ENERGYQUEST

Oil and Gas Industry Cost Trends

An independent report prepared by EnergyQuest for the Australian Petroleum Production & Exploration Association

1 November 2014

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Key Points

- Petroleum industry costs have been increasing globally since 2000. Finding and development costs (F&DC) for new reserves increased six-fold between 2000 and 2013, from less than US$5/barrel of oil equivalent (boe) to over US$25/boe.
- According to IHS CERA, global upstream capital costs have more than doubled since 2000 and operating costs have nearly doubled. (The even greater increase in F&DC implies that reserve additions per dollar spent on development have also fallen.)
- There have also been significant increases in Australia. In the three years to 2013 total Australian F&DC averaged $4.16/GJ, 2.7-times the average for the three years to 2007.
- The average cost of Australian and PNG LNG projects (including both upstream costs and LNG plant development) increased by 33% between 2009 and 2013, reflecting both higher upstream and plant construction costs.
- Costs have increased substantially for development of offshore domestic gas projects. A decade ago offshore domestic gas projects could be developed for less than A$1.00/GJ of 2P reserves. Costs are now up to A$3.00/GJ, a three-fold increase. The increase reflects higher costs for drilling rigs, labour and materials, such as steel, and also lower field size and quality (requiring more treatment).
- F&DC in Queensland have increased from an average of A$0.83/GJ in the three years to 2011 to A$5.37/GJ in the three years to 2013, a 6.5-fold increase. Costs were low when companies were mostly in the exploration phase but have jumped significantly with LNG development underway.
- Santos eastern Australia F&DC (excluding GLNG) have increased from A$1.76/GJ in the three years to 2011 to A$3.15/GJ in the three years to 2013, almost a two-fold increase. If Santos is unable to develop its NSW reserves its F&DC will increase to A$4.21/GJ to 2011 and A$5.88/GJ to 2013.
- Anecdotal evidence is that current infill drilling for gas in the Cooper Basin is marginal economically, even at current higher gas prices. Current development costs to increase production capacity are estimated at around $5/GJ, to which has to be added operating costs, taxes and royalties and a profit margin.
- Higher exploration costs are an important driver of higher F&DC. A decade ago the average exploration cost in the Cooper Basin was $2-3m per well. It has since doubled, notwithstanding more efficient drilling practices. The average exploration cost in Queensland (reflecting both conventional and CSG targets) has increased from less than $1.0m per well in 2008 to almost $3.0m in 2013. Offshore Western Australia there has been a steep increase in costs over the last decade from $10m per well to $90m. This reflects higher rig rates and more challenging drilling.
- The overall cost of the Turrum-Tuna-Kipper project in Bass Strait, including the gas conditioning plant, is approximately $5.6 billion to develop 400 MMboe of oil and gas, with a development cost of $14/MMboe or $2.45/GJ, notwithstanding that the development will only maintain, not increase production through the existing Longford plant.

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- The best oil and gas fields are developed first and development then moves to higher cost fields if commercially viable. Based on AGL's estimate of the east coast gas cost curve (breakeven prices), the large bulk of east coast resources are estimated to have a break-even price of over $5/GJ, increasing to over $9/GJ.
- There have been significant increases in the cost of materials. The price of Hot Rolled Coil steel ex-Asia, used for tubulars and gas transmission pipelines, increased through the 2000s and peaked in 2011 at over US$700/tonne. Prices have since declined (in US$ terms) to around US$500/t but they are still significantly higher than during the 2000s.
- High Australian labour costs are one of the drivers of higher costs. Incitec has said that it will cost around $1 billion to build its new ammonia plant in the US compared with $1.4 billion in Australia. Labour costs would be 35% of the total project in the US compared with 60% in Australia. Bechtel has quoted earnings of $3,000 per week for special class welders, the equivalent of $156,000. SEEK reported that annual salaries for oil and gas exploration jobs increased by 13% in 2013 to $158,671.The Hays Oil and Gas Salary Survey for 2013 found average Australian oil and gas salaries for permanent staff of US$163,700 pa, the second highest in the survey after Norway. Higher costs reflect not only wages but also poor productivity.
- Tighter environmental regulation has increased costs. A decade ago water produced with CSG in Queensland could be evaporated. It now generally requires reverse osmosis. A decade ago gas producers were not expected to pay material amounts in compensation to land owners. This has now changed. Producers are also expected to make community contributions, which have totalled $127.5m in Queensland to the end of 2013.
- Supply restrictions mean that potentially low-cost gas cannot be accessed. Gunnedah and Gloucester gas may be some of the lowest-cost gas on the east coast.

Terms of Reference

APPEA has asked EnergyQuest to undertake an assessment of the degree to which oil and gas exploration and development costs have increased in recent years and what have been the main drivers.

Concepts

The petroleum industry typically measures costs in terms of finding and development costs (F&DC) expressed as dollars per barrel of oil equivalent (boe).

F&DC are measured as the total of exploration costs in a year plus expenditure on developing discovered fields, divided by gross additions of reserves in that year (measured as boe). Internationally the denominator is Proved reserves (1P) but in calculating Australian costs we need to use Proved and Probable reserves (2P), which is the Australian reporting standard.

Using boe as the denominator is a means of combining discoveries of oil, gas and natural gas liquids (LPG and condensate) on an equivalent energy basis. This is relevant for conventional gas discoveries, which may also be associated with oil and liquids. Coal Seam Gas (CSG) is dry, without oil or liquids so F&DC for CSG reflects solely gas costs.

Because Australia is more gas than oil-prone and because of the interest in gas we have converted boe to gigajoules (GJ) at 1 boe equals 5.8 GJ.

F&DC should not be confused with break-even production prices. F&DC do not include operating costs, royalties and taxes or take account of the time value of money. Break-even production prices are generally at least twice F&DC for a development.

Spending on exploration and development is typically lumpy from year-to-year at the company level and even at the country level. Reserves are typically booked at the time of Final Investment Decision (FID), followed by development expenditure, so F&DC may appear abnormally low at FID and then increase afterwards as money is spent on development. Reserve additions are also lumpy and it is quite possible to get a fall in reserves, notwithstanding spending on exploration and development (i.e. a negative F&DC). To overcome the lumpy nature of expenditure and reserve additions, F&DC are typically also expressed as a rolling three-year average.

Estimates of F&DC for different companies and jurisdictions are not necessarily comparable, particularly given the lumpy nature of development and differences in accounting treatments. The focus of this report is on trends over time, rather than differences between companies and/or regions.

