EASTERN AUSTRALIA
Upstream Gas Report

CORPORATE ACTIVITY

Santos

23 JAN: Santos was reported to be seeking to attract another partner to participate in the development of the Narrabri CSG Project. The company owns 80% of the field with EnergyAustralia holding the remaining 20%. Santos inked an agreement with the NSW Government to fast track approvals for an initial 100 TJ/day Narrabri development in February last year but the aggressive timetable for the process has not been met. The agreement called for an EIS to be submitted last June and a final decision from the state's Planning Assessment Commission to be made by the 23rd of January this year. The company is still preparing the EIS, which is sure to generate strong opposition once it's released publically. Santos VP Eastern Australia, James Baulderstone, wants the company to sell down to around a 50% interest in Narrabri and now expects the first gas production to come closer to 2020, rather than 2016-2017, as had been a previous target.

APPEA

15 JAN: APPEA advised that its CEO David Byers would leave in March to take up a position at BHP Billiton. The industry body has started a process to find a replacement Chief Executive.

EXPLORATION AND APPRAISAL

AGL Energy

27 JAN: AGL Energy advised that it had voluntarily suspended operations at its Waukivory Pilot in the Gloucester Basin after detecting BTEX chemicals in four water samples. AGL fracced the four wells at the pilot but did not use any BTEX chemicals, which are banned in NSW for that use. The company believes that the BTEX detected is most likely naturally occurring in the Gloucester Basin coals and will now review the water test results. Following AGL's notification of the chemicals detection at Waukivory the NSW EPA and Energy Ministry formally suspended operations at the pilot. AGL will not be able to resume testing at Waukivory until investigations by the government bodies have been completed.

RESERVES AND RESOURCES

Blue Energy

20 JAN: Blue Energy reported an increase in contingent resources at ATP 814 in the Bowen Basin. 2C resources across the four separate areas of the tenement were up from 722 PJ to 968 PJ with 3C resources increasing from 2,805 PJ to 3,453 PJ. The company has not undertaken any recent exploration activity within the acreage with the increases the result of data from Arrow Energy's surrounding Moranbah Gas Project. Blue aims to secure access to Arrow's proposed Bowen Pipeline from Moranbah to Gladstone, allowing ATP 814 to be developed to supply the Gladstone gas market. At the end of December 2014 Blue has some $6.8m of cash on hand with the company's yearly administration costs running at around $2m.

LNG

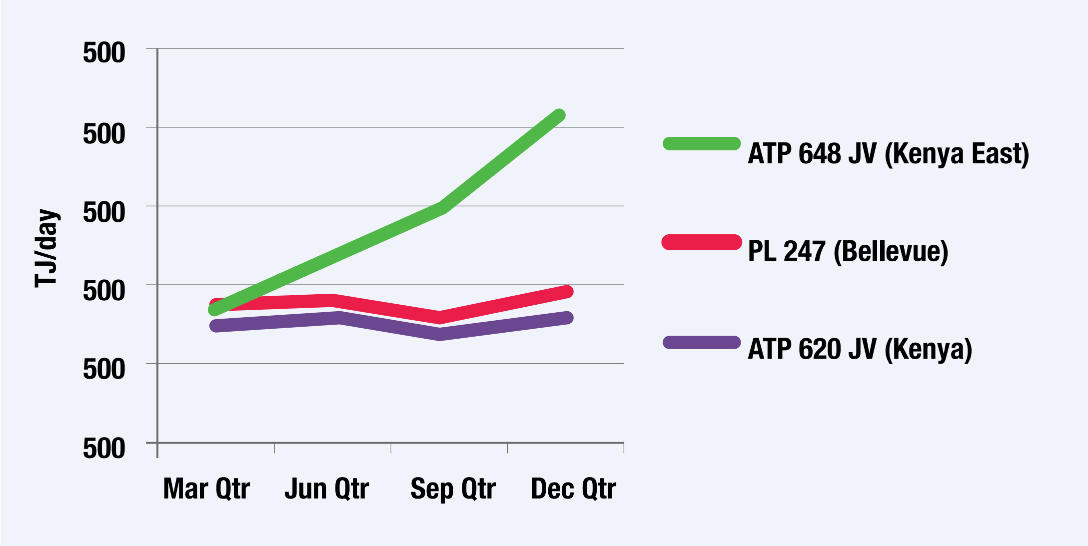
APLNG

30 JAN: Origin Energy advised that the APLNG project was 88% complete and due to deliver its first LNG in mid 2015. At the end of 2014 Origin as APLNG upstream operator had drilled a total of 1,019 development wells for the project with 455 of them having been drilled in that year. Of the total wells 666 had been commissioned, 575 of them in 2014. Additionally, a further 286 wells in APLNG acreage are being operated purely for the domestic gas market.

