A Brief Review of GeoScience Issues associated with Shale Gas development in Australia

Prepared by
Dr. Dennis Cooke
University of Adelaide/ Australian School of Petroleum, and
ZDAC Geophysical Technologies
For the
ACOLA/ Unconventional Gas Production Working Group
December 10, 2012

OVERVIEW

Various geotechnical aspects of Australian shale gas development are briefly described with a focus on those issues related to the environment: fracture stimulation, methane in ground water and fugitive emissions into the atmosphere. In the author's opinion, the public's concern with fracture stimulation is diminishing and is being replaced with a focus on ground water methane and fugitive methane emissions into the atmosphere. This shift away from fracture stimulation is occurring because time has allowed significant data collection, research and peer review with contamination of water supplies by fracture stimulation chemicals remaining unproven. However time and research has uncovered two new areas of concern: ground water methane and fugitive atmospheric emissions. Methane is a strong green house gas and its sources will come under increased scrutiny with any global warming we may experience. The concept that shale gas operations lead to a net gain in greenhouse gases (as opposed of displacing coal and thus mitigating climate problems) is new and the science and data behind this issue incomplete. Yet this issue is quickly becoming the main concern of the public, regulators and policy makers with respect to shale gas.

CONTENTS

Summary list of potential geoscience-related issues

Disclosure

The author is financially linked to the petroleum industry. His research at the University of Adelaide into unconventional reservoirs is supported by the petroleum industry and he own shares in companies involved in shale gas development.

Brief description of issues

1) Possible price spike for natural gas in Eastern Australia
Some observers are predicting spike in natural gas prices in eastern Australia in the 2014-2016 time frame (The Australian 2012, Financial Review 2012). This price spike – if real – is a problem that Australian shale gas development would alleviate. The drivers behind this possible price spike are:

- E Australia's conventional gas supplies are from old fields, which are approaching the natural end of their field life.
- Existing long-term gas supply contracts - which are fixed at a low price - are expiring.
- Coal seam gas (CSG) gas would normally fill in the above supply gap, but much of Australia's CSG gas is pre-sold to Asian buyers as CSG-LNG.
- Some CSG-LNG exporters have committed to export more CSG-LNG that they own.
- The gas production profile of CSG wells is not optimally suited to supply LNG plants: LNG plants need to operate at max capacity as soon as they start up, but CSG wells may take years before reaching their maximum gas flow.

Australian shale gas development and new gas supplies might solve this predicted price spike. Note that the gas production profile of shale gas wells is quite complementary to CSG wells: shale gas wells have their best production early in well life and rapidly decline in rate while CSG wells start slowly and gradually lincrease. These two profiles can combine to better fit the supply needs of a LNG plant than either well type alone.

2) Negative community impact from drilling thousands of wells
Experience in North America is that the industrial activity associated with the 'shale gas boom' can have a negative impact on communities. The negative impact comes from greatly increased truck traffic and round-the-clock well drilling. Community impact may not be a significant issue in very remote Australian shale gas locations like the Cooper Basin and Northern Territories, but shale gas and tight gas plays are under evaluation in populated areas such as the Gippsland Basin, Otway Basin, Perth Basin and the Bowen Basin. (CSIRO 2012, US Energy Information Administration 2011)

3a) Contamination of water supplies from fracture stimulation
After over one millions fracture stimulation treatments in North America (King, 2012) and over 1300 in South Australia (Pepicelli 2012) [1], there is no evidence of frac fluids moving up in the earth from a frac treatment to a surface aquifer. There are however, continued occasional observations of methane in surface

[1] Pepicelli is an employee at South Australian Department for Manufacturing, Innovation, Trade and Resource (DMITRE). DMITRE currently has a database on all frac jobs performed in the South Australia and is in the processing of making that database public via their web site: http://www.petroleum.dmitre.sa.gov.au

water supplies. There are a few possible sources of this methane – which are discussed in the following section.

The figure below from Fisher and Warpinski, 2011 compares the depth of fracture stimulation treatments for the Barnett Shale to the vertical extent of the created fractures and the distance to surface water supplies. It is this separation between the frac job and the ground water that explains the risk – or lack of it - during fracture stimulation treatments.

