the short term from APLNG's ramp-up gas supply contracts to QCLNG and GLNG, with price for these contracts linked to oil. Origin has yet to make significant investments in Australian unconventional exploration although the company has recently farmed-in to the Patchawarra Trough tight gas play in the Cooper Basin and the Beetaloo Basin shale play, with deals that could see it spend hundreds of millions of dollars. It's probably too early to say if Origin's commitment to frontier Australian unconventional exploration could be affected by the oil price slide and potential reduced returns from LNG.

Brent US Dollar

Brent Spot US Dollar



Santos Closing Share Price



Beach Energy is Australia's largest onshore oil producer and has earned bumper profits from its position in the Western Flank of the Cooper Basin in recent years. Long serving MD Reg Nelson is sanguine about recent oil price weakness, considering Western Flank oil to be some of the most profitable in the world. However, much of the cash that Beach has earned has been ploughed into unconventional exploration, both in the various plays in the Nappamerri Trough and further afield in the onshore Otway and onshore Bonaparte Basins. Chevron has funded some of the Nappamerri expenditure under its farm-in agreement but the US major must commit to the next stage of the farm-in by March next year, or walk away from the play. With appraisal results from the Nappamerri positive but not unequivocal, question marks were being raised about Chevron's intentions even before the oil price slide. If the US company cuts back on its worldwide capital expenditure long term development projects like the Nappamerri play may be the first to face the chop. Beach may struggle to fund the next stage of appraisal of the play at the scale it has envisaged on its own, particularly if returns from the Western Flank are lower. Beach's share price is sharply down over the last four months, reflecting these concerns.

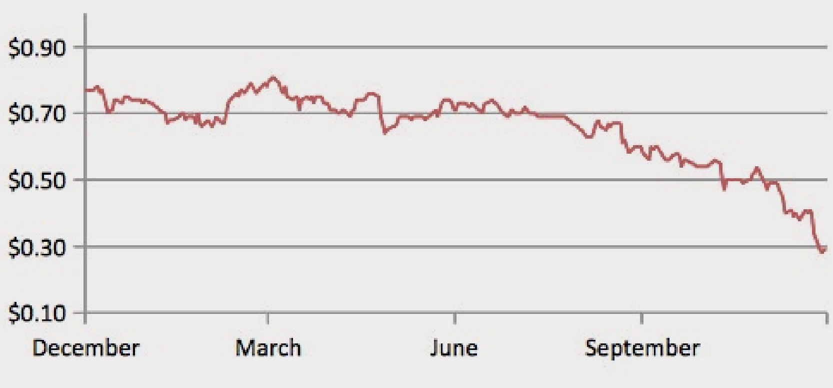
Measured on share price alone Senex Energy is being judged as one of the companies most affected by the oil price slide, its shares are down almost two thirds from highs in the last year. This may reflect the large number of development projects the company has, all requiring substantial levels of investment. The company has driven production at its Cooper Basin Western Flank oil assets sharply higher in the past few years but sustained investment is required to maintain and grow production. Senex quotes a cost base of just $31 per barrel excluding royalties for Western Flank oil ensuring good returns even at depressed oil prices but the company was also relying on this cash flow to fund appraisal and development of its extensive Cooper acreage including the Hornet gas field and also the recently acquired Western Surat CSG Project, centred on the Lacerta Field. Exploration of the company's acreage in the Patchawarra and Allunga Troughs for unconventional gas plays should soon commence as it will be funded by Origin Energy under a farm-out. Continuing lower oil prices may require Senex to scale back some of its ambitious development plans.

Drillsearch Energy has a similar focus to Senex, leveraging cash flow from Western Flank oil production to grow gas production in conventional and unconventional targets in the Cooper Basin. The company has also seen a large decline in its share price perhaps reflecting that companies with ambitious growth plans will be the most severely curtailed in a low oil price environment. Drillsearch has secured a number of farm-ins to some of its various plays, hopefully ensuring that larger companies carry most of the burden for future investment. This includes QGC in its Nappamerri acreage and Santos in its Patchawarra play and in Western Flank wet gas. Drillsearch has recently forecast capital expenditure on its own