QGC

30 JAN: Figures released by Origin Energy showed how QGC ramped up production from the Kenya East CSG in 2014 to meet the start-up requirements for QCLNG Train 1. The field only started gas sales in May but produced at an average rate of 219 TJ/day during the December Quarter. During that Quarter the Kenya CSG fields, Kenya, Kenya East and Bellevue, together produced a total of 406 TJ/day, a rate of around 150 PJ/year.

2014 Kenya Average Daily Production



Arrow LNG

29 JAN: Shell revealed that plans to construct the Arrow LNG Plant had been officially cancelled. Shell and PetroChina acquired Arrow Energy in 2010 and proposed to develop an up to 18 MTPA LNG project on Curtis Island. An FID was originally scheduled for 2012 but was repeatedly delayed as Australian cost inflation affected project economics. Shell's announcement has now finally killed off the export project.

Arrow's Bowen and Surat Basin reserves will now be available to feed or even underpin the expansion of one or more of the three Curtis Island LNG plants currently being completed, easing the threat of any gas supply shortfalls. Development plans for extensive Bowen and Surat field developments and pipelines linking each of the projects with Gladstone have been approved and remain in place. However, after spending $3.5b on the Arrow acquisition and further significant funds on design and approvals Shell and PetroChina will look to take advantage of higher Eastern Australian gas prices in before they proceed with any developments.

GLNG

23 JAN: Santos reported that GLNG was on track to produce its first LNG in the second half of 2015. The 7.8 MTPA project is more than 90% complete with the first gas turbine generator at the liquefaction plant expected to be fired up for the first time in the next few weeks. Santos drilled a total of 119 wells in GLNG upstream acreage in 2014, comprising 86 development wells and 33 appraisal wells. During the year 153 wells were completed and 307 connected with 358 wells on-line at the end of the year, comprising 252 Fairview wells with an average production capacity of 2 TJ/day and 106 Roma wells, where dewatering continues and average well production of 0.5 TJ/day is expected. GLNG's gas transmission pipeline linking the project's upstream fields to Curtis Island has been completed and commissioned, with the first gas from Fairview entering the pipeline last October. At the LNG facility site all 111 pre-fabricated plant modules are in place and commissioning of some systems is underway. Both LNG storage tanks have been pressure tested and the LNG load-out jetty has been completed. Santos expects the second train of GLNG to be ready for start-up at the end of 2015 with the project to reach this milestone within its revised budget of US$18.5b at an estimated A$S/US$ exchange rate of $0.87 over 2011-2015.

INTERNATIONAL PRICES INTERNATIONAL INVESTMENT

Development of the Curtis Island LNG precinct has seen the linking of eastern Australian gas prices to Asian LNG markets. The large amounts of capital required to develop the LNG projects came from international oil and gas majors including BG Group, Petronas, ConocoPhillips, Shell, PetroChina, Total and CNOOC. At the same time as the LNG projects were being developed rising interest in the prospects of shale gas exploration led to further international investment in Australian plays. This led to funds for initial assessment of many of Australia's relatively expensive frontier plays coming from overseas and tie-ups between large companies and Australian juniors. With the oil price crash leading to large capital expenditure cuts by these same companies the medium term prospects of some Australian unconventional plays will now be decided in boardrooms in the U.S. and Europe where their relative size and importance may not even justify a separate line entry in a multi-billion dollar CapEx budget. The staged nature of most of the deals agreed also makes withdrawal relatively easy. With results from the December Quarter now in, the first effects of the oil price drop on oil company finances have been reported, and some of the first CapEx budget cuts for 2015 have been revealed. The first and perhaps most important indicator of continuing international investment in Australian unconventional plays will come when Chevron reveals its intentions for its farm-in to Beach Energy's Nappamerri Trough acreage.