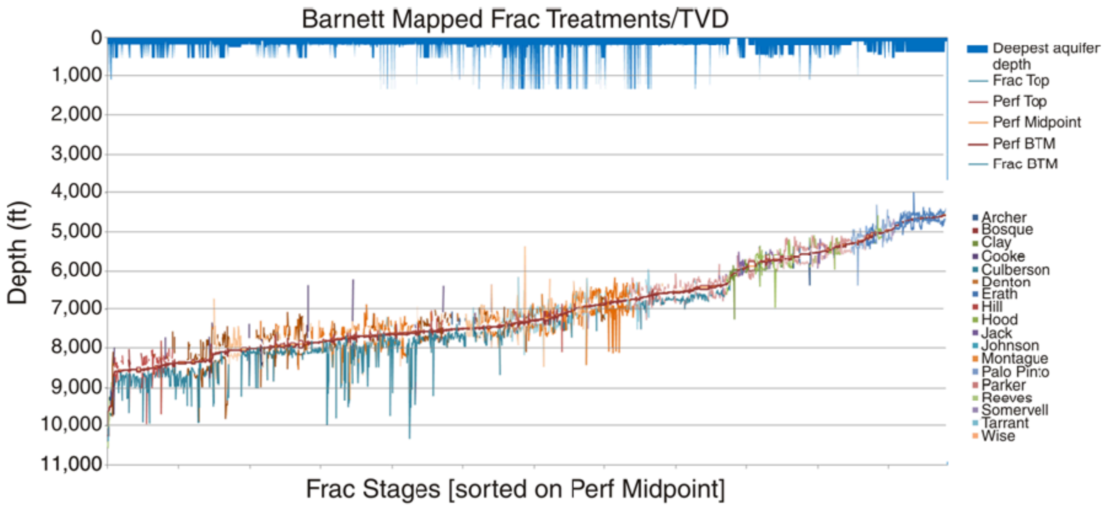

Figure 1 – Barnet shale measured fracture heights sorted by depth and compared to aquifers. From Fisher 2011.

The distance between the fracture stimulation treatment and surface water supplies will change between different shale plays. The figure below shows the depths of shale gas and surface water supplies for the Cooper Basin of Australia where shale gas develop is just starting (figure take from the DMITRE web site: http://www.petroleum.pir.sa.gov.au/prospectivity/basin_and_province_information/unconventional_gas/frequently_asked_questions

Figure 2 shows 3000 m. (~9,900 ft.) separation between the surface water supplies (Lake Eyre Basin, in yellow at the top of the figure) and the fracture stimulation target (Roseneath and Murteree shales) – a distance greater than in the Barnett shale. However, this figure also shows that the shale gas reservoirs are considerably closer to the aquifers of the Great Artesian Basin (Cadna-owie, to Hutton formations in light and dark blue).

As pointed out by both Fisher & Warpinski (2011) and Davies (2012) fracture stimulation treatments that travel the greatest vertical distance are those that break into pre-existing natural faults. Davies (2012) cites a maximum frac height of 588m for such a frac treatment. If a 588 m. fault-conveyed fracture treatment can occur in the Cooper Basin , the Hutton formation is theoretically within range of a frac treatment in the Roseneath Shale.

Figure 3 shows a large Cooper Basin fault and illustrates how to minimize risk to the Hutton formation from fracture stimulation treatments in the Roseneath shale. This figure shows a seismic line over the Big Lake Field in the Southern Cooper Basin. The Big Lake fault is clearly visible in the lower right. As is commonly done in US shale plays, Australian shale gas development could use 3D seismic like this to map locations where fault risks exist and avoid fracture stimulation in the immediate vicinity. Other useful mitigation procedures would be geomechanical modeling to predict the susceptibility of different fault orientations to conduct fluids and microseismic to map in real time growth of a fracture stimulation treatment and shut down that treatment if unwanted height growth is observed.