Origin Closing Share Price

Beach Closing Share Price

Senex Closing Share Price



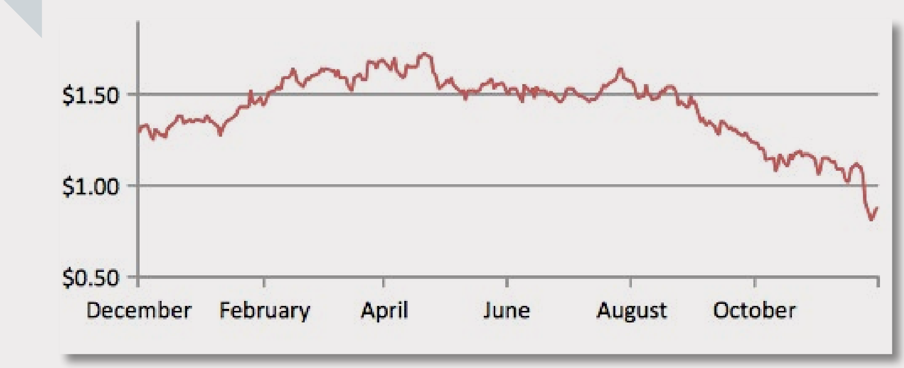
behalf of $130m - $170m in FY2015, significant investment with its market cap now down to around $410m. The company does have $150m cash on hand so funding this should not be an issue but it may be forced to scale back some of its growth plans in the medium term.

AWE is one of the more diversified medium sized Australian energy companies, with both oil and gas production across a number of fields. Continuing strong Australian gas prices should support the company even if cash flow from oil declines. Prior to the oil price drop the company's share price had been appreciating and it is still above its lows for the last year. The company should have no difficulties continuing to fund its Perth Basin exploration program with further testing of the exciting Waitsia conventional gas field due next year along with further shale and tight gas exploration. There may be more concern with AWE's planned investment in the Indonesian heavy oil field AAL, the company and partner Santos had hoped to sanction the field's development during 2015 but its economics will now need to be reassessed. Lower oil prices will also affect AWE's small minority interest in the Sugarloaf field in the Eagle Ford shale play but the company has not been taking any cash out of this asset so it should not have a large impact.

A sustained period of low oil prices may have the most impact on small companies focusing on Australian frontier unconventional exploration. In the last year or so the reality of the sustained investment and time that is required to progress a frontier play has gained wider recognition and even before the oil price slide some of these small explorers were suffering difficulties. With equity markets unwilling to provide meaningful funding, attracting larger farm-in partners has been the only option to advance exploration. This kind of long term investment and commitment will be the first area to face cutbacks when oil majors reduce capital investment. Armour Energy appeared to be struggling to attract a farm-in partner to its large northern Australian acreage position even before the oil price slide. The company has very little cash on hand and will not be able to fund exploration in its plays next year unless it attracts a partner soon. Unfortunately it may be very difficult in the current environment and the companies difficulties may continue. Its share price reflects this, down to just $0.06 for a market cap of less than $20m.

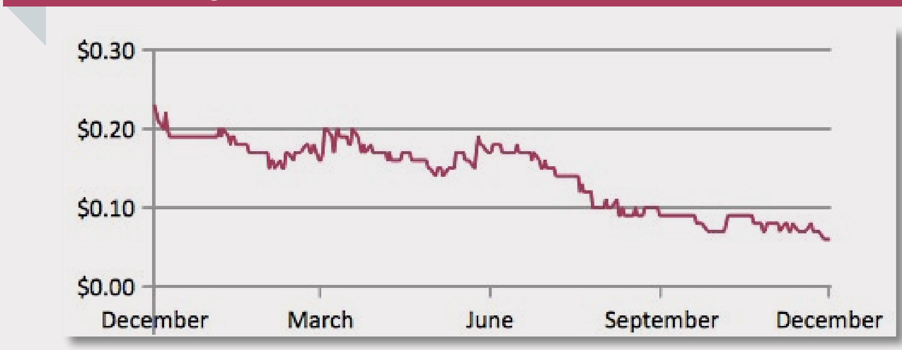
Central Petroleum has seen a precipitous decline in its share price this year. Exploration in its two flagship unconventional plays, in the Amadeus and Georgina Basins, is being funded by Santos and Total respectively but the staged nature of the farm-ins allow the partners opportunities to withdraw from the agreements. Santos has already reduced the number of permits covered by its farm-in and in the Georgina Statoil withdrew from the same play this year after disappointing exploration results. Central, led by the ever ebullient Richard Cottee, has responded by focusing on conventional gas targets the Amadeus, to be supplied to east coast markets through the proposed NEGI pipeline.