Beach is nearing the end of operations for the first stage of the farm-in. This first stage saw the U.S. company pay Beach a total of US$95m and carry a further US$95m of expenditure in order to earn a 30% interest in PEL 218 and 18% in ATP 855. Results of the extensive exploration program undertaken by Beach have been mixed with some good gas flows as well as disappointing flows and some technical problems, to be expected in pioneering a new exploration play at great depths and high temperatures and pressures. What Beach has shown is that there is a lot of gas in the play, in multiple formations, and that it can be brought to surface. To determine whether it can be developed economically however, will take further sustained investment. Chevron is due to decide on proceeding with the second stage of the farm-in by the end of March. This would require an upfront payment of US$77m and a further US$47m carry to earn a further 30% and 18% interest in PEL 218 and ATP 855, respectively.

On the 30th of January Chevron announced a 2015 CapEx budget down 13% from 2014's spend. Although much of the decline is related to lower required investment at development projects like Gorgon and Wheatstone the company also cut planned exploration investment. Capital allocated to exploration and pre-FID projects, the segment likely to cover the Napamerri, was significantly reduced. These projects will also be high-graded and paced, which will likely see detailed scrutiny of further investment in the Australian unconventional play.

Beach announced modest cuts to its FY2015 exploration spend during January, with a planned reduction in development and exploration CapEx from $450m-$500m to $430m-$470m. With $50m of a planned $50m-$55m in unconventional exploration already spent in the first half of the financial year total unconventional spend is actually forecast to be higher for the full year at $55m-$60m. Any further Nappamerri investment as the project moves to the appraisal stage with the first pilot wells will start in the next financial year. Beach has repeatedly expressed its confidence in the project and is likely to continue investment even if Chevron elects not to participate. With the decision to be known in just two months it will provide a very public affirmation or otherwise on the prospects of the various Nappamerri plays. There is also the possibility that the two companies will revise the original farm-in agreement to provide a more staged investment or better terms for Chevron. The decision will also have a profound impact on the junior Icon Energy, with its 35% stake in ATP 855 being its major asset. Funding its share of ongoing exploration will be much more difficult if Chevron chooses not to be involved. The Nappamerri decision will be the first major indication of whether declining oil prices will lead to major declines in Australian unconventional investment.

EXPLORATION AND APPRAISAL

Strike Energy

29 JAN: Strike Energy reported further positive results from its Southern Cooper Basin Gas Project. Flow testing at the deep CSG field showed gas saturation of 90% at the Le Chiffre-1 well and 60% at Klebb-1. Formation water and gas is continuing to flow from both wells with sufficient gas being produced from Le Chiffre-1 to require flaring. The well, which was fracced prior to testing commencing, produced 32,500 bbls of water over 31 days while Klebb-2, which was perforated but not fracced produced 12,000 bbls of water over 45 days. Strike will bring two further perforated wells at the project onto test and has commenced plans for a multi-well pilot at Le Chiffre.

Drillsearch Energy

28 JAN: Drillsearch Energy announced that it had completed the Nappamerri Trough well, Amidala-1, in ATP 940. The well took 57 days to drill to a total depth of 3,488 m, and will be fracced in the future. Amidala-1 was the fourth and final well drilled in the program with two of the wells already fracced. The first, Charal-1, was brought on-line for production testing at the end of December after thirteen stages were placed in the Roseneath, Epsilon, Murteree and Patchawarra Formations. A peak flow of 0.95 MMscfd through a 30/64” choke with a wellhead pressure of 629 psi was recorded from the well on January 1st. Some two thirds of the gas flow was from the Patchawarra and carbon dioxide content in the range of 20%-30% was recorded. QGC has a 60% interest in ATP 940 after a farm-in to the tenement.

Senex Energy

21 JAN: Senex Energy advised that it would acquire some 300 km^2 of 3D seismic in the Cooper Basin during the first half of 2015. The program will be funded by Origin Energy, under a farm-in targeting the tight gas potential of the Patchawarra and Allunga Troughs. The first stage of the agreement will see Origin fully fund $105m of expenditure, with the first well to be drilled in the Allunga Trough in mid 2015. With Senex reducing its total FY2015 capital expenditure budget from $100m-$125m to $85m-$90m as a result of the oil price slide the Origin farm-in ensures that exploration of these unconventional targets is unaffected.

Transerv Energy

21 JAN: Transerv Energy advised that it had contracted a rig to drill two wells at the Warro tight gas field in the Perth Basin around the middle of this year. The wells will be fracced and tested with the program to be funded by JV partner Alcoa.