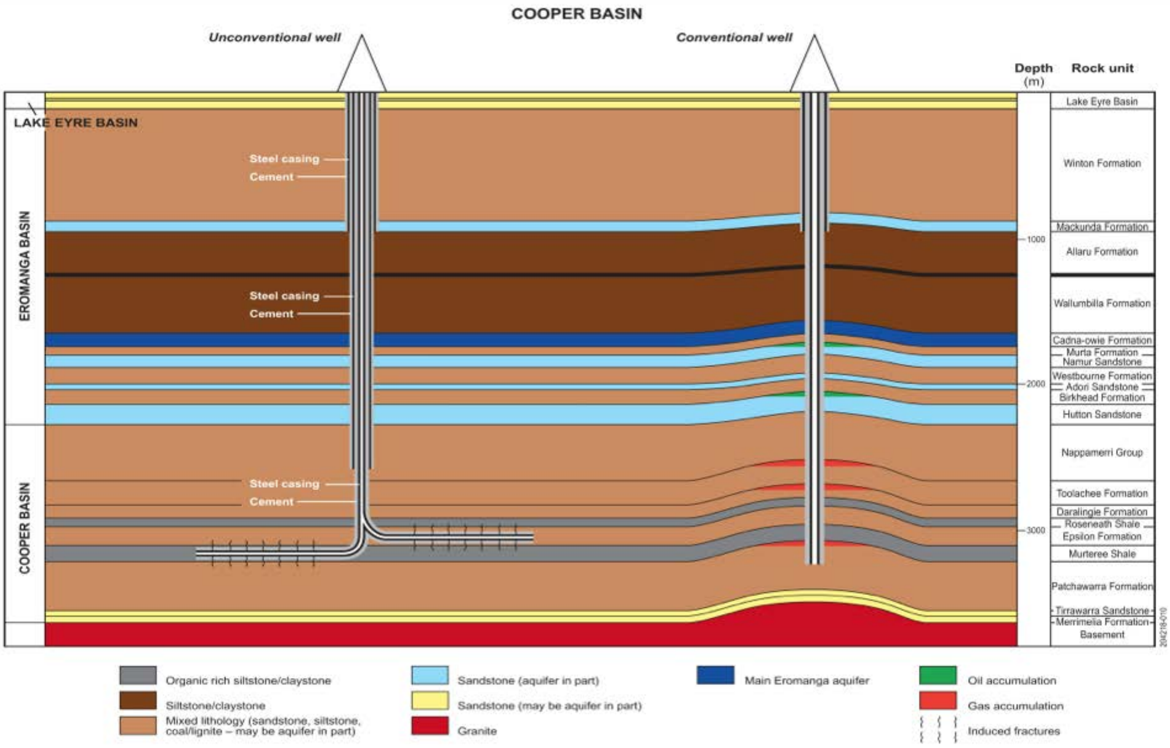

Figure 2 – Schematic diagram showing both an unconventional and conventional well in the Cooper Basin. Taken from the DMITRE web site.

A closely related issue is the toxicity of the chemicals used in fracture stimulation and their threat to the safety of aquifers. An analysis of the chemicals used and their toxicity is beyond the expertise of this author, but the author notes that concerns about toxicity are being addressed by shale gas developers with the following actions (King 2012). Those companies are:

- Revealing what chemicals are used in fracture stimulation treatments,
- Pointing out that those chemical are at very low concentrations,
- Communicating other areas where the public comes into contact with same those chemicals: for example the 'friction reducer' used in fracture stimulation treatments is also found in nappies,
- Removing/ reformulating chemicals where needed and where possible: For example some fracture stimulation contractors can use UV light instead of a biocide to remove unwanted bacteria.

The public may also find that their concerns about contamination of the Great Artesian Aquifers are alleviated by understanding that those aquifers contain numerous oil fields: In the Cooper Basin, there are over 500 oil wells drilled to the Cadan-owie to Hutton reservoirs and those wells have produced over 160million barrels of oil since 1982 (DMITRE PEPs database, 2012).