Drivers of costs

Oil and gas is a global industry and costs reflect global as well as local developments. There is a global pool of professional labour and development and operating costs reflect prices charged by global oil services companies and the cost of imported materials. Although oil and gas supply different markets and prices in energy terms differ, they rely on the same pool of professional labour and other services. Fluctuations in exchange rates, especially the A$/US$ also affect costs.

Costs can be driven by cyclical and structural factors. Cyclical costs vary with the oil price, pace of development and the economic cycle. Structural costs reflect long-run trends such as deterioration in asset quality over time.

There is no comprehensive and detailed time series of Australian oil and gas industry costs, let alone one that breaks down costs into various components. However it is possible to deduce general trends.

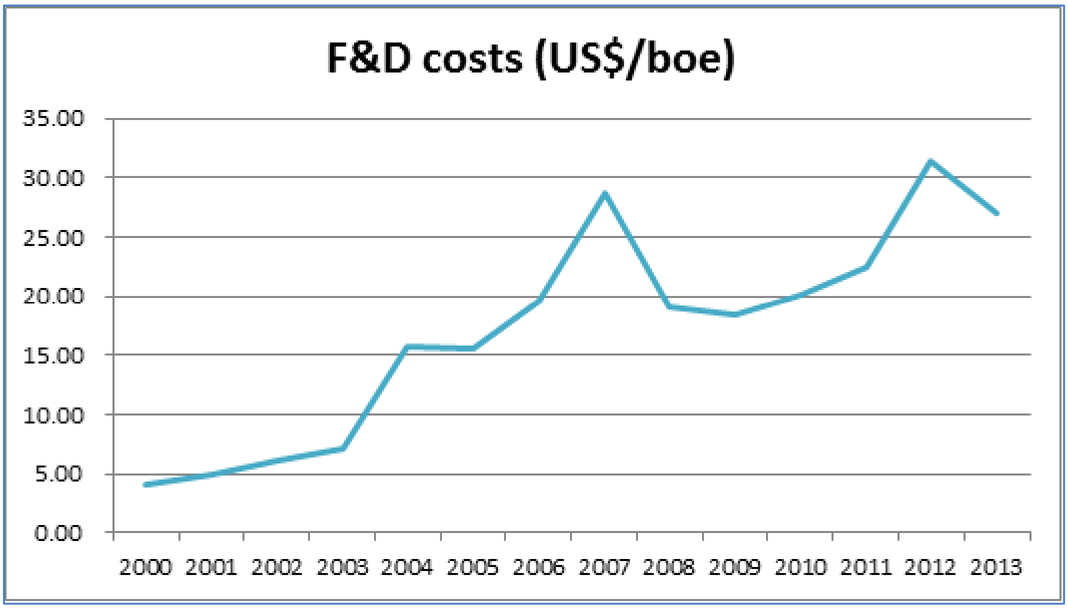
Global cost trends

The Australian industry operates in a global cost environment. Figure 1 shows trends in global F&DC, based on Proved reserves in US$/boe. Globally F&DC have increased six-fold since 2000. Costs peaked in 2007, fell by one-third with the Global Financial Crisis and then increased again.

Figure 2 shows indexes of global capital and operating costs in the industry. Globally upstream capital costs have more than doubled and operating costs have nearly doubled since 2000. The growth in costs follows a similar pattern to the increase in oil prices over the same period. While the increase in capital and operating costs is not as great as that in oil prices it does follow a similar pattern except that the fall in oil prices in 2008 and 2009 only moderated the growth in capital and operating costs.

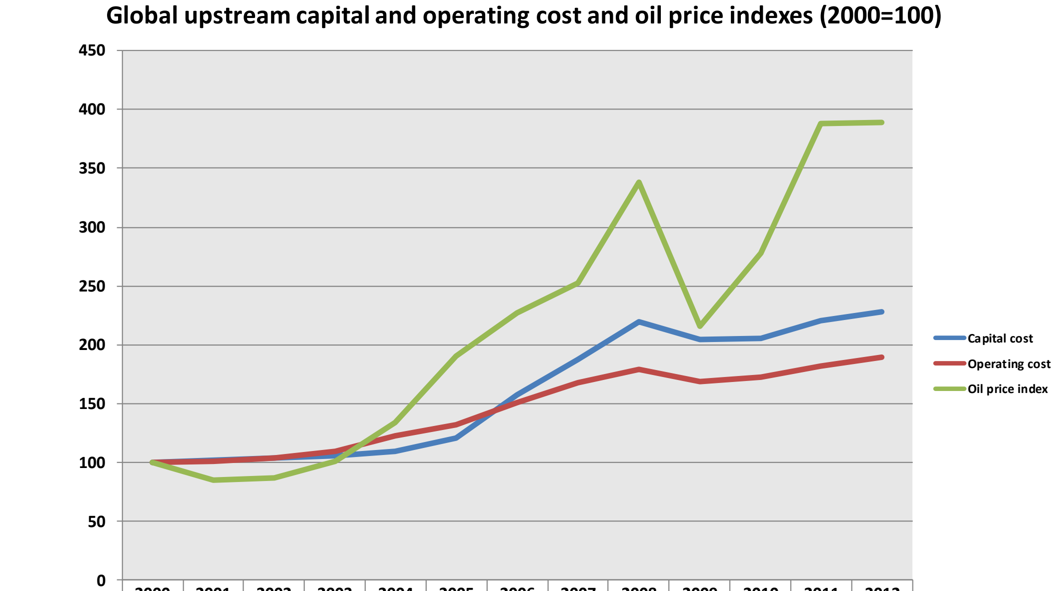
While capital costs have more than doubled, F&DC have increased even more. This is because F&DC metrics also capture declining resource quality.