Beach Energy

20 JAN: Beach Energy reported further results from its current Nappamerri Trough appraisal program. In ATP 855 the Geoffrey-1 well flowed at a peak rate of 1.1 MMscfd on a 12/64” choke with wellhead pressure of 3,058 psi, gas produced was 75% methane and 25% carbon dioxide. The test came after clean-up of a five stage fracc with four Patchawarra Formation intervals and one Epsilon Formation interval. Redland-1 was subject to a three-stage fracc in the Toolachee Formation however mechanical issues prevented testing and the well was shut-in. In PEL 218 in the SA section of the trough the Boston-2 well will be fracced over eight stages, testing of the well will conclude the current appraisal program and the first stage of Chevron’s farm-in to Beach’s Nappamerri acreage.

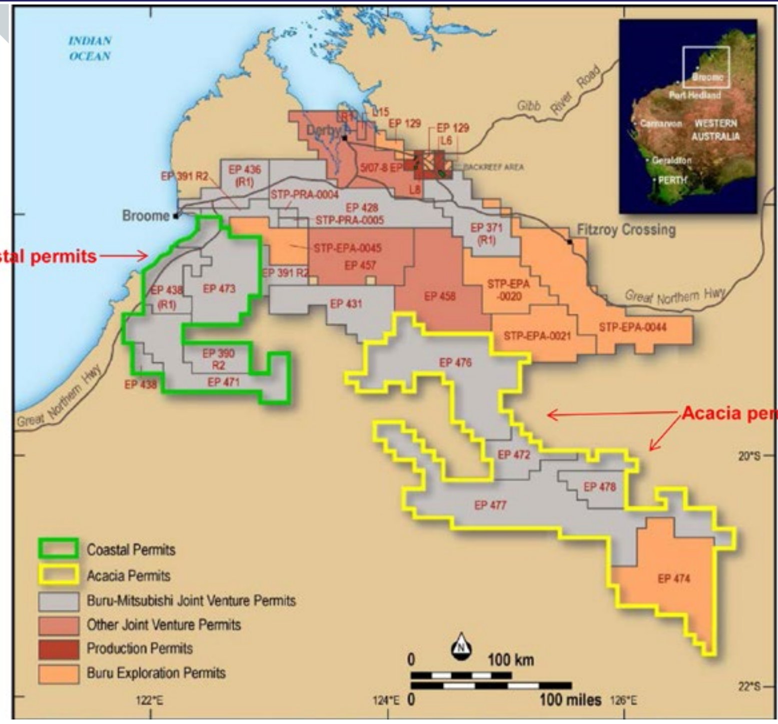
ACREAGE

Buru Energy

30 JAN: Buru Energy reported that Apache Energy had allowed an option to farm-in to five Canning Basin tenements to lapse. The ‘Acacia Permits’ are located in the south eastern section of the basin and are considered prospective for the Goldwyer shale play, with Apache having paid at least $7.2m for the farm-in option, agreed in November 2013. Buru recently relinquished one of the tenements, EP 474, due to its remoteness and high operating costs. Apache is still committed to a $25m farm-in to earn a 50% interest in four ‘Coastal Permits’ held by Buru and JV partner Mitsubishi. The company drilled the dry oil well Commodre-1 in EP 390 in December as part of this agreement.