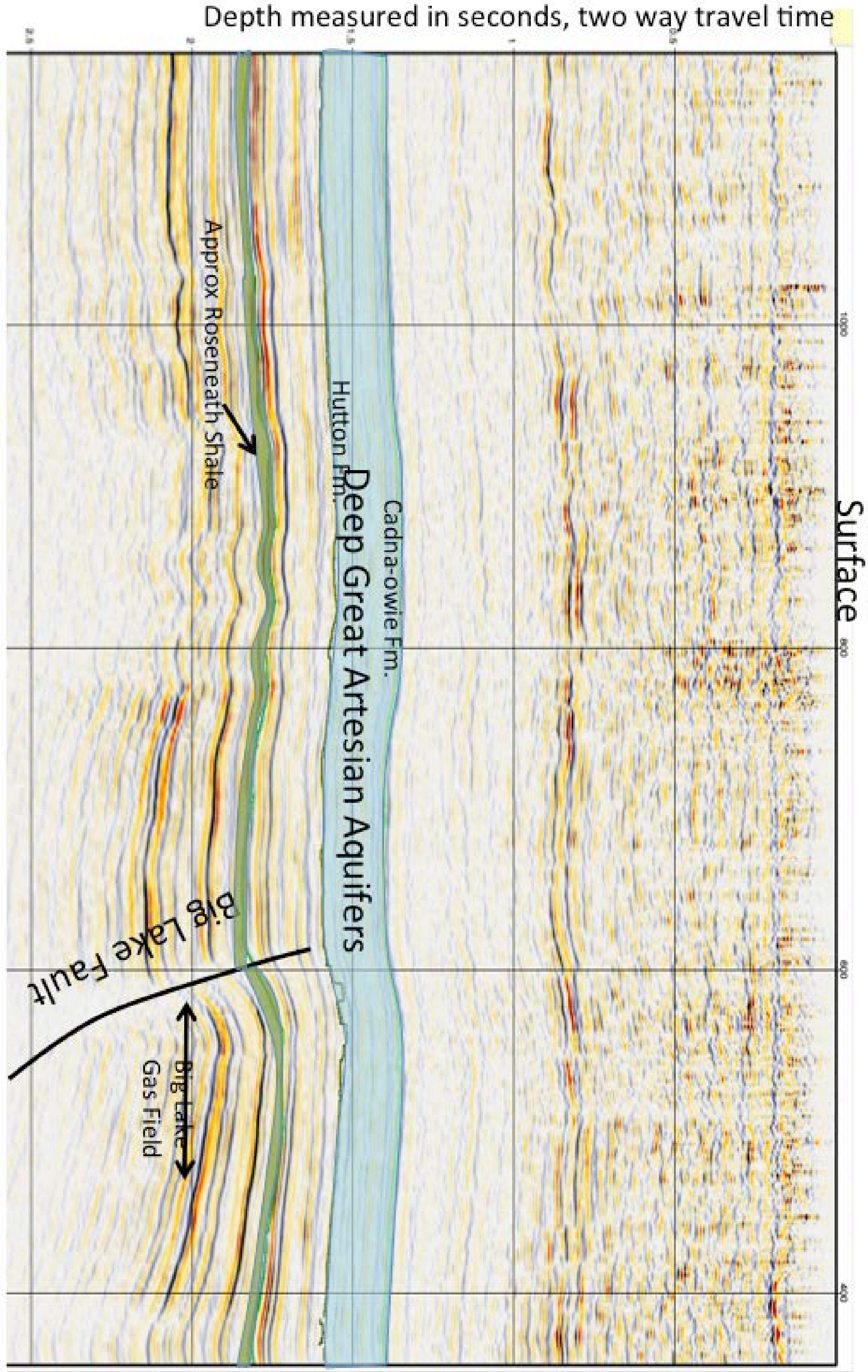

Figure 3: East-West seismic line showing that major faults – which are possible conduits for fracture stimulation fluids – can be located with seismic data and thus avoided when locating fracture stimulation treatments.

3b) Methane in water supplies near shale gas wells

Osborn et al (2011) report methane in ground water supplies near shale gas wells in Pennsylvania. Other authors (King 2012, Daily Journal 2011) point out that methane also occurs in water wells in areas with no shale gas drilling. The source of this methane is not well understood. It could be coming from:

- Casing leaks in the fracture stimulated wells: a fracture stimulation target is usually a few kilometers below the surface aquifer, but fluid communication between the well and the aquifer where the well passes through the aquifer is theoretically possible. Well construction and casing design is beyond the scope of this report, but it is discussed by King (2012).
- Natural flow of methane up faults and into the surface water supplies. This flow of methane and is documented in offshore petroleum basins where it is easy and frequently observed (Ilg et al, 2012)
- A combination of pressure depletion in surface aquifers, coals in those surface aquifers and casing integrity problems in the surface water wells.

3c) Fugitive emissions from shale gas drilling and production activities

Fugitive emissions do occur from flow-back of frac water and leaks in production equipment and in transmission/ distribution pipelines. Unlike all of the above-mentioned environmental issues, these fugitive emissions leak methane into the atmosphere and thus are a global climate issue and not a local contamination concern.