Figure 1 Global F&D costs (US$/boe)



Source: Credit Suisse

Figure 2 Global upstream capital and operating cost and oil price indexes (2000=100)



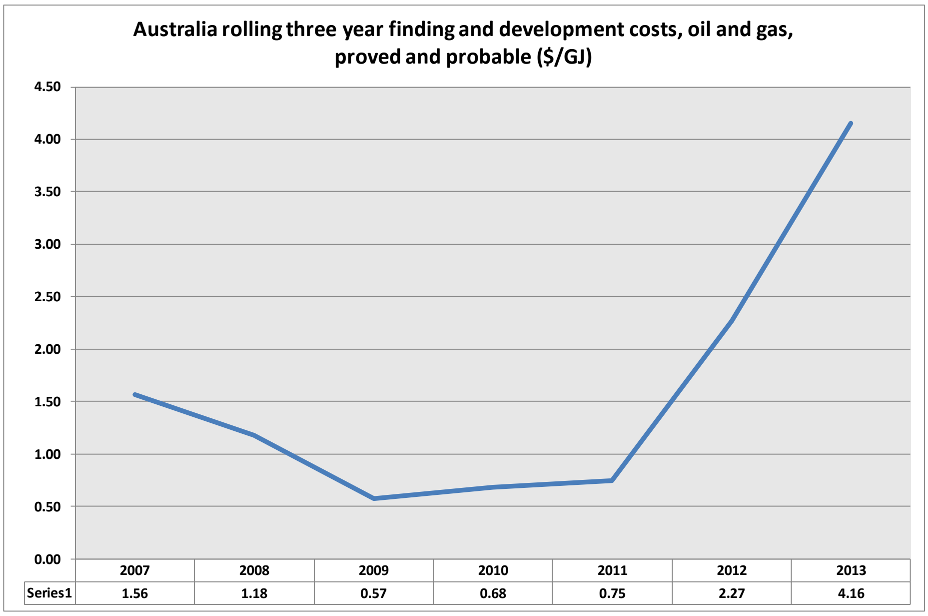
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Capital cost	100	102	104	106	109	120	157	188	220	205	206	220	228
Operating cost	100	101	103	110	123	132	151	168	179	169	173	182	189
Oil price index	100	85	87	101	133	190	227	253	338	215	278	388	389

Sources: IHS CERA, EIA

Australian costs

Figure 3 shows rolling three year F&DC for Australia, expressed as A$/GJ, based on ABS data on expenditure on oil and gas exploration and development and EnergyQuest estimates of Australian 2P reserves. The rolling 3-year F&DC to 2013 is 5.6 times higher than that in the three years to 2011. The increase reflects the heavy spending on (and cost of) upstream field and LNG plant development.

Figure 3 Australia rolling three year finding and development costs, oil and gas, proved and probable (A$/GJ)

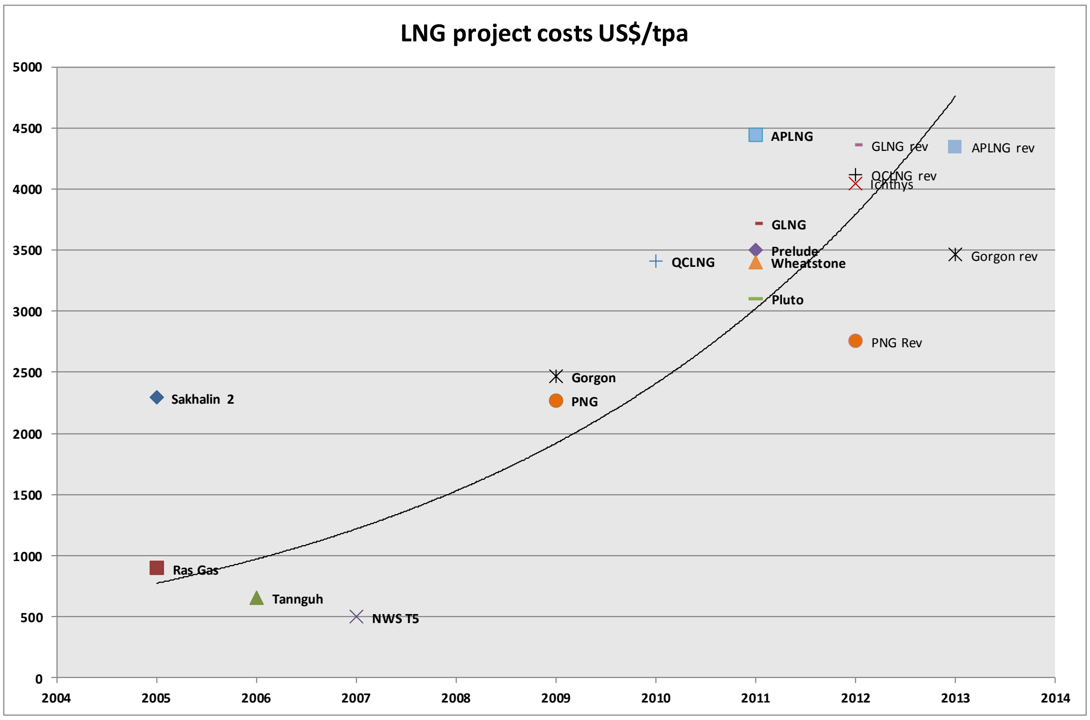


Source: ABS, EnergyQuest

LNG development costs

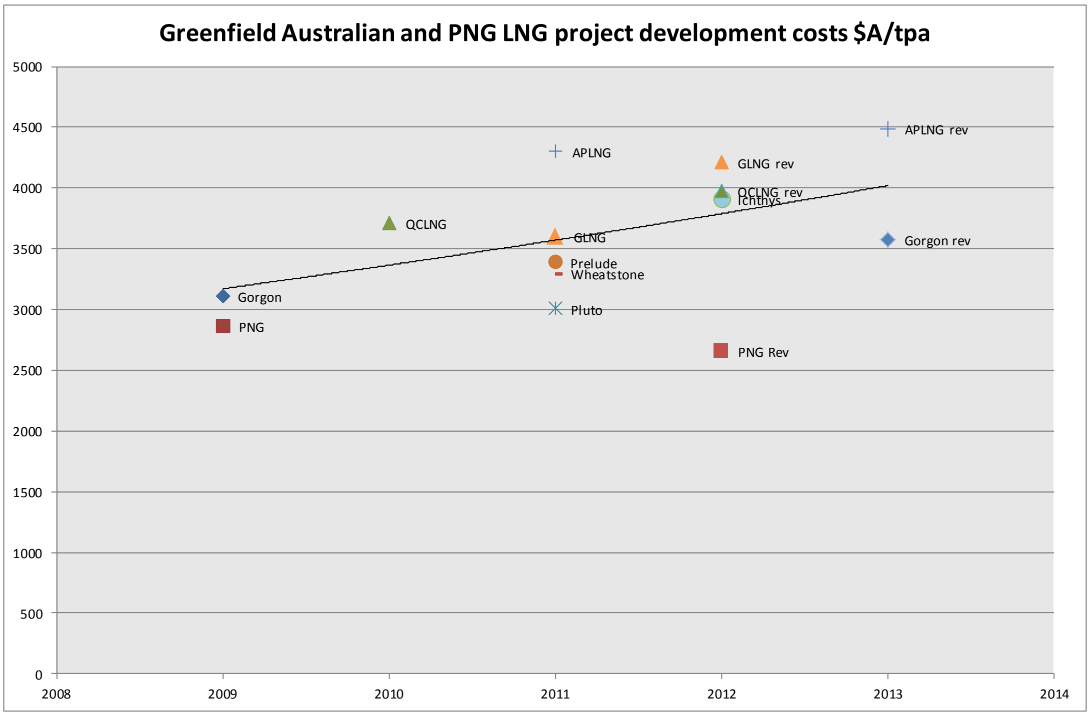
Figure 4 shows LNG project development costs, expressed as US$ per tonne per annum of capacity (tpa). The pre-2008 data points are for projects completed in those years in Australia (NWS Train 5, a brownfield project), Russia (Sakhalin), Indonesia (Tangguh) and Qatar (Ras Gas). The subsequent data points are for new Australian and PNG projects. Pluto and PNG are now in production but the other projects are still under construction and the data points show the timing of cost announcements, both original and revised ("rev"). Company cost estimates for the CSG LNG projects are only to first LNG so we have had to estimate costs post-first LNG (mostly based on company guidance). The estimates all include upstream costs (typically two-thirds to three-quarters of total cost) plus LNG plant costs. LNG development costs in Australia are nearly twice as high in US$ terms than a decade ago, reflecting higher costs for both upstream development and LNG plant construction.