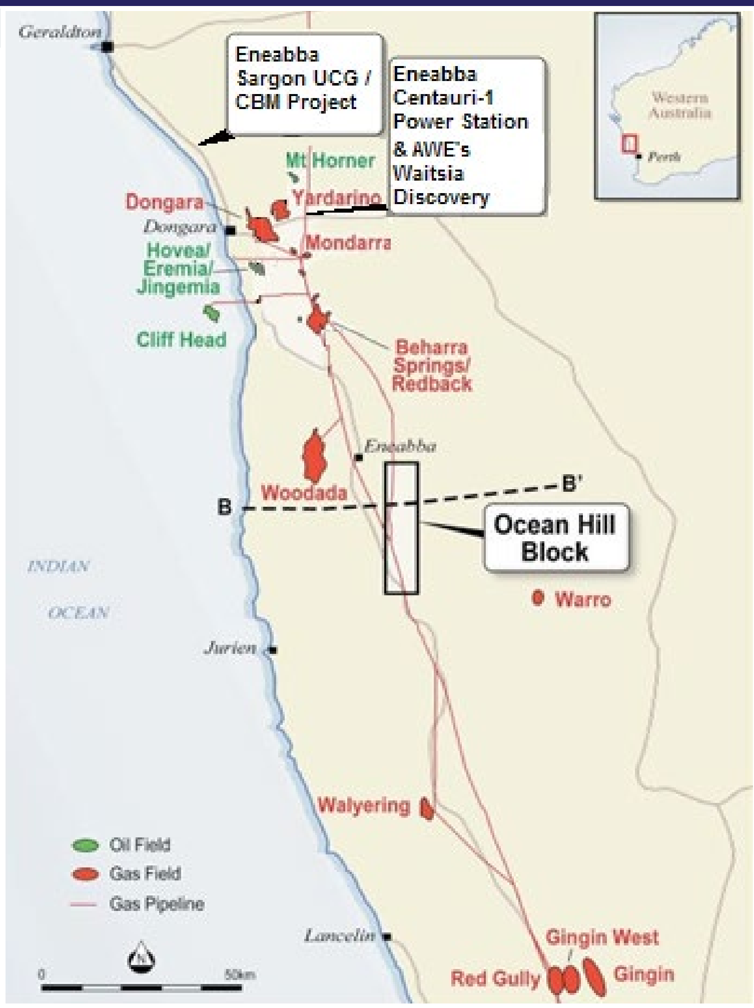
Earlier, on the 2nd of January, Buru advised that its agreement to buy a 50% interest in the Canning Basin tenement EP 487 from Backreef Oil for $3.5m had expired. The interest is currently the subject of a WA State Administrative Tribunal action with Oil Basins applying to claim Backreef’s stake and take 100% ownership of the tenement; a judgement is expected in February. If the judgement is in Backreef’s favour it will then sell the interest to Rey Resources for either $2m, to be paid when a production licence is granted over EP 487, or a 2% production royalty, with the choice to be at Rey’s election. EP 487, known as the Derby Block, has an area of some 5,000 km^2 and is located within the Canning’s Laurel tight gas province.

Canning Basin – Apache farm-in



Source: Buru Energy

Ocean Hill Block



Source: Eneabba Gas

Finder Exploration

27 JAN: Eneabba Gas announced that Finder Exploration would farm-in to its north Perth Basin block STP EPA 0090. Privately held Finder will become operator of the tenement and fund an up to $15m work program over two years to earn an 85% interest. This will include drilling an offset well to Ocean Hill-1, which was drilled in 1991 and discovered gas in the Jurassic Cattamarra Coal Measures and the Cadda Formation, and acquiring 250 km^2 of 3D seismic. Drilled to a total depth of 3,840 m Ocean Hill-1 had gas shows overn an 800 m interval and a drill stem test recorded gas flows of up to 0.7 MMcfd with 15-23 bbl/MMcf of condensate. During 2013 DeGolyer & McNaughton estimated a 2C contingent resource of 360 bcf for the Ocean Hill structure. Finder has previously focussed on offshore WA and is a 20% owner of the recent Phoenix South-1 oil discovery.

Armour Energy

15 JAN: Armour Energy advised that the Queensland Department of Natural Resources and Mines has awarded the company preferred tenderer status for two new tenements, both located in the South Nicholson Basin. The tenements cover an area of 5,400 km^2 and extend the company's position in the Lawn and Riversleigh shale plays. The accepted work programs for the permits are likely to include seismic acquisition in the second year and the drilling of one or more wells in the fourth year. Armour will now need to negotiate Native Title agreements before the tenements can be granted.

On the 14th of January Armour reported that it had successfully appealed an Ausindustry decision not to grant the company an R&D rebate, it can now expect to receive the several million dollars rebate in the next few months. The cash refund comes at an opportune time for Armour, at the end of 2014 it had cash on hand of just $1.5m.

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								
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	
Total for Arrow Energy				**160**	**2,512**	**5,350**	**90**	
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								
Western Surat Project	Senex Energy* 100% - 45%	Qld	Surat		488			ATPs 767, 795, 889, 593, 791
Total for Senex Energy including projects operated by others					**488**			

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

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 50% Train 1 and 97.5% Train 2 / CNOOC 50% 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:	First LNG from Train 1 Dec 2014, Train 2 to follow in 2015	**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* 100%	Qld	Surat				
Lawton	BG* 100%	Qld	Surat				