Howarth (2011) estimates that fugitive methane emissions associated with the process of completing shale gas wells is so large as to remove any greenhouse-gas advantage that shale gas may have over coal. Other authors (King (2012), O'Sullivan and Paltsev 2012) challenge Howarth's assumptions used in calculating the volume and impact of the fugitive emissions and O'Sullivan estimates a considerably lower volume of fugitive methane emissions.

The US EPA recognizes this as a significant issue and has defined new regulations requiring 'green completions' of shale gas wells. These regulations require capture and sale (via a natural gas pipeline systems) of this methane instead of the previous process of venting and/ or flaring that methane (US EPA publication 2012).

3d) Natural fugitive emissions: hydrocarbons migrating out of the earth.

Santos and Maher (2012) have observed higher than expected methane concentrations at an Australian coal seam gas (CSG) field and speculated that fracture stimulation has lead to that increase. Unlike the mechanical leaks that can be mitigated with green completions, this speculated fugitive emission would be much more difficult to control. While fracture stimulation might be responsible for those emissions, there are other possible sources:

Ancient biomass buried deep in the earth is converted to hydrocarbons (including methane) by heat. A significant percentage of these thermogenic hydrocarbons migrate to the surface along faults and vent to the atmosphere (Ilg et al, 2012). The most well known of these vents might be sea floor 'black smokers', but they probably exist in most onshore and offshore sedimentary basins.

Relevant to this issue is a comparison of the volumes of methane being introduced into the atmosphere from all sources, as any global effort to control greenhouse gasses would logically focus initially on the largest and easiest to control sources. The science in this area is very new and evolving very quickly, and Lavelle (2012) presents a good summary. She estimates that anthropogenic methane accounts for 59% of US emissions and the natural gas industry generates a significant portion of that.

3e) Induced seismicity

When large volumes of water are injected into the earth (as in a frac job) at or near a 'critically stressed fault', the fault can slip causing an earthquake. This is a problem rather well understood by the science of geomechanics. Earthquakes have been documented by waste injection/disposal, geothermal water injection and in a few cases by shale gas fracture stimulation activities. As this problem is much more likely from geothermal water injections (much higher volumes of injected water than in frac stimulation), the geothermal community is proposing guidelines and self-regulation to control induced seismicity. Maxwell and Feher (2012) present a good summary of the science of induced seismicity.

3f) Frac flow-back water

The water injected during shale gas fracture stimulation treatments must be flowed back from the fractures and well bore before gas flow can occur. (King 2012). This water might contain dissolved methane and may have high salt content. In some areas, this frac flow-back water contains minute radioactive minerals debris from the shale. Disposal of this water can be an environmental issue. Where appropriate, regulations are mandating reuse of the water in other frac jobs. This is an area that Australia should consider investigating and regulating if needed.

4) Comparison of North American and Australian shale gas development

a. Cost structure: It is still too soon to tell if Australian shale plays will be economic. The cost of drilling and fraccing wells in Australia is currently at least two to three times more expensive than in North America. Australian shale gas well costs are likely to come down as North American 'batch' drilling practices are deployed in Australia, but higher labor costs and more remote locations preclude Australian costs from equaling North American costs.
b. Shale types: Shales are characterized by their organic content, thermal maturity, porosity, permeability, reservoir pressure and mineral content. Many different shale types have been tested in North America. Some – but not all – are commercially successful. Some Australian shale plays

have similar characteristics to successful North American shales. (US EIA 2011). Experience in North America has shown that a) each new shale play is different and b) many of those differences can be addressed with different drilling and fracture stimulation practices.

c. Tectonic stress: Most North American shale plays (all?) are in an extensional tectonic stress regime (as is most of the North American continent). Australian shales experience higher compressive tectonic stress, which may complicate local shale gas development. Higher horizontal tectonic stress will lead to diminished frac height growth, smaller 'stimulated reservoir volumes' per frac stage and thus to more frac stages per horizontal well and higher devlopment costs.

d. Lessons learned from deep frac treatments in Australia: There have been over 1300 (Pepicelli 2012) fracture stimulation treatments in the Cooper Basin in the past 20 years in tight gas reservoirs (see section below for discussion of tight gas). There have been no observed instances of contamination of water supplies from these frac treatments.