Figure 4 LNG project costs (US$/tpa)



Source: EnergyQuest

Figure 5 Greenfield Australian and PNG LNG project development costs (A$/tpa)



Source: EnergyQuest

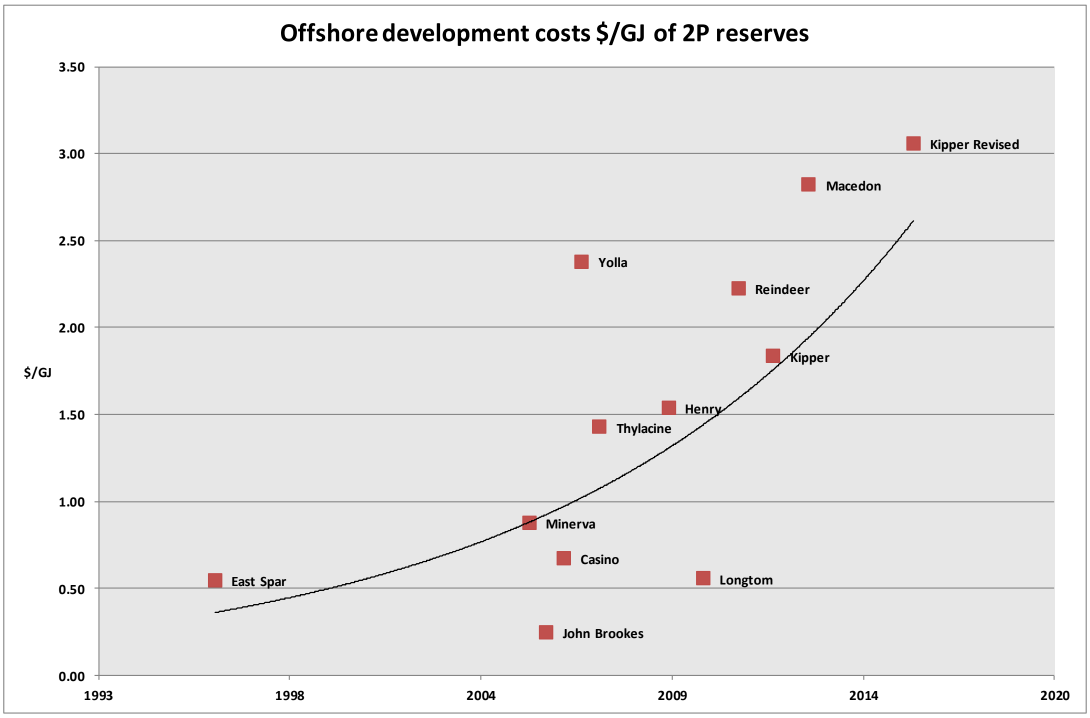
Costs in US$ are the focus for companies making investment decisions and this is affected by currency fluctuations, primarily the appreciation of the A$ in the case of Australian LNG projects. Figure 5 also shows data points for Australian and PNG LNG projects in A$/tpa. Comparing the same projects between 2009 and 2013, the cost increase in A$ is approximately 33%.

Offshore domestic F&DC

Figure 6 shows development costs for offshore domestic gas projects in A$/GJ of 2P reserves by date of first production. A decade ago offshore domestic gas projects could be developed for less than A$1.00/GJ of 2P reserves. Costs are now up to A$3.00/GJ, a three-fold increase. Offshore Western Australia, the John Brookes field, which came into production in 2005, cost $300m to develop 1,200 PJ of 2P reserves ($0.25/GJ). The Macedon field, which came into production in 2013, cost $1,600 to develop 570 PJ of 2P reserves (2.82/GJ), a more than 11-fold increase in development cost per unit of reserves. Development of the Greater Western Flank for the North West Shelf (LNG and domestic gas) now costs A$2.10/GJ compared with the cost of developing the North Rankin field, which was A$0.95/GJ.

One driver of higher costs is lower field quality. Development of the Macedon gas field required a broadening of the Western Australian gas specification. New developments offshore Gippsland are prone to mercury and CO_2, which require treatment, adding to development costs. Fields are also less likely to contain higher-priced oil, condensate or LPG. If the Sole field is to be developed offshore Gippsland it will be necessary to treat H_2S.