Drillsearch Closing Share Price



AWE Closing Share Price

Amour Closing Share Price

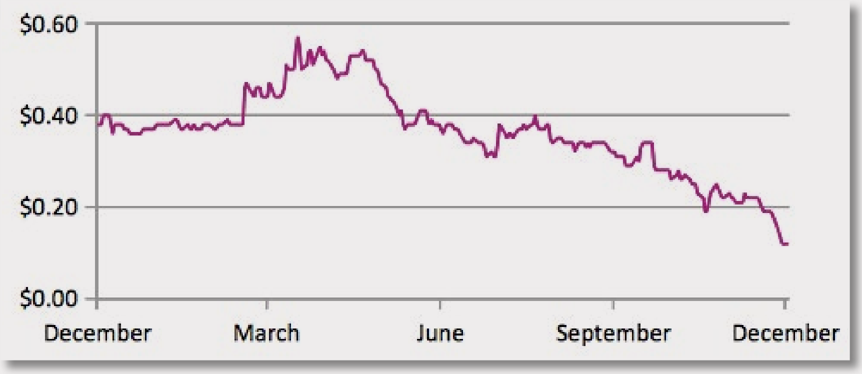


Central will need potential gas consumers like Incitec to stump up the funds for the exploration and appraisal of these targets. With the company's share price at less than $0.12 its market cap is around $43m.

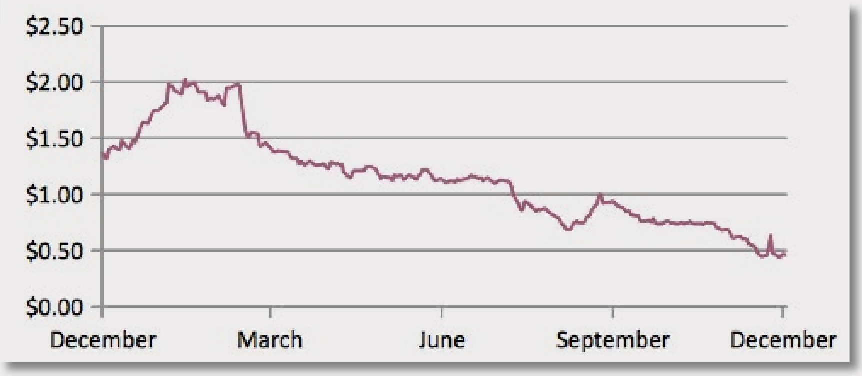
Buru Energy was already seeing a significant decline in its share price prior to the oil price slide. This reflected disappointments and difficulties with its Ungani oil field development and delays in its assessment of the Laurel Formation tight gas play. With returns from increased oil production likely to be lower the company will be hoping for positive results from its long awaited fracc and test of two Laurel play wells next year. With $60m in cash and support from long term farm-in partner Mitsubishi Buru may be well placed to weather a soft oil price for the next year or so. With its share price at $0.45 Buru's market cap is around $150m. This may better reflect the value of the company rather than recent share price highs of nearer to $2 and a market cap north of $500m.

New Standard Energy may be the small Australian explorer with the most to lose from a low oil price environment. Just as the company switched its focus to the Eagle Ford shale play and took on debt to fund drilling the oil price has crashed. Even before the oil price decline ConocoPhillips and PetroChina withdrew from the company's Goldwyer shale play. New Standard is now faced with trying to attract a new partner to fund exploration in the massive risk/massive reward play where a single vertical well can cost around $15m. The company's precipitous share price decline reflects the risks it faces. At $0.045 its market cap is just $17m.

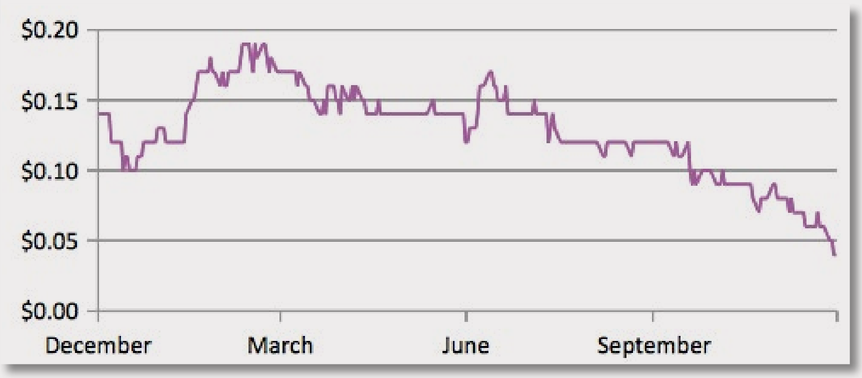
Central Closing Share Price



Buru Closing Share Price



New Standard Closing Share Price



EASTERN AUSTRALIA CSG:

Reserves at 31 December 2013, production second half 2013 Averages

Field	Ownership	State	Basin	Reserves (PJ) 1P	2P	3P	Production (TJ/day)	Tenure
AGL ENERGY								
Camden Gas Project	AGL Energy* 100%	NSW	Sydney		48	48	16	PPLs 1, 2, 4, 5; PELs 2, 4, 5, 267
Gloucester Basin Project	AGL Energy* 100%	NSW	Gloucester		454	565		PEL 285
Hunter Gas Project	AGL Energy* 100%	NSW	Sydney					PELs 4,267
Total for AGL Energy including projects operated by others					**1,824**	**3,447**	**32**	
ARROW ENERGY								
100% ownership of Arrow Energy LNG project								
Total for Arrow Energy				**669**	**9,494**	**13,970**	**71**	
BG GROUP								
94% ownership of QCLNG project operator								
Total for BG Group including projects operated by others				**3,096**	**10,326**	**18,876**	**121**	
BLUE ENERGY								
Sapphire Field	Blue Energy* 100%	Qld	Bowen		50	180		ATP 814P
Total for Blue Energy					**50**	**180**		
ERM POWER								
Clarence-Moreton	ERM Power *50% CMR 30%, Red Sky 20%	NSW	Clarence-Moreton		17	159		PEL 457
Total for ERM Power					**9**	**190**		
HARCOURT PETROLEUM								
Mungi/Harcourt	Harcourt*67.1% Mitsui 32.9%	QLD	Bowen	36	448	1,064	3	PL 94Sublease, ATP 56 4P
Timmy	Harcourt*62.9% Mitsui 37.1%	QLD	Bowen		67	175		ATP 602P
Total for Harcout Petroleum				**36**	**515**	**1,239**	**3**	
LANDBRIDGE GROUP								
Meridan	Landbridge* 51% Mitsui 49%	QLD	Bowen	93	680	1,524	8	PL 94, Coal Mining Leases
Paranui	Landbridge* 25.5% Mitsui 24.5% BG 50%	QLD	Bowen			270		ATP 769 W
Tibrook	Landbridge* 25.5% Mitsui 24.5% BG 50%	QLD	Bowen			152		ATP 688P W
Total for Landbridge				**47**	**347**	**885**	**4**	
ORIGIN ENERGY								
37.5% ownership of APLNG and project upstream operator								
Ironbark Project	Origin 100%				259	869		ATP 788P
Total for Origin Energy including projects operated by others				**1,718**	**5,543**	**7,416**	**135**	
SANTOS								
30% ownership of GLNG and project operator								
Narrabri CSG Project	Santos* 80% EnergyAustralia 20%	NSW	Gunnedah		1,141			PEL 238
Total for Santos including projects operated by others					**3,061**		**33**	
SENEX ENERGY								
Don Juan CSG Project	Senex Energy* 45%, Arrow Energy 55%	Qld	Surat		101	197		ATP 771P
Total for Senex Energy including projects operated by others					**157**	**358**		

QUEENSLAND CSG-TO-LNG PROJECTS:

APLNG (AUSTRALIA PACIFIC LNG PROJECT)

Ownership:	Origin Energy 37.5% / ConocoPhillips 37.5% / Sinopec 25%	**Site:**	Laird Point, Curtis Island
Operatorship:	Upstream and pipelines: Origin / LNG: ConocoPhillips	**Customers:**	Sinopec 7.6 MTPA for 20 years, Kansai 1.0 MTPA for 20 years
Status:	Train 1 first LNG mid-2015 Train 2 first LNG Q4-2015	**Reserves:**	1P: 4,581 PJ 2P: 14,091 PJ 3P: 17,459 PJ 2C: 2,679 PJ
Size:	2 x 4.5 MTPA LNG trains (four-train 18 MTPA ultimate potential)	**Production:**	333 TJ/day (121.8 PJ/year)

Major Fields	Ownership	State	Basin	Reserves (PJ)			Production (TJ/day)
				1P	2P	3P	
Spring Gully	APLNG* 96.6% Santos 3.4%	Qld	Bowen	162	2,31	5,104	129
Peat	APLNG* 100%	Qld	Bowen				9
Talinga/Orana	APLNG* 100%	Qld	Surat				115

ARROW ENERGY (ARROW ENERGY LNG PROJECT)

Ownership:	Shell 50% / PetroChina 50%	**Site:**	Boatshed Point, Curtis Island
Operatorship:	Arrow Energy	**Customers:**	None announced
Status:	EIS currently being undertaken	**Reserves:**	1P: 669 PJ 2P: 9,594 PJ 3P: 14,096 PJ
Size:	2 x 4 MTPA LNG trains (four-train 16 MTPA ultimate potential)	**Production:**	71 TJ/day (25.9 PJ/year)

Major Fields	Ownership	State	Basin	Reserves (PJ)			Production (TJ/day)
				1P	2P	3P	
Moranbah Gas Project	Arrow Energy* 50% AGL Energy 50%	Qld	Bowen	160	2,512	5,350	31
Blackwater	Arrow Energy* 100%	Qld	Bowen				
Comet	Arrow Energy* 100%	Qld	Bowen				
Norwich Park	Arrow Energy* 100%	Qld	Bowen				
Surat Basin Fields	Arrow Energy* 50%-100%	Qld	Surat				
Tipton West JV	Arrow Energy* 100%	Qld	Surat				25
Kogan North	Arrow Energy* CS Energy 50%	Qld	Surat				7
Daandine	Arrow Energy* 100%	Qld	Surat				27

GLNG (GLADSTONE LNG PROJECT)

Ownership:	Santos 30% / PETRONAS 27.5% / Total 27.5% / KOGAS 15%	**Site:**	Hamilton Point West, Curtis Island
Operatorship:	Santos	**Customers:**	PETRONAS and KOGAS both to take 3.5 MTPA for 20 years
Status:	FID taken January 2011, first LNG 2015	**Reserves:**	1P: 1,797 PJ 2P: 5,376 PJ 2C: 1,638 PJ
Size:	2 x 3.9 MTPA LNG trains (three-train 10 MTPA ultimate potential)	**Production:**	111 TJ/day (40.5 PJ/year)

Major Fields	Ownership	State	Basin	Reserves (PJ)			Production (TJ/day)
				1P	2P	3P	
Fairview	GLNG* 76.07% APLNG 23.93%	Qld	Bowen				105
Scotia	GLNG* 100%	Qld	Bowen				21
Arcadia	GLNG* 100%	Qld	Bowen				
Roma Shelf	GLNG* 100%	Qld	Surat				

QCLNG (QUEENSLAND CURTIS LNG PROJECT)

Ownership:	BG Group 90% Train 1 and 97.5% Train 2 / CNOOC 10% Train 1 / Tokyo Gas 2.5% Train 2	**Site:**	North China Bay, Curtis Island
Operatorship:	QGC (100%-owned subsidiary of BG Group)	**Customers:**	CNOOC 3.6 MTPA from Train 1 for 20 years, Tokyo Gas 1.2 MTPA from Train 2 for 20 years, Chubu Electric up to 20 cargoes over 20 years, BG portfolio supply: up to 1.7 MTPA to Quintero LNG in Chile to 2030, up to 3.0 MTPA to Singapore for 20 years
Status:	FID taken October 2010, first LNG 2014, second train to start-up a year later	**Reserves:**	1P: 3,096 PJ 2P: 10,326 PJ 3P: 18,876 PJ 2C: 13,700 PJ
Size:	2 x 4.25 MTPA LNG trains (three-train 12.75 MTPA ultimate potential)	**Production:**	121 TJ/day (44.2 PJ/year)

Major Fields	Ownership	State	Basin	Reserves (PJ)			Production (TJ/day)
				1P	2P	3P	
QGC Central Walloons	BG* 59.4%-100%	Qld	Surat				204
Berwyndale South	BG* 100%	Qld	Surat				67
Kenya-Argyle	BG* 59.4% APLNG 40.6%	Qld	Surat				126
Woleebee Creek	BG* 80% Toyota 15% CNOOC 4% Tokyo Gas 1%	Qld	Surat				
Lacerta	BG* 100%	Qld	Surat				
Bellevue	BG* 70.6% APLNG 30.4%	Qld	Surat				7
Paradise Downs	BG* 80% VicPet 20%	Qld	Surat				
Lawton	BG* 70% VicPet 30%	Qld	Surat				