   There have been just a handful of shale gas wells drilled in Australia – and none of those wells have used the key to North American shale gas success: horizontal drilling with multi-stage fracture stimulation treatments. However, horizontal shale gas wells will be tested very soon in the Cooper Basin by Santos and Beach Energy.

   Recent vertical shale gas wells by Santos and Beach have had reasonably good flow rates for that type of well. http://www.santos.com/Archive/NewsDetail.aspx?id=1347

e. Technical innovation and transfer that may be applicable to Australia: New shale gas plays in North America are tested with 'pilot programs' where many different drilling and fracture stimulation techniques are tested. Pilot programs typically include 4-8 wells at a cost of up to $10M/well. Variables tested in pilot programs include different drilling and fracture stimulation fluids, different hydraulic isolation techniques, and different treating pressures, pumping rates and proppant types. It is not yet clear which techniques – if any – will lead to commercial shale gas success in Australia, but it is clear that North American technology is available to Australian shale gas operators via service companies and North American partners.

5) Differences between shale gas and coal seam gas (CSG)

The major difference between Australian shale gas and Australian CSG is that CSG reservoirs are much shallower and development of CSG requires draining water from the coal before gas flow will occur. See the table below for more details

	Shale gas	**Coal seam gas**
Reservoir depth	1500-4000m	Typically 200-1000m
Fluid initially found in reservoir	Gas with trace amounts of water	water
Gas storage mechanism	Free gas in pore space, some adsorbed gas	Only adsorbed gas
Fracture stimulation	Needed in 100% of shale	Used in 7-40% of CSG gas

	gas wells	wells
Gas production rate	2-20 mmcfpd	.2-2 mmcfpd

6) Similarities between shale gas and tight gas/ basin centered gas
As Australian gas companies evaluate shale gas plays, they are also evaluating tight gas plays. Both shale gas and tight gas are an unconventional reservoir. Tight gas reservoirs have more silt and less clay than shale gas reservoirs, but the difference between the two is gradational. An example: some geologists argue that the Roseneath shale of the Cooper Basin (a promising Australian shale gas play) not a real shale, but a siltstone – as is the Barnett shale in Texas. The important similarities are that both shale gas and tight gas require fracture stimulation and large numbers of development wells.

7) Studies needed to mature shale gas in Australia:
At this time, the most needed research – which is ongoing - are the pilot programs where Australian exploration companies are evaluating shale geologic parameters (TOC, porosity, thermal maturity etc.) and testing different drilling and fracture stimulation techniques.

Risk Assessments

Gas supply shortage and price spike	Likelihood	Consequences	Description of Consequences
Assessment	Likely	Large	Consequences are social and financial, not environmental
Reliability	Medium	Medium	
Risk management/ mitigation	Risk management would require a study of expected Eastern Australian gas supply & demand for the 2014-2016 time frame. This is a risk that Australian shale gas development would alleviate.		
Comments	This issue – if pursued – needs review by gas market specialists with support from a petroleum engineer predicting CSG production growth rates.		

Negative community impact from drilling thousands of wells	Likelihood	Consequences	Description of Consequences
Assessment	Likely <u>only for shale gas development in more populous areas</u>	Large	Social
Reliability	High	High	

Risk management/ mitigation	Keep shale gas development in remote areas. If in more populous areas, regulate truck traffic and drill rig noise.
Comments	This is the largest impact from N American shale gas development.

Contamination of surface water supplies from fracture stimulation	Likelihood	Consequences	Description of Consequences
Assessment	Highly unlikely for shale gas	Medium	Environmental
Reliability	Medium	Medium	
Risk management/ mitigation	3D seismic and micro seismic lowers likelihood. Frac fluids w/o biocide or synthetic lubricants lowers consequences		
Comments	'Hot button issue'. Little (no?) real health damage likely, but very negative public perception.		

Methane in surface water supplies	Likelihood	Consequences	Description of Consequences
Assessment	Unlikely at any one location.	Medium -High	Environmental
Reliability	Medium	Medium	
Risk management/ mitigation	3D seismic and micro seismic lowers likelihood. Frac fluids w/o biocide or synthetic lubricants lowers consequences		
Comments	Causes of this infrequently observed phenomena are not well understood.		