Figure 6 Offshore domestic gas development costs A$/GJ of 2P reserves

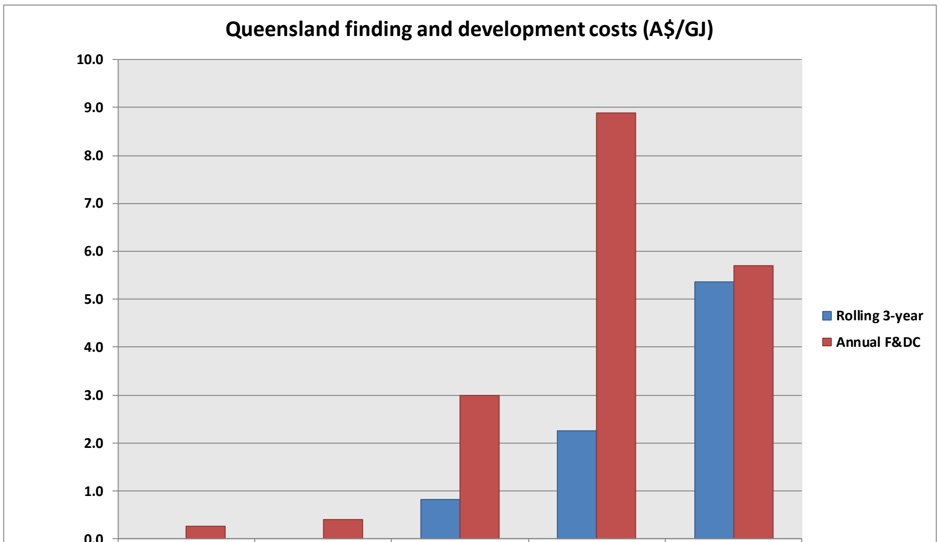


Source: EnergyQuest

Queensland F&DC

Figure 7 shows Queensland F&DC, including CSG and the Queensland sector of the Cooper Basin. F&DC have increased from an average of A$0.83/GJ in the three years to 2011 to A$5.37/GJ in the three years to 2013, a 6.5-fold increase. Costs were low when companies were mostly in the exploration phase but have jumped significantly with development underway.

Figure 7 Queensland finding and development costs (A$/GJ)



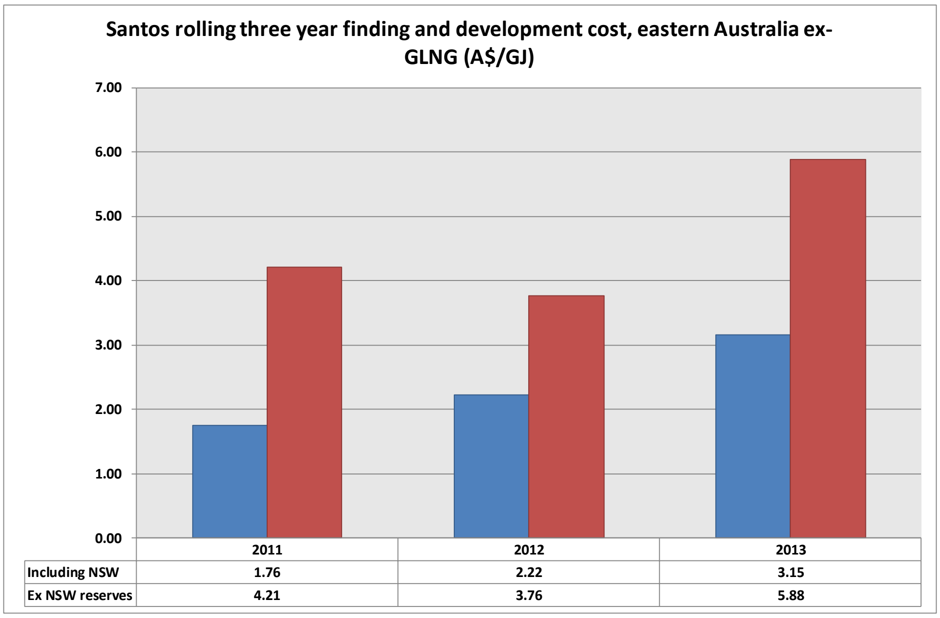
	2009	2010	2011	2012	2013
Rolling 3-year			0.83	2.26	5.37
Annual F&DC	0.26	0.41	3.00	8.88	5.70

Source: ABS, Qld DNRM

Eastern Australia F&DC

Santos discloses exploration and development expenditure for Eastern Australia (defined as Queensland excluding GLNG, South Australia, NSW, Victoria and Central Australia). This makes it possible to calculate F&DC excluding east coast LNG. F&DC have increased from A$1.76/GJ in the three years to 2011 to A$3.15/GJ in the three years to 2013, almost a two-fold increase (Figure 8). If Santos is unable to develop its NSW reserves its F&DC will increase to A$4.21/GJ to 2011 and A$5.88/GJ to 2013.

Figure 8 Santos rolling three year finding and development cost, eastern Australia ex-GLNG (A$/GJ)



Source: Santos

Cost drivers

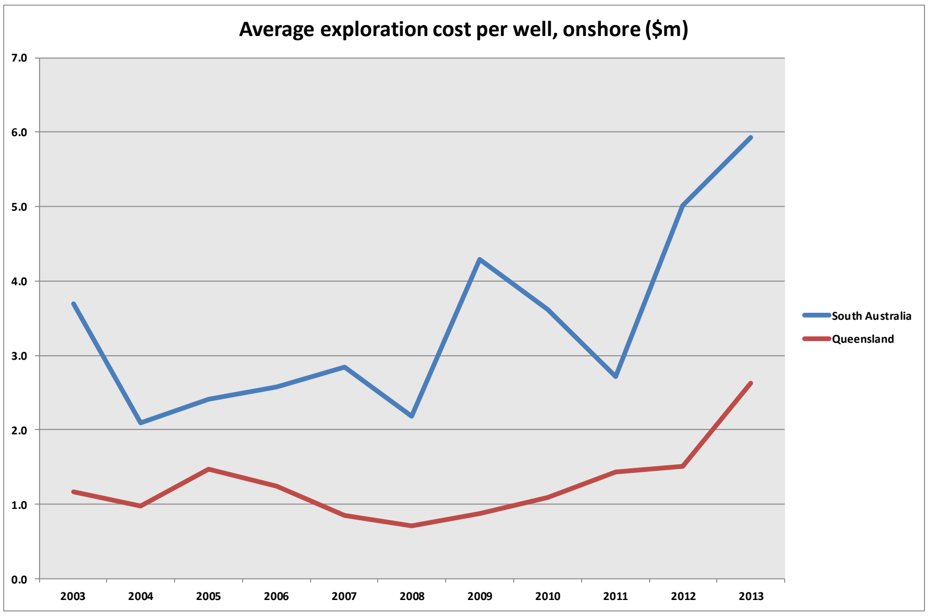
Exploration costs

Higher exploration costs are an important driver of higher F&DC. Figure 9 shows exploration expenditure in South Australia (mostly Cooper Basin) and Queensland divided by wildcat and appraisal exploration wells drilled. Exploration expenditure includes costs of seismic and drilling and associated costs. A decade ago the average exploration cost in the Cooper Basin was $2-3m per well. It has since doubled, notwithstanding more efficient drilling practices. If the average find is also smaller, the increase in finding costs is even greater.

The Queensland numbers are a mix of conventional Cooper Basin wells and CSG wells. The decline in average cost in 2007 and 2008 reflects the growing number of cheaper CSG wells, which dominate drilling from 2008. The average exploration cost has increased from less than $1.0m per well in 2008 to almost $3.0m in 2013.

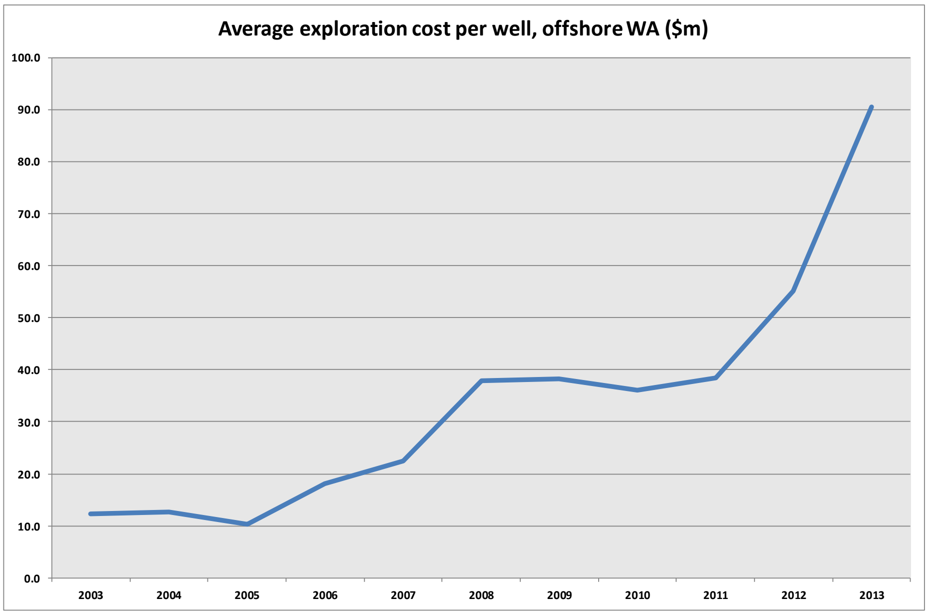
Figure 10 shows average exploration cost per well for offshore Western Australia. Over the last decade there has been a steep increase in costs from $10m per well to $90m. This reflects higher rig rates and more challenging drilling.

Figure 9 Average exploration cost per well, onshore ($m)



Sources: ABS, APPEA, Qld DNRM

Figure 10 Average exploration cost per well, offshore WA ($m)



Sources: ABS, APPEA

Field and plant investment

Cooper Basin

Santos is expanding the capacity of the Moomba gas plant from 430 TJ/d (Moomba and Ballera combined) to up to 600 TJ/d over 2014 to mid-2017 at a cost of up to $800 million gross.   This includes an extra 1 Mtpa CO_2 removal train. Plant reliability is also being improved. Total capital expenditure is expected to peak in 2016. Long term stay-in-business capex is expected to be ~$500m pa net to Santos, of which ~$100m is oil and ~$400m gas, to develop the 2P reserves. The company is working on reducing costs, targeting a 25% reduction in drilling costs by 2015.

The Cooper Basin has 1,800 PJ of conventional 2P reserves, 15 years reserve life at a production rate of 120 PJ/a. If stay-in-business capex is $600m gross pa ($400m net), that implies an average development cost of $5/GJ, to which has to be added operating costs, taxes and royalties and a profit margin. Anecdotal evidence is that current infill drilling is marginal economically, even at current higher gas prices.

Bass Strait

The $4.5 billion Kipper-Tuna-Turrum project commenced production in June 2013, with gas production from the Tuna field and oil production from Turrum. The project will help maintain (not increase) current Bass Strait production levels. The Tuna reservoir, which has been producing oil for many years, has been further developed to produce additional gas and associated liquids from the field. This has been done by converting existing West Tuna facilities, and also using new pipelines to deliver production into the existing gas system.

The Turrum field holds approximately 1 Tcf of gas and 110 MMbbl of oil and gas liquids. A new platform, Marlin B, has been constructed and linked by a bridge to the existing Marlin A platform. Gas associated with the production of oil from Turrum will be re-injected until the new US$1,040 Longford Gas Conditioning Plant comes on line in 2016.

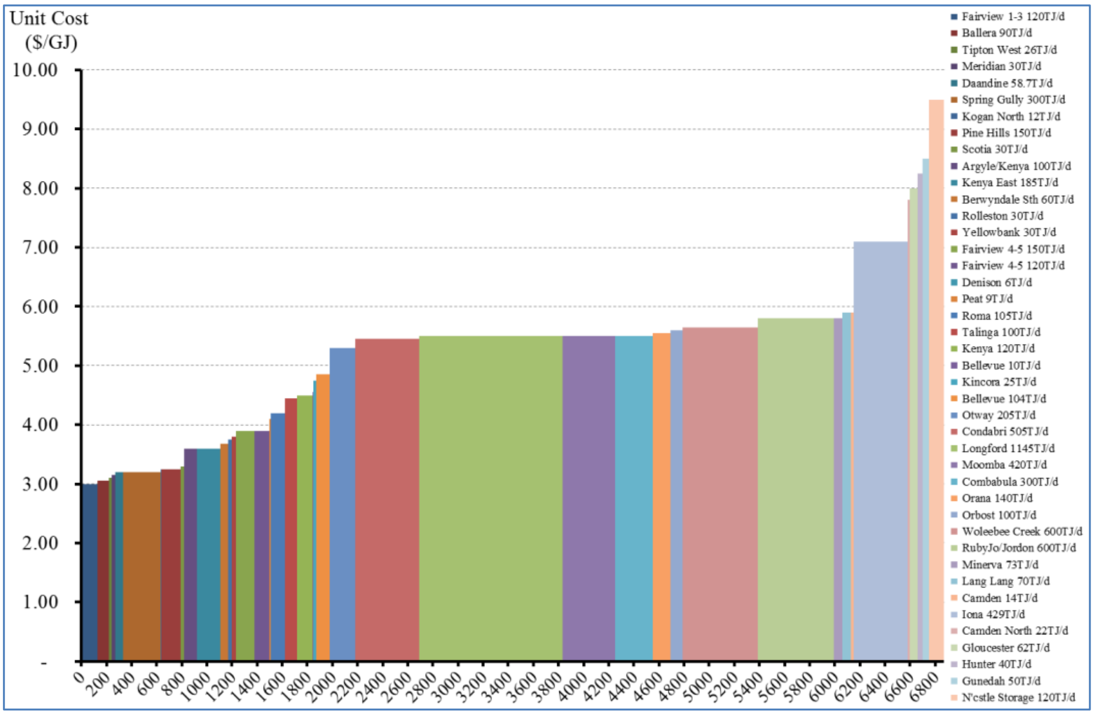
The Kipper field holds approximately 620 Bcf of recoverable gas and 30 MMbbl of condensate/LPG. It is located in 100 m of water, approximately 45 km off the Gippsland coast. Facilities for the Kipper field are complete and include subsea wells, coolers and a manifold. The produced gas and condensate will be transported via a new looped pipeline laid on the seabed to the existing West Tuna platform. Two new pipelines, one from West Tuna to Marlin and another from Marlin to Snapper have been installed for Kipper production and development of the Tuna gas cap. Development was sanctioned in December 2007. First gas from the field is delayed beyond the previous expectation of the first half of 2012 and is now expected in H1 2016 following the installation of mercury removal facilities.

The overall cost of the project is approximately $5.6 billion to develop 400 MMboe of oil and gas, with a development cost of $14/MMboe or $2.45/GJ, notwithstanding that the development will only maintain, not increase production through the existing Longford plant. We estimate that the break-even gas price for Kipper as a stand-alone development is $7.45/GJ due to the project delays and need for mercury treatment.

Deteriorating field quality

The best oil and gas fields are developed first and development then moves to higher cost fields if commercially viable. Figure 11 shows estimates of the east coast gas cost curve (breakeven prices). The large bulk of east coast resources are estimated to have a break-even price of over $5/GJ, increasing to over $9/GJ.

Figure 11 Aggregate gas supply for the east coast for 2018 ($/GJ)



Source: Simshauser and Nelson (2014)[1]

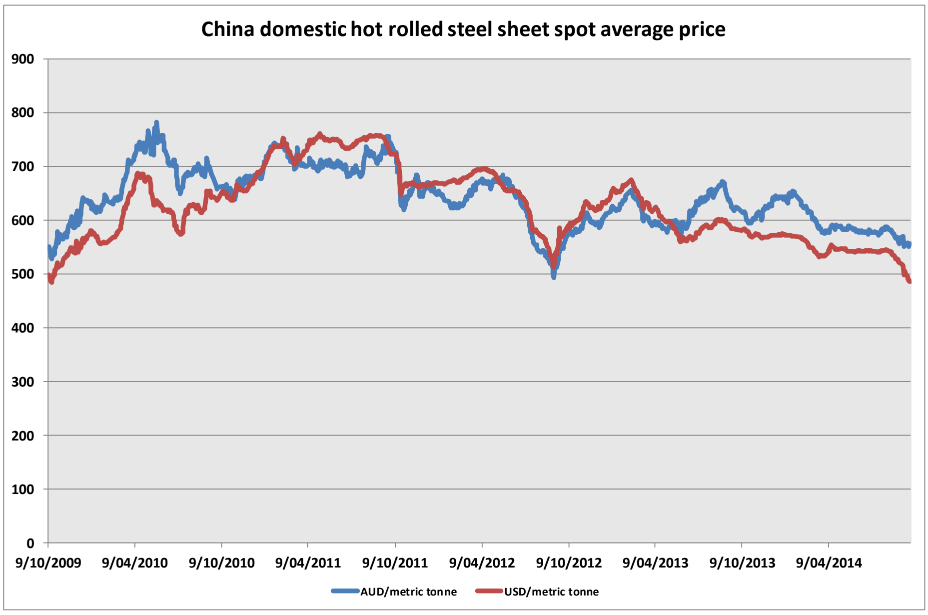
Cost of materials

There have been significant increases in the cost of materials. The price of Hot Rolled Coil steel ex-Asia, used for tubulars and gas transmission pipelines, increased from around US$200/tonne in the early 2000s to over US$700/tonne in 2011. Prices have since declined (in US$ terms) to around US$500/tonne but they are still significantly higher than during the 2000s.

Figure 12 shows steel sheet rather than steel coil but it shows the same pattern.

[1] Simshauser, Paul; and Nelson, Tim (2014), Solving for 'x'- the New South Wales Gas Supply Cliff. AGL Applied Economic and Policy Research. Working Paper No. 40.

Figure 12 China domestic hot rolled steel sheet (US$/t)



Source: Bloomberg

Labour costs

High Australian labour costs are one of the drivers of higher costs. Figure 13 shows some examples of high costs quoted at the 2014 APPEA Conference. It compares costs incurred on Apache's current Brunello development with costs for the 2007 Angel, 2009 Pluto and 2010 Reindeer developments. Salaries have increased by 44-49%.

Bechtel has quoted earnings of $3,000 per week for special class welders, the equivalent of $156,000.

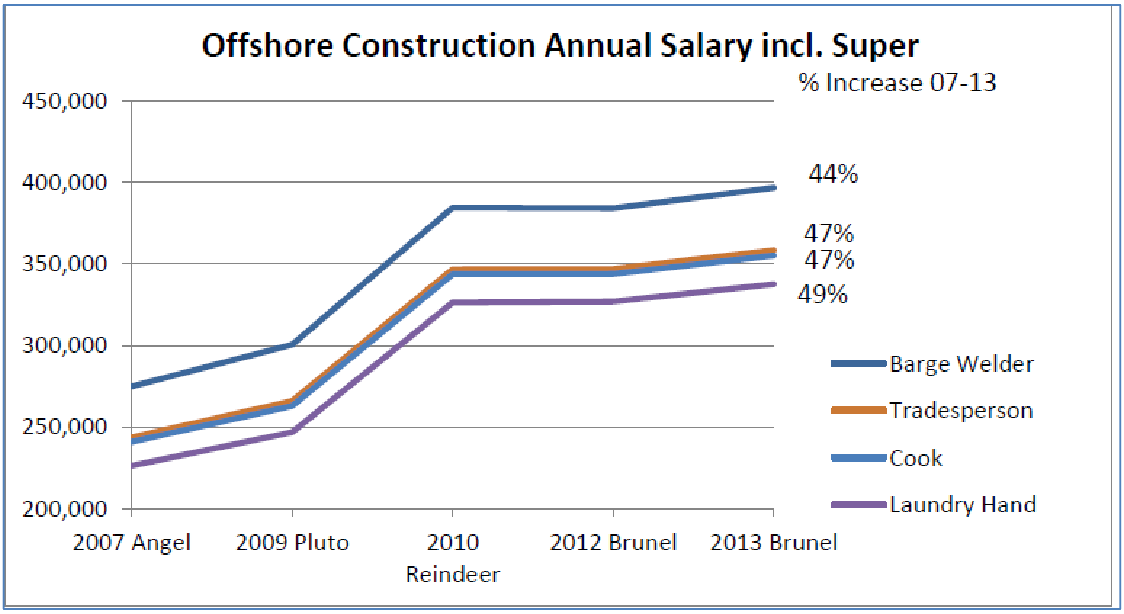
Incitec has said that it will cost around $1 billion to build its new ammonia plant in the US compared with $1.4 billion in Australia. Labour costs would be 35% of the total project in the US compared with 60% in Australia.

Under the enterprise bargaining agreement (EBA) applying to one upstream CSG development in Queensland a fly-in-fly-out trades assistant working earns around $40 per hour, itself high. However with overtime and other allowances this can be leveraged to $160,000 a year.

In August workers on Curtis Island voted to accept a new EBA. The previous EBA expired in June this year and had to be renegotiated, while the projects are still under construction. Bechtel made an offer, now accepted, of a 13% pay increase and an ultimate shift from a 4on/1off roster to a 3on/1off roster, all potentially increasing costs. While Bechtel bears labour cost risk, this all adds to project costs.

The Australian Financial Review reported (28 January 2014) that an unskilled labourer could earn a starting wage of $180,000 a year under the greenfield EBA applying to construction of the gas conditioning plant at Longford.

Figure 13 Offshore construction annual salary including superannuation



Source: AMMA

SEEK reported that annual salaries for oil and gas exploration jobs increased by 13% in 2013 to $158,671.

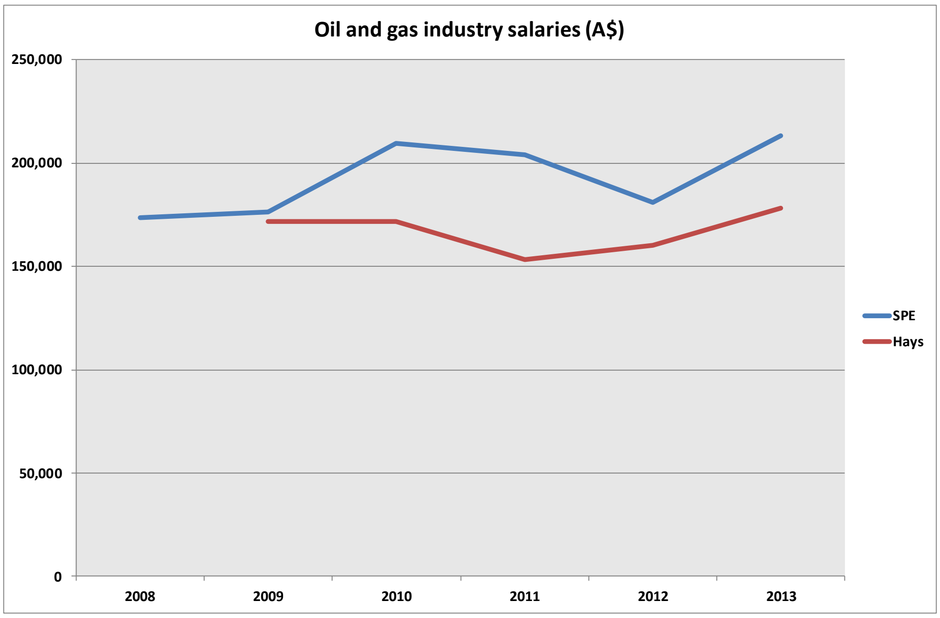
Higher costs reflect not only wages but also poor productivity. According to Shell, Australian oil industry workers are paid approximately 130% of the American Gulf Coast benchmark and Shell has called for a focus on eliminating unproductive clauses in enterprise agreements to maximise effective hours at work. Shell quotes a case of having to pay for 700 hours of work but only getting 500 hours due to restrictive practices. Shell also believes that greenfield industrial agreements should hold for the full term of a project.

It is not only workers under EBA's that are expensive. So are non-unionised industry professionals. The Hays Oil and Gas Salary Survey for 2013 found average Australian oil and gas salaries for permanent staff of US$163,700 pa, the second highest in the survey after Norway. In 2013 average Canadian salaries were US$130,000 and US salaries US$111,800.

In the salary survey of SPE members, median total compensation in Australasia in 2013 was US$195,952, the highest in the world, up by 11.7% from 2010 and by 6.4% from 2012. (The average wage increases in the total Australian workforce in 2013 was 2.5%.) Median 2013 compensation of SPE members in the US was US$192,600 and average Canadian compensation was $161,750.

Figure 14 shows salaries from the Hays and SPE surveys in A$.

Figure 14 Oil and gas industry salaries



Sources: SPE, Hays

Regulation and community benefits

Tighter environmental regulation has also increased costs. For example, a decade ago water produced with CSG in Queensland could be evaporated. It now generally requires reverse osmosis.

Environmental regulation is being rationalised between the federal and state governments and in Queensland.

The repeal of the carbon pricing mechanism in July removes a cost facing LNG exporters and gas producers generally.

A decade ago gas producers were not expected to pay material amounts in compensation to land owners. This has now changed. Producers are also expected to make community contributions, which have totalled $127.5m in Queensland to the end of 2013.

Supply restrictions

Supply restrictions mean that potentially low-cost gas cannot be accessed. Gunnedah and Gloucester gas may be some of the lowest-cost gas on the east coast. In Victoria Lakes Oil is offering gas from onshore fields for $5.25/GJ but is prohibited from drilling. However with restrictions on drilling in NSW and Victoria it is not possible to form a definite view about production costs in those states.

Opponents of CSG development in NSW do not believe that restricting gas supply will increase gas prices. The nub of the argument, from The Australia Institute and others is that east coast Australian gas prices will be set completely by global prices and the only thing that will affect local prices is changes in global prices. This argument has some validity in the case of commodities traded in deep global markets like oil. Discovering more oil in Bass Strait would be unlikely to reduce east coast petrol prices. However, gas is quite different to oil or petrol. Primarily due to the greater difficulties of transporting gas, there is nothing like a liquid global market in gas of the kind there is in oil. Around 60% of oil is traded globally but only 10% of gas is traded as LNG. Any oil produced in Australia can be readily sold on the global market. That is not true of gas. It is not the case that any additional gas produced on the east coast can be sold as LNG. Moreover both AGL and Santos have said that any gas they produce in NSW will only be sold into the local market (the first 100 TJ/d in the case of Santos). Accordingly the price of NSW gas will be determined by its cost, the price of alternative Victorian gas supplies and the price of energy substitutes such as coal.

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