Fugitive emissions from gas production activities	Likelihood	Consequences	Description of Consequences
Assessment	Unlikely at high levels, likely at small levels	Medium -High	Environmental
Reliability	Medium	Medium	
Risk management/ mitigation	Establishment/ regulation of best practice for well completion practices		
Comments			

Fugitive emissions from natural sources	Likelihood	Consequences	Description of Consequences
Assessment	Unlikely at high levels, likely at small levels	Medium -High	Environmental
Reliability	Medium	Medium	
Risk management/ mitigation	Measurement of background methane levels		
Comments			

Induced seismicity	Likelihood	Consequences	Description of Consequences
Assessment	Unlikely	Medium	Social
Reliability	Medium	Medium	
Risk management/ mitigation	3D seismic to identify major faults Geomechanical studies to establish fault slip susceptibility		
Comments			

Frac flow-back water issues	Likelihood	Consequences	Description of Consequences
Assessment	Medium-High	Medium-High	Environmental
Reliability	Medium	Medium	
Risk management/ mitigation	Early measurement of contents of frac flow back waters for different Australian shale plays needed. Regulation re: disposal of those waters if they are contaminated.		
Comments			

References Cited

The Australian Newspaper, April 24, 2012: Gas shortage looms as LNG demand grows

CSIRO 2012, Australia's shale gas potential, http://www.csiro.au/en/Outcomes/Energy/Energy-from-oil-and-gas/Shale-gas-potential.aspx

Davies J.D., Mathias S.A., Moss J., Hustoff S., Newport L., 2012: Hydraulic fractures: How far can they go?, published in Marine and Petroleum Geology, Elsevier Press

The Daily Journal: "Chesapeake: 11 Percent of water wells contain methane before drilling," August 7, 2011

DMITRE PEPs database, 2012: The South Australian government's Department for Manufacturing, Innovation, Trade and Resource (DMITRE) maintains a publicly accessible database (PEPs) on oil and gas production that can be downloaded at:
http://www.petroleum.dmitre.sa.gov.au/access_to_data/peps-sa_databas

Financial Review, 12 December 2012, "LNG exports to hit domestic gas prices"

Fisher, K and Warpinski, N, 2011 Hydraulic Fracture-Height Growth: Real Data, Paper SPE Paper 145949 Presented at the Annual Technical Conference and Exhibition, Denver Colorado, USA.

Howarth R.W., Santoro R., Ingraffea A.,2011, Methane and the greenhouse-gas footprint of natural gas from shale formation, A Leter, Published in Journal Climate Change, Springer Press

Ilg, B.R., Hemmings-Sykes S., Nicol, A., Baur, J., Fohrmann, M., Funnell, R., Milner, M., 2012, Normal faults and gas migration in an active plate boundary, southern Taranaki Basin, offshore New Zealand, published in the AAPG Bulletin, September 2012.

King, G.E., 2012: Hydraulic fracturing 101: What every representative, environmentalist, regulator, reporter, investor university research, neighbor and engineer should know about estimating frac risk and improving frac performance in unconventional gas and oil wells. SPE Paper 152596, presented at he The SPE hydraulic fracturing technology conference, The Woodlands, Texas, Feb, 2012

Lavelle M. 2012. Good Gas Bad Gas, published in National Geographic magazine, December 2012

Maxwell S., Fehler, M. Workshop Report: SPE/SEG workshop on Injection-induced seismicity, published in the December 2012 issue of 'The leading edge' by the Society of Exploration Geophysicists.

Osborn, S.G., Vengosh, A., Warner, N. R., Jackson, R.B. 2011, Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing, PNAS Early Edition. http://www.pnas.org/content/early/2011/05/02/1100682108

O'Sullivan F., Paltsev S.2012, Shale gas production: Potential versus actual greenhouse gas emission, published in Environmental Research Letters

Pepicelli, D. 2012; Personal communication.

Santos I., Maher D., 2012, Submission to the Australian Department of Climate Chane and Energy Efficiency. http://www.scu.edu.au/coastal-biogeochemistry/download.php?doc_id=12515&site_id=258&file_ext=.pdf

US Energy Information Administration, 2011: World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States.

US Environmental Protection Agency 2012: Overview of final amendment to air regulation for the oil and natural gas industry fact sheet. Available at http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf