

Potential Geological Risks Associated with Shale Gas Production in Australia

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FROGTECH Pty Ltd
ABN 29 129 411 981

Po Box 250 - Suite 17F, Level 1
2 King Street
Deakin West ACT 2600
AUSTRALIA

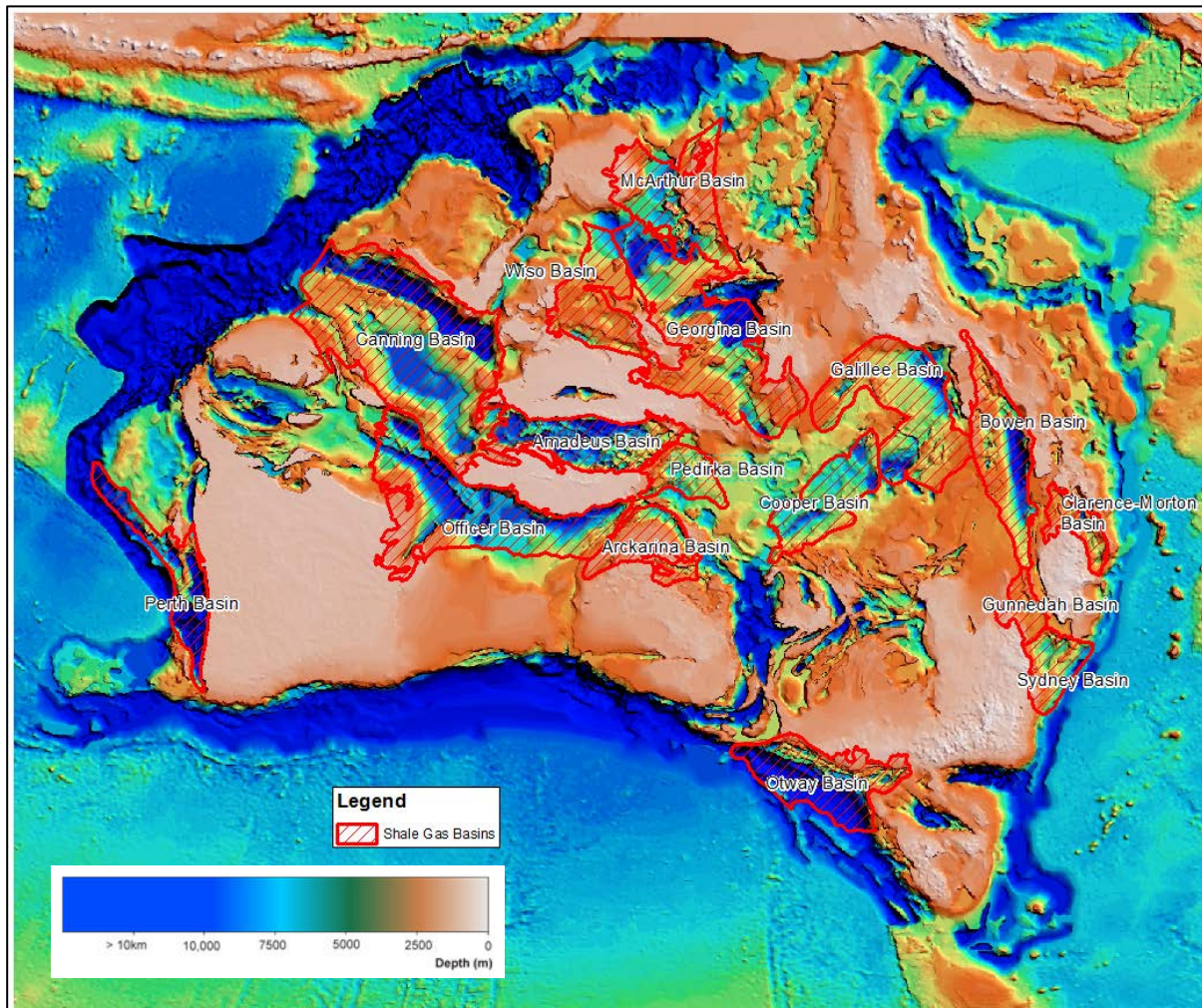
T +61 02 6283 4800
F +61 02 6283 4801
E info@frogtech.com.au
L [linkedin.com/company/frog-tech](https://www.linkedin.com/company/frog-tech)
W frogtech.com.au

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Executive Summary

There is huge potential for exploiting shale gas resources in Australia. Estimated reserves are twice the size of those projected for coal seam gas with most basins located in rural and remote Australia.



Major shale gas basins in Australia over OZ SEEBASE™ modified from (Geoscience Australia and BREE, 2012).

Comparison to coal seam gas

There are potential parallels with the coal seam gas (CSG) industry but there are also important differences as well. However, much of the work developed for the Bioregional Assessment process for the assessing the impact of CSG by the Office of Water Science may also be applicable for shale gas.

Some important differences include the fact that unlike CSG in Australia, where about 10-40% of wells are hydraulically fractured or “fracked”, virtually 100% of shale gas wells will be need to be fracked. In addition, shale gas wells tend to be deeper than CSG wells with average depth ranging from 1000-3000 metres. Also, because shales tend to act as aquitards, shale gas wells produce much smaller volumes of produced water, although it may be very saline (greater than three times seawater) and the water may contain a range of harmful chemicals, which will limit treatment and reuse possibilities.



Geological risks

Thus far, the majority of shale gas development has taken place in the United States and to a lesser extent in Europe. This development has shown that the primary geological risks of shale gas development are induced seismicity, water management and well integrity.

Induced seismicity

Along with mining, dams and other activities, fracking if improperly conducted, may cause low level earthquakes. However, out of the tens of thousands of wells drilled for shale gas thus far there have only been a few documented examples of induced seismicity due to fracking. Risks may be lowered by understanding natural faults, fractures, and stress directions.

Future Consideration 1

To minimise the risks associated with induced seismicity.

- Develop the necessary scientific background on seismicity and structural geology, preferably led by an independent agency such as Geoscience Australia or CSIRO. Such activities include:
 - Mapping and characterising stresses, faults including orientations and strike slip tendencies.
 - Mapping the direction of bedding planes within shales.
 - Building ground motion prediction models for affected regions.
- Establish a traffic light control system for responding to an instance of induced seismicity. Components of a traffic light control system include:
 - Monitoring seismicity before, during and after fracking.
 - Establishing action protocols in advance.
 - Developing an Australian appropriate seismicity model for seismicity. Until such a model is developed, Australia adopts world best practice trigger levels to manage seismicity caused by fracking and fluid injection such as 0.5 M_L used by the United Kingdom (Green at al. 2012).
 - Developing the ability to alter plans on-the-fly such as changes to injection rates.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Publicising the processes and techniques to be employed in area.
 - Publicising action protocols and risk reduction plan in the event seismic trigger values are reached.
 - Reporting seismic incidents related to well construction, operation and abandonment.
 - Explaining the goals and expectations of project.
- Develop a checklist to determine if fracking and fluid injection might cause seismicity such as developed by NAS (2012). Example checklist questions include:
 - Are large earthquakes (M_L) known in the region?
 - Are earthquakes known near the fracking site?
 - Is the rate of activity near the fracking site high?
 - Are faults mapped within 20 km of site?
 - Are these faults active?
 - Is the site near tectonically active features?
 - Do stress measurements in the region suggest rock is close to failure?
 - Are proposed fracking practices sufficient for failure?
 - If fracking has been ongoing at the site, is it correlated with earthquakes?



- Are nearby fracking wells associated with earthquakes?
- Develop a set of best practice fracking methods such as minimising pressure changes at depth.

Water management

Water management is a broad term covering the volume of water used for fracking and drilling, protection of potable aquifers and the handling and disposal of produced water.

Water use

Most of the potential shale gas basins in Australia are located in semi-arid to arid regions and are therefore mostly reliant on slowly recharged groundwater. A fully developed shale gas industry in an arid area has the potential to become a major user of groundwater relative to sustainable extraction levels. As a result, it would be useful to examine fracking water use to determine the effects of groundwater withdrawal on the environment and other users. In addition, other sources of fracking fluid such as recycled water and/or waterless fracking methods could be explored to help reduce the impacts of fracking on the groundwater system.

Protection of aquifers

Under normal conditions, there is little risk of fracking chemicals/produced water contaminating aquifers. This is primarily due to the fact that shale gas resources tend to be well below the depth of potable aquifers and that shales act as aquitards. However, potential contamination may come from well failure, stimulating fractures/faults and poor handling of produced water.

Disposal of brine

Produced water is a highly saline mix of recovered fracking fluid and connate water from the shale. Typically from 30-70% of injected water is recovered. When this water reaches the surface it must be stored, treated and disposed of properly to avoid damage to the environment, people and water supplies.

Future Consideration 2

To protect groundwater and surface water resources:

- Develop the necessary scientific background preferably led by independent agency such as Geoscience Australia or CSIRO. Such activities include:
 - Building a nationwide database of the geochemistry of shale brines.
 - Understanding natural occurrences of methane in groundwater including the potential source prior to large-scale shale gas development.
 - Building a comprehensive database of deep groundwater, including time series data and data loggers in key locations.
 - Developing a comprehensive model of the tectono-stratigraphic framework of shale gas basins including mapping faults, fractures, lithology, tops and bottom of key units, stress direction, facies architecture etc. The resulting information might then be made available and serve as the basis for groundwater and other modelling. A key feature being that the model is iteratively expanded as more information becomes available.
- Collaboration between the states and Commonwealth is vital to developing a transparent and consistent regulatory framework for shale gas. Components of the framework include:
 - Developing guidelines on storage, reuse and disposal of fracking fluids across Australia. The goal being to reduce, reuse and recycle produced water where possible.
 - Modifying existing CSG regulations where appropriate, or adopt best practice guidelines for the handling of produced water from other countries.



- Developing setback rules (minimum distance to other users) to protect other groundwater users (including groundwater dependent ecosystems) and surface water resources.
- Developing minimum values for vertical and horizontal separation of shale gas resources from potable aquifers based on best practice.
- Considering the banning chemicals that pose a risk to public health or the environment.
- Including the volume of water used for fracking within calculation of sustainable limits.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Publicising action protocols and risk reduction plan in the event groundwater contamination is detected.
 - Disclosing the makeup of fracking fluid via a fracking chemical database.
 - Adding nontoxic environmental tracers to fracking fluid help to make cases of potential contamination more evident.
- Companies interested in exploiting shale gas resources may as part of their application:
 - Model the cumulative effects on the groundwater resource prior to fracking.
 - Understand the potential chemical and hydraulic effects of injecting produced water into a saline aquifer.

Well integrity

Well failure through blowouts, annular leakage (along the well) or radial leakage (perpendicular to well) is the primary cause of groundwater contamination from unconventional energy production. A range of industry standards exist to protect both non target resources and to maximise gas recovery.

Future Consideration 3

To help lower the risk of well failure and manage the effects of failure:

- Collaboration between the states and Commonwealth is vital to developing a transparent and consistent regulatory framework for shale gas. Components of the framework include:
Components of the framework include:
 - Enforcing best practice drilling, well completion and decommissioning standards need to be mandated to protect and isolate potable aquifers and environmental values.
 - Reviewing and improving well completion guidelines as experience and technology permits.
 - Employing independent inspectors with the requisite qualifications as well as an appropriate level of impartiality and independence from operators and those with a financial interest in the project. Ideally inspections should continue after decommissioning.
 - Developing trigger values indicating problems linked to remedial actions.
 - Well operators submitting an abandonment plan to the relevant authorities, with open-ended liability for failures into the future.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Communicating the results of any inspection to the operators and public as necessary.
 - Publicising action protocols and risk reduction plan in the vent of well failure.
 - Reporting any detected well failures and the actions undertaken to remediate problem in a timely and transparent manner.



Introduction

Shale gas production in Australia is in its infancy with just twelve exploration wells drilled as of March 2012. Australia has one shale gas production well which is located in the Cooper Basin. Well flow testing by Falcon Oil & Gas has also proven the unconventional resource potential of the Beetaloo Sub-basin in the McArthur Basin, Northern Territory. There, the middle Velkerri Formation organic-rich shales produced at rates from 50,000 to 100,000 cubic feet of gas per day with condensate also generated. These rates are from a vertical well Shenandoah-1/1A and flow rates are expected to be much greater with horizontal wells and multi-stage fracking.

In contrast, the United States (the world leader in shale gas production) had projected reserves of 482 TCF (~508,500 PJ) in 2010 with an estimated ~400,000 gas wells required (<http://www.eia.gov/forecasts/aeo/>).

Australia has estimated shale gas reserves of 396 TCF or ~435,600 PJ (Figure 1). Based on the US experience of well spacing, the proportional extent of fairways (highly prospective zones) and the size of prospective shale gas basins in Australia, in excess of 200,000 shale gas wells could be drilled. In reality however, development of shale gas in Australia will take place over decades and it will strongly depend on the price of methane and other fluids compared to the drilling/infrastructure costs, which considering the remote nature of many shale gas basins may be high. In addition, improved technologies such as utilising a single drilling pad to drill multiples wells will decrease the number of shale gas well ultimately drilled (see also Table 2).

In comparison, the CSG industry has currently has drilled >5000 wells in Australia.

Shale gas development typically follows three phases:

- Exploration: a small number of wells drilled and fracked to determine the type and amount of gas.
- Production: Commercial drilling of 100s or 1000s of horizontal and vertical wells, which are fracked with the gas collected and sold. Horizontal wells are more common in this phase as it allows the maximum access to the shale gas resource.
- Abandonment: Once production ceases, the well is plugged with cement or other seals to prevent gas and brine entering other units or the surface (Royal Society and Royal Academy of Engineering, 2012).

Resource Category	Conventional Gas		Coal Seam Gas		Tight Gas		Shale Gas		Total Gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
EDR	113400	103	35905	33	-	-	-	-	149305	136
SDR	59600	54	65529	60	-	-	2200	2	127329	116
Inferred	~11000	~10	122020	111	22052	20	-	-	155072	141
All identified resources	184000	167	223454	203	22052	20	2200	2	431706	392
Potential in ground resource	unknown	unknown	258888	235	unknown	unknown	435600	396	694488	631
Resources - identified, potential and undiscovered	184000	167	258888	235	22052	20	435600	396	900540	819

Figure 1: Gas resources in Australia (Geoscience Australia and BREE, 2012).



Shale Gas Basins

The best known, explored and possibly most prospective basin for unconventional resources is the Cooper Basin. The late Early Permian organic rich shales of the Roseneath Shale, Epsilon Formation and Murteree Shale (REM) have all the right characteristics for shale gas. These characteristics include suitable thermal maturity, siliceous mineralogy, consistent organic richness and suitable depth of burial and the presence of overpressure to provide drive for enhanced production (Trembath et al., 2012). The Cooper Basin is also attractive as a region due to the large amount of existing infrastructure including pipelines and processing plants from conventional hydrocarbon exploration and production.

Surrounding the Cooper Basin are a series of Paleozoic basins with good shale gas, basin centred-gas and some shale oil prospectivity. The main basins of interest occur within northern South Australia, far western Queensland and the southern Northern Territory. These include the Officer, Arckaringa, Pedirka, Amadeus and Georgina basins. The most prospective intervals within these basins are thick, extensive and organic-rich Permian shales. Farther north in the Northern Territory and far north-west Queensland is the vast McArthur-Isa basin system. This system of rift, sag, flexural and partially inverted basins contains a series of organic rich shales and dolomitic mudrocks of Proterozoic age. These units are both gas- and oil-prone and are expected to contain large unconventional hydrocarbon resources. However, these basins occur in remote areas with minimal infrastructure and their producibility and commerciality are yet to be proven.

In addition, some relatively well explored basins for conventional oil and gas resources such as the Sydney-Gunnedah-Bowen, Perth and Otway Basins also contain potential shale gas resources.

The following sections look at three shale gas basins in more detail:

- Cooper Basin – Most likely basin to be exploited for shale gas due to the existing infrastructure related to conventional oil and gas exploitation. The Cooper Basin is also of interest because it is located beneath the Great Artesian Basin;
- McArthur Basin – Precambrian basin with high potential for both shale gas and oil shale. The McArthur Basin is stable geologically with relatively low structural complexity;
- Otway Basin – A relatively young basin (Cretaceous), located near existing markets with strong structural controls on stratigraphy and fluid movement. The Otway Basin also has a number of competing users in the subsurface including groundwater, CCS, geothermal and conventional oil and gas.

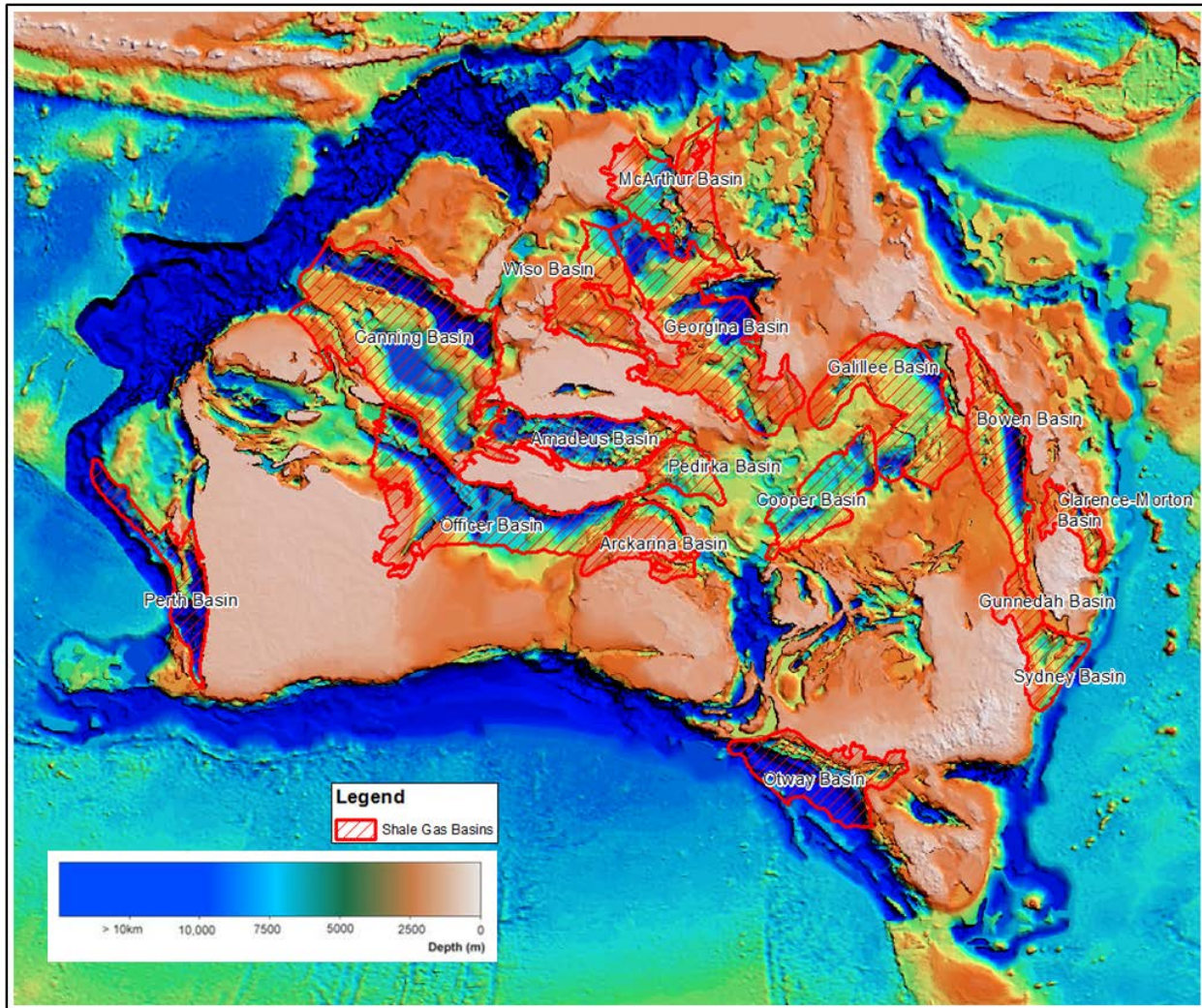


Figure 2: Sedimentary basins with potential shale gas resources in Australia over OZ SEEBASE™ (Structural Enhanced view of Economic BASEment) modified from (Geoscience Australia and BREE, 2012).



Eromanga/Cooper Basin

The Cooper Basin is a Permo-Carboniferous-Triassic intracratonic basin located in the NE part of South Australia and into SW Queensland. The Cooper Basin contains sediments from a variety of depositional settings such as glacial, fluvial, deltaic and lacustrine. The more extensive Jurassic-Cretaceous Eromanga Basin unconformably overlies the Cooper Basin and contains fluvial and lacustrine sediments grading upwards into marine sediments. The Eromanga Basin is the largest of the three basins (including the Carpentaria and Surat basins) that collectively form the Great Artesian Basin (Gravestock et al., 1998).

The siltstones and mudstones of the Early Permian Murteree and Roseneath shales deposited in large, deep lakes form the main shale gas targets in the Cooper Basin. The predominance of carbonaceous and silty shales and coals within the Permian succession also make this region a potential target for basin centred tight gas and coal seam gas (Gravestock et al., 1998).

It is generally a well explored basin for conventional oil and gas resources with over 2900 petroleum wells and over 80,000 line kilometres of 2D seismic and 8830 km² of 3D seismic. There are a number of oil and gas fields (Figure 3) in the basin with Moomba acting as a regional hub (Gravestock et al., 1998).

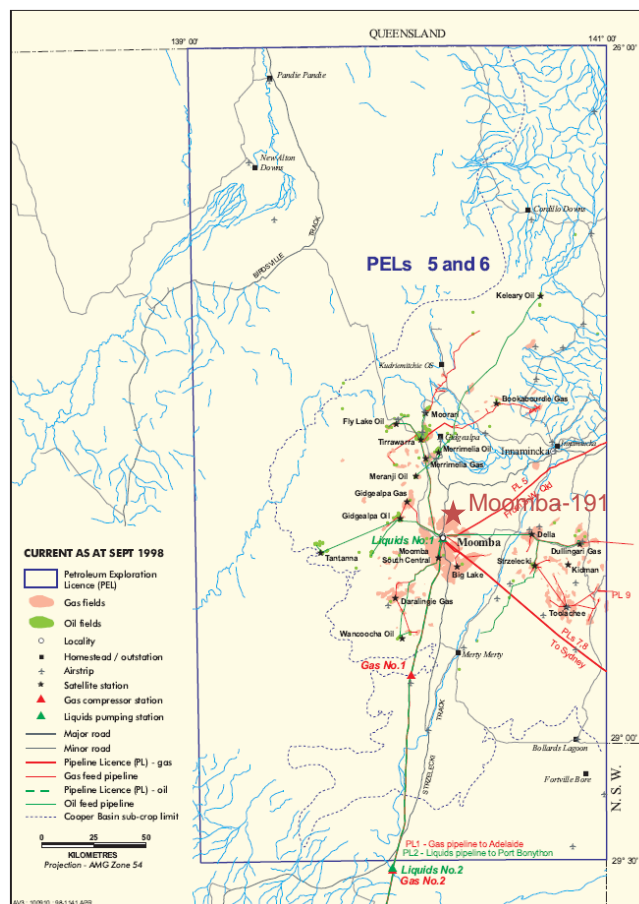


Figure 3: Oil and gas fields of the South Australian Cooper Basin. The approximate location of Moomba-191, Australia's only producing shale gas well shown as a red star (after Gravestock et al., 1998).

The Cooper Basin also has great potential for unconventional oil and gas with a number of potential shale gas and coal seam gas resources from the Roseneath and Murteree Shales and the Epsilon Formation (Figure 4).



The Cooper Basin is also important because it underlies the part of the Great Artesian Basin (GAB) and in some areas the important Hutton Sandstone aquifer directly overlies the Cooper Basin (Figure 4). Separation between the GAB and the most prospective gas shales is variable and structurally complex ranging from 300-800 metres (Gravestock et al., 1998).

Separating the GAB from the gas shales are a number of low permeability beds with the most important being the relatively low permeability Triassic Nappamerri Group which is up to 500 metres thick. The Nappamerri Group is dominantly siltstone; however there are some higher permeability sandstone beds which could act as a preferential pathway between the Cooper Basin and the GAB (Gravestock et al., 1998).

Despite being part of the GAB, groundwater sustainable yield in the Cooper Basin is low with the estimated groundwater footprint (to obtain water for fracking) 139 times the shale gas footprint (NLWRA, 2001 and see Table 2 for explanation of method). This suggests that if widespread exploitation of shale gas resources occurs in the Cooper that alternatives to fresh water such as saline water, reuse/recycling and non-water based fracking fluids be considered.

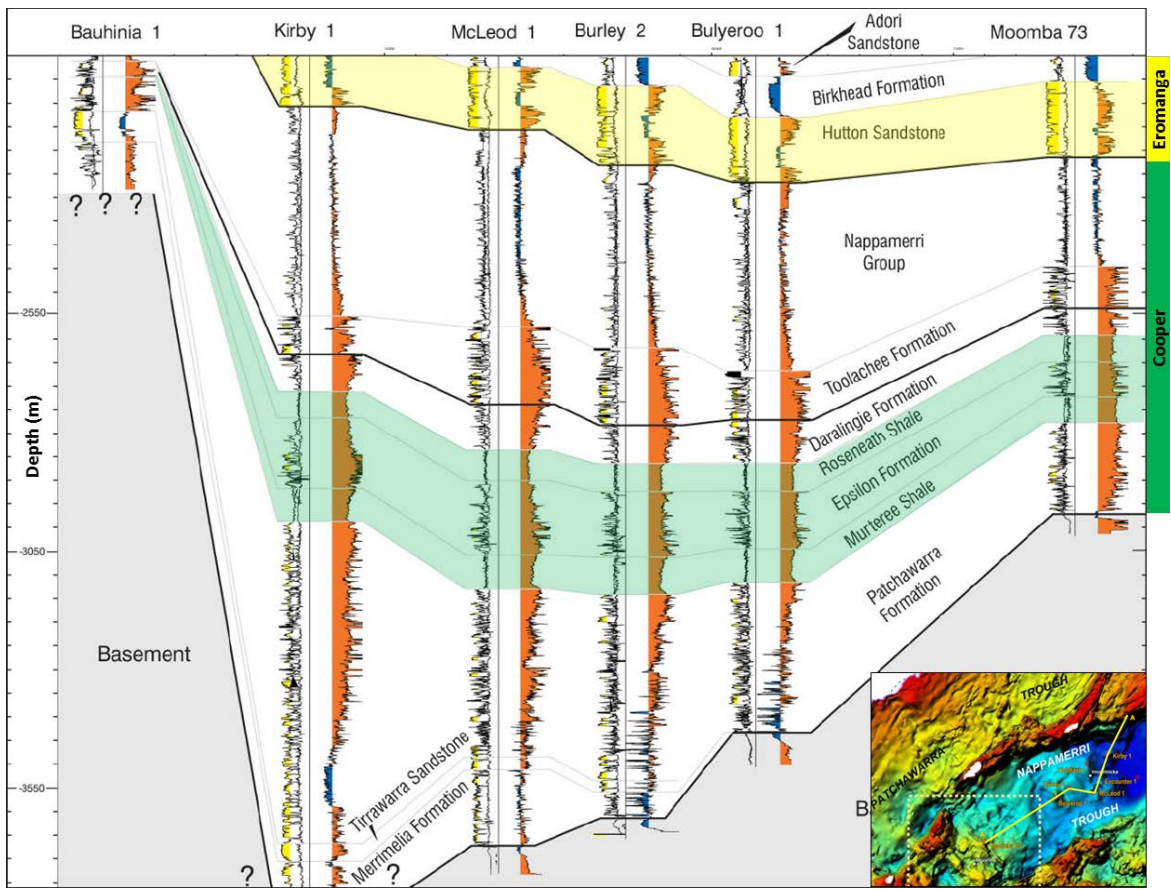
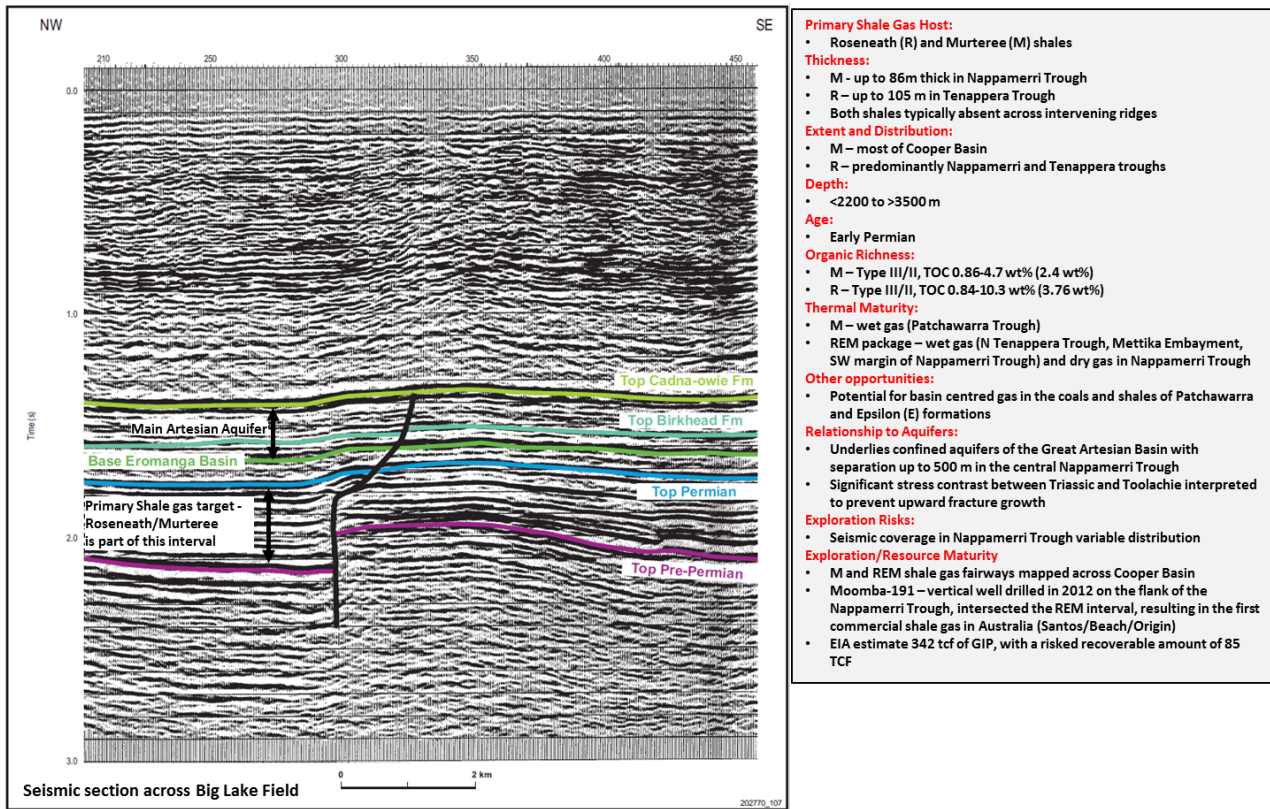


Figure 4: Top: Seismic section across the Big Lake Field. **Bottom:** Wells cross-section across the central Nappamerri Trough in the Cooper Basin. **Green** shading highlights the Roseneath-Epsilon-Murteree succession and **yellow** shading the deepest aquifer interval in the overlying Eromanga Basin/Great Artesian Basin. (Modified after Hillis et al., 2001).



McArthur Basin

The McArthur Basin is a large, Precambrian-aged, intracratonic basin located in the northern Australia on the Northern Territory-Queensland border. There are a number of deeper sub-basins within the McArthur Basin with most important being the Beetaloo Sub-basin (Silverman et al., 2005).

There are a number of potential shale gas resources in the Upper Roper Group, the most important of which is the Velkerri Formation. Within the Velkerri Formation, the middle Velkerri Formation comprises three main highly organic-rich intervals that extend under cover across large parts of the greater McArthur Basin (Figure 5 and 6).

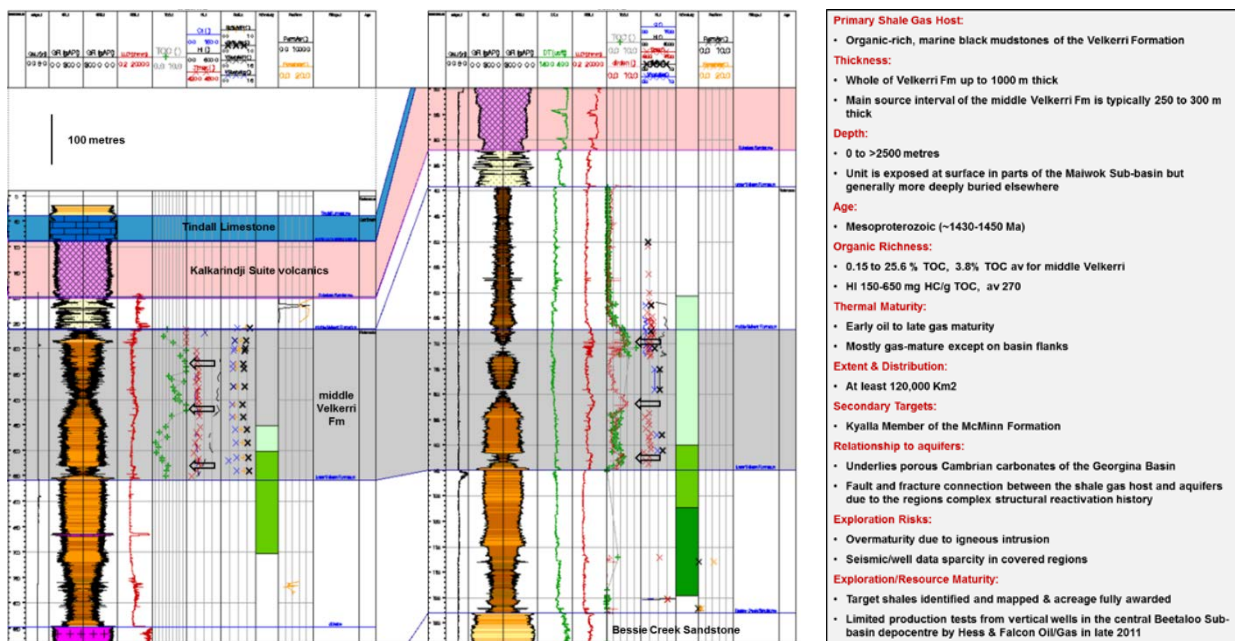


Figure 5: Wells information of prospective shale gas resources in the McArthur Basin (FROGTECH 2013).

The formation has attained suitable thermal maturation for the generation of both oil and gas. Well tests and hydrocarbon show data indicate that the formation is productive and contains a large shale gas resource. The unit also has potential for shale oil around the basin margins. The overlying Kyalla marine shale (of the McMinn Formation) also has significant shale-gas and shale-oil potential in the deeper parts of the basin. To the east other Proterozoic depocentres contain slightly older organic-rich intervals with similar unconventional hydrocarbon potential. Some of the other key shale gas targets in the region include the Barney Creek Formation in the Batten Trough and time-equivalent black shales within the Riversleigh Siltstone and Lawn Hill Formation on the Lawn Hill Platform (Silverman et al., 2005).

Although, no studies have looked in detail at the connection between gas shales and aquifers, the relatively low level of structural complexity (Figure 6) suggests that the risk of fracking affecting groundwater is low.

Although there are few groundwater users (groundwater abstraction ~9 GL/yr) there may be localised effects on environmental and human users, from abstracting water for fracking. Based on the sustainable groundwater yield the estimated groundwater footprint is about 6 times larger than the shale gas footprint (NLWRA, 2001 also see Table 2 for explanation of method).

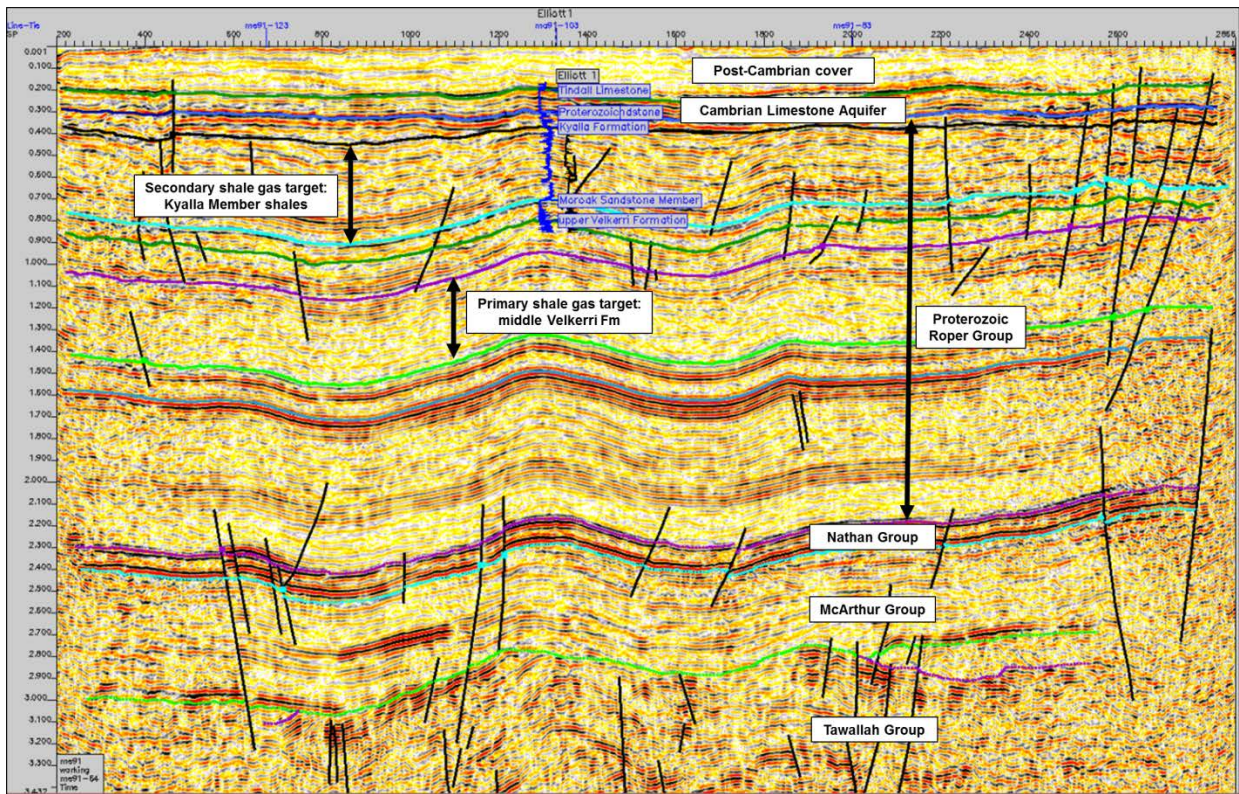


Figure 6: Example interpreted seismic section in the McArthur Basin (FROGTECH, 2013).



Otway Basin

The Otway Basin is an extensional- transitional basin off the southeast coast of South Australia, Victoria and Tasmania. It has been exploited as a conventional oil and gas basin since the 1950s. Basement depth could exceed 10,000 metres. There are a number of potential shale gas resources in the Otway Basin including the Sawpit Shale and the Casterton Formation (Jorand et al., 2010).

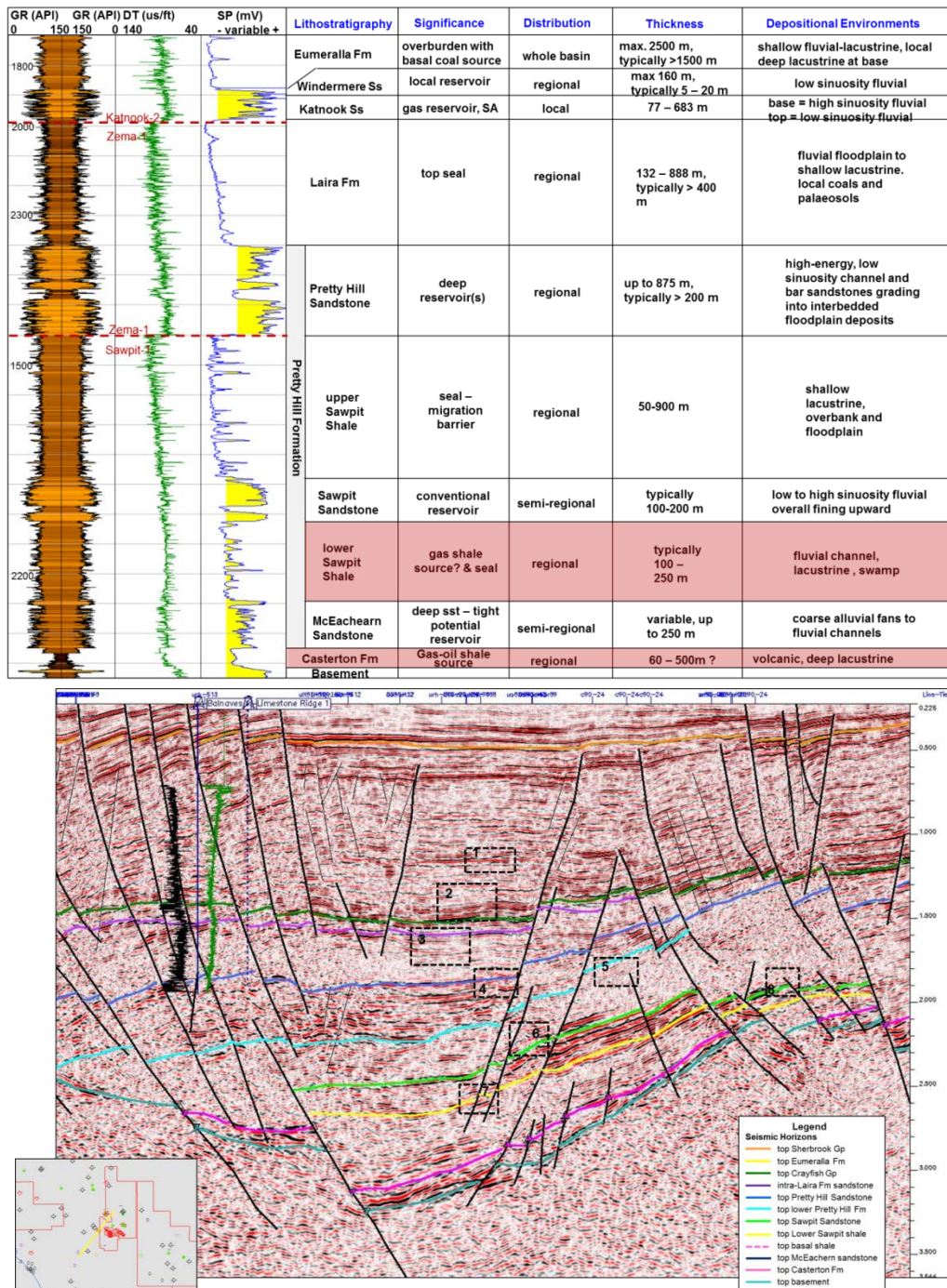


Figure 7: Top: Description of shale gas resources of the Otway Basin in **red**. **Bottom:** an example of the complex faulting and depositional relationship as shown in a seismic cross section (FROGTECH 2013).



As seen in Figure 7, the Otway Basin is structurally complex which may increase the potential for fluid flow between gas shales and other units including aquifers. The Otway Basin has multiple users ranging from conventional oil and gas, carbon capture and storage, groundwater (unconfined and confined), hot sedimentary aquifer (geothermal), coal seam gas and shale gas. How these different users will interact depends on the volume of fluid extracted (or stored), the location of other users both laterally and vertically and the structural and lithological characteristics (http://www.pir.sa.gov.au/petroleum/access_to_data/petroleum_publications/otway_basin/otway_basin_hot_sedimentary_aquifers_and_seebase_tm_project).

Groundwater use is higher than any other likely shale gas basin in Australia, but groundwater recharge is also much higher (NLWRA, 2001). The estimated groundwater footprint (to obtain water for fracking) is half the shale gas footprint (see Table 2 for explanation of method).

What are gas shales?

Shales are a sedimentary rock composed of clay-sized particles that were deposited in a low energy environment such as tidal flats or deep water basins. Depending on the location, a significant amount of organic material from algae, plants and animals may also be deposited. It is these materials which form the source of organic materials exploited in oil and gas shales. These sediments are then lithified into thin layers called shale (USDOE, 2009).

Until recently shales with a high organic content were thought of as primarily as potential source rocks for conventional oil and gas. However, with the development of horizontal drilling and fracking, new reserves of oil and gas became available for exploitation.

Not all shale deposits are suitable for shale gas, and even within a shale unit, there are sweetspots/fairways where organic content and production is concentrated. These sweetspots may make up only 10% of the area of gas shale but they may contain 80% of the gas production.

The ideal gas shale has:

- Total Organic Carbon (TOC) > 2%;
- Kerogen types I, II, IIs;
- Vitrinite reflectance (Ro) > 1.1;
- Net thickness > 15 metres;
- Suitable mineralogy to form effective porosity;
- Source of gas is thermogenic (may be determined from isotopic signature);
- Hydrogen Index (HI) > 250 mg/g;
- High gamma ray values in shale;
- Gas shale porosity > 4%
- Depth > 1500 metres;
- Overpressured; and
- Not intensely structured (after Charpentier and Cook, 2011 and Haley, 2009).



Lessons Learned from Coal Seam Gas

Managing the effects of coal seam gas (CSG) in Australia is an evolving and ongoing process. The Commonwealth government has set up the Office of Water Sciences and the Expert Panel for Major Coal Seam Gas projects to manage, understand, build and implement the knowledge base necessary for handling CSG in Australia. In addition, work on understanding and managing CSG and water is also going on at the state level.

The techniques and methods being developed for will also be useful for shale gas production, although the greater depth of shale gas production will necessitate an even greater understanding of the tectono-stratigraphic framework (see Tectono-stratigraphic framework box).

The major issues of CSG and shallow water resources (after <http://www.rdaiwm.org.au/wp-content/uploads/2012/06/Coal-Seam-Gas-Issues-for-Consideration.pdf>) and how they relate to shale gas are:

- Contamination of aquifers and surface waters by coproduced waters: Contamination may come from leakage of coproduced water (typically brackish) due to interaquifer flow, well failure, accidents on site from coproduced water and fracking fluid, and disposal of brines.
 - Contamination of aquifers via interaquifer flow is probably low in shale gas production, but well failure accidents and disposal are all potential problems.
- Changes in groundwater flow regime both natural and induced: CSG production involves the coproduction of large volumes of water. This may result in changes to the hydraulic balance of a system resulting in changes in groundwater flow direction, reduction in hydraulic head/potentiometric surface, reduced water availability for other users and deterioration of water quality. The location and magnitude of these changes within the subsurface are controlled by the presence of faults, fractures, heterogeneities within units and other discontinuities.

Generally, because of the reduction of pressure, groundwater flow will be towards coal seams from surrounding aquifers.

The Namoi Catchment Water Study (Schlumberger, 2012) modelled the effects on groundwater and surface water resources due to coal mining and CSG production. It found that extensive regional scale impacts on water resources is unlikely, although there might be localised effects on groundwater levels in fracture rock aquifers.

- The volume of water produced during shale gas production is an order of magnitude less than CSG production. In addition, shales tend to act as aquitards or aquicludes and thus act to isolate groundwater flow systems. Proper management of shale gas production including reducing fracture growth near aquifers and modelling the effects of fracking will help to minimise the impact on potable aquifers.

In Australia, the primary effects of shale gas on groundwater resources will likely be from abstraction of water for use in fracking. This is because most shale gas basins are located in semi-arid and arid Australia which have limited water availability. See "Source of fracking water."

- Brine management: Cover how to handle and store coproduced water. In CSG, this is primarily temporary storage of large volumes of water usually onsite. There are a variety of reuse and recycle options to treat coproduced water such as irrigation, stock water, aquifer recharge, aquaculture, and industrial uses (RPS, 2011).



- The volumes of coproduced water are much less in shale gas, but the quality is generally worse. Salinity may exceed 400,000 mg/L and include a range of potentially harmful elements. Because of the high salinity and the other
- ReInjection of fluids: After treatment or storage, the remaining brine is injected into another unit. Issues include understanding the chemical and hydraulic affected of injecting the brine on aquifer and surrounds.
 - Like CSG (geology permitting), shale gas brines are typically reinjected into another unit for disposal.
- Hydraulic fracturing: Management of chemicals, fracture propagation, reactivity, transport and aquifer interaction.
 - Unlike the majority of CSG production in Australia, shale gas almost always necessitates fracking to stimulate production. The source, transport and management of fracking fluid is an important issue for shale gas.



Geological Risk Factors for Shale Gas

There are a number of geological risk factors which may affect future shale gas development in Australia. While there is some inter-relationship between issues, the major issues are induced seismicity, water management (source of fracking water, protection of potable aquifers, and disposal and reuse of recovered water) and well integrity.

Induced Seismicity

Induced seismicity from (uncontrolled) fracture propagation is a potential risk of shale gas production (Healy, 2012). Fracking was first developed in the early 1900s but was only applied commercially in the 1940s (Cooley and Donnelly, 2012). The stimulated fractures may extend up to several hundred meters into the rock (Royal Society and Royal Academy of Engineering, 2012), as demonstrated by Davies et al., (2012) who reported maximum upward propagation of fractures of ~588m and ~536m in the Barnett and Marcellus Shales in the US, respectively (Figure 9).

Because of the potential health and environmental risks due to induced seismicity from fracking, a blanket ban on hydraulic fracturing has been imposed in France and Bulgaria (<http://www.guardian.co.uk/world/2012/feb/14/bulgaria-bans-shale-gas-exploration>).

However, the risk of induced seismicity is not unique to shale gas development. Seismic events may also be triggered by mining, conventional oil and gas developments, dams, geothermal power, carbon capture and storage, water injection for disposal. As of 2012, only 2 examples of induced seismicity from fracking had been found in the US (NAS, 2012).

There have been concerns in the UK regarding induced seismicity and fracking. These occurred after hydraulic fracturing in the Lancashire region and from the Preese Hall well in the Blackpool area where there were a series of induced earthquakes between April and June 2011, however the earthquakes only reached a maximum magnitude of 2.4 M_L (Figure 8). Based on the UK experience in Lancashire, Green et al., 2012 recommends a trigger level of 0.5 M_L to cease operations.

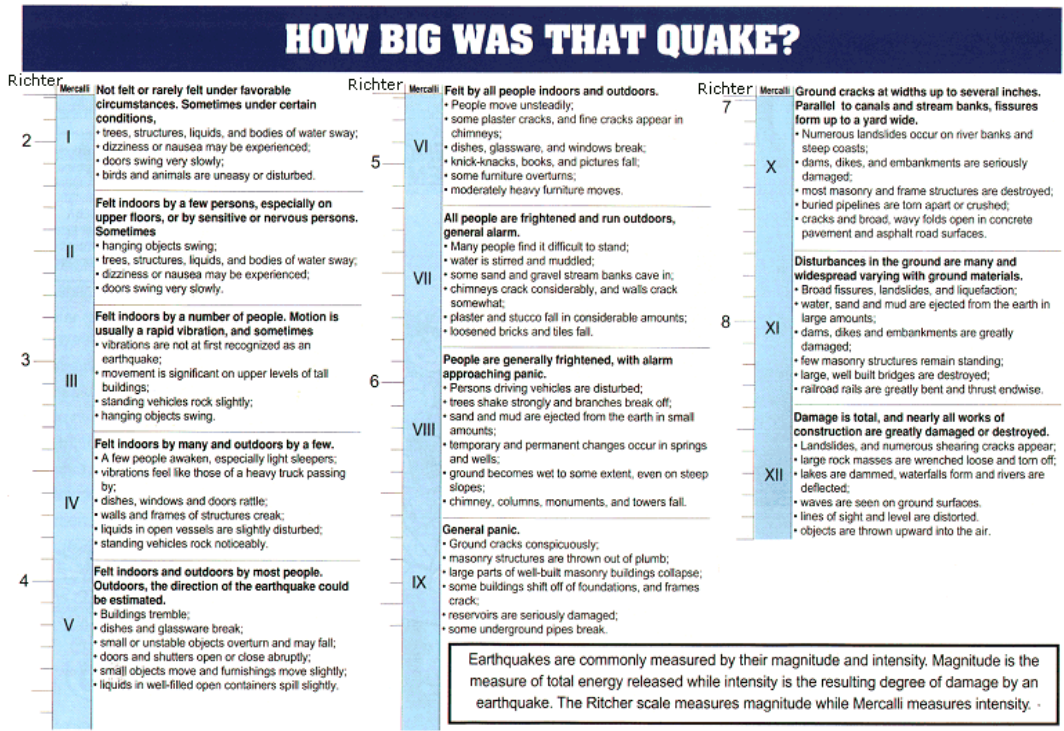


Figure 8: Magnitude of earthquakes and their effects from <http://www.erh.noaa.gov/cae/scale.htm>.

In the UK, coal mining is responsible for about half of all seismicity in the last century. Tremors are still felt occasionally in nearly every coal field in the UK associated with post-mining hydrogeologic recovery and mine flooding, particularly in the Carboniferous formations where shale gas is also being explored (Styles and Baptie, 2011).

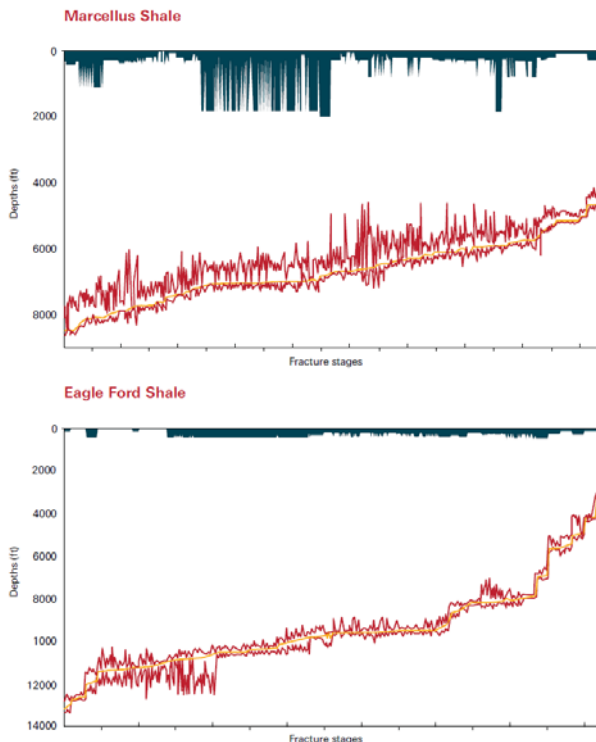


Figure 9: Depth of fracking treatment (yellow), vertical fracture growth (red) compared to depth of groundwater resources (blue) from (Royal Society and Royal Academy of Engineering, 2012).

In the US, the Eola Field, Garvin County in South-Central Oklahoma more than 50 earthquakes were detected on January 18, 2011, with 43 large enough to locate the epicentres. These earthquakes were associated with an active fracking project being conducted in a nearby well. Studies and investigations have subsequently showed that there was a clear correlation between injection and seismicity although subsequent injections at shallower depths had no associated seismicity. The measure earthquake epicentres were <5km from the wells and occurred at or near injection depths (Holland, 2011).

Other notable US and global case examples of induced seismicity from fluid injection (although not fracking) include Rocky Mountain Arsenal (Hsieh and Bredehoeft, 1981), Rangely, Colorado (Raleigh et al., 1972; Raleigh et al., 1976), Paradox Valley, Colorado (Ake et al., 2005) and the KTB Deep Well in Germany (Jost et al., 1995; Baisch et al., 2002). Enhanced geothermal systems with clear correlations between injection



and earthquakes include Frenton Hill, New Mexico (Fehler et al., 1998), Basel, Switzerland (Deichmann and Giardini, 2009), Cooper Basin, Australia (Baisch et al., 2006) and Soultz, France (Horalek et al., 2010, Holland, 2011).

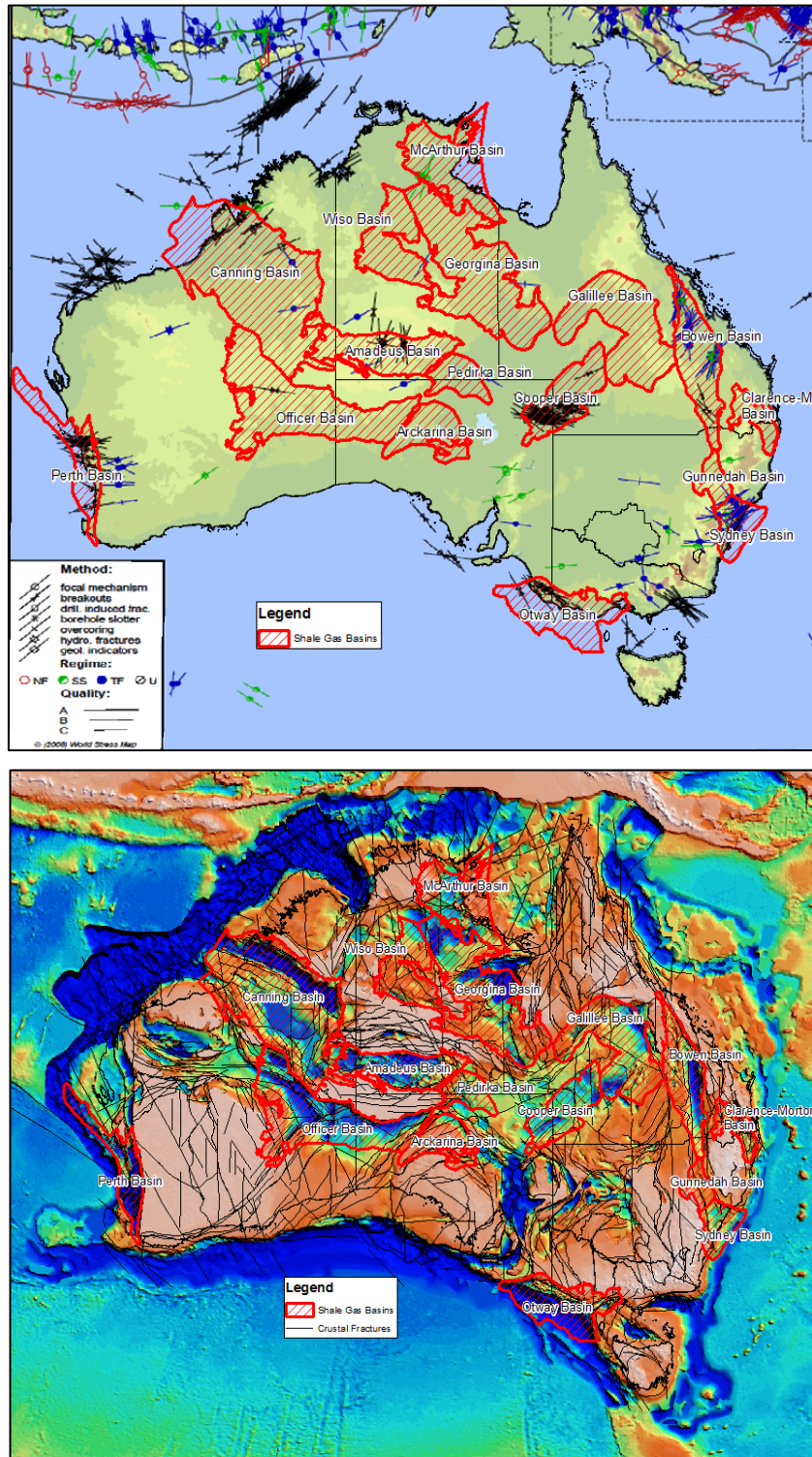


Figure 10: Top: Stress map of Australia with shale gas basins (after World Stress Map, 2008; <http://dc-app3-14.gfz-potsdam.de>). Bottom: Crustal fractures compared to shale gas basins modified from (Geoscience Australia and BREE, 2012, and FROGTECH, 2013).



Australian experience

Reports of anthropogenic-induced seismicity in Australia have largely been documented around geothermal power development and generation and also the construction of dams and reservoirs. Geoscientists in Australia are aware of the risks of induced seismicity from fracking in shale gas exploration. Fracking is currently occurring in the CSG industry in Australia with no reports of induced seismicity.

Geothermal power development in Australia also involves hydraulic fracturing. In 2003, a hydrofracturing experiment by Geodynamics Ltd in the basement beneath the Cooper Basin resulted in over 27,000¹ small induced earthquakes with most < 1.0 M_L. Because of the depth of the fracturing (~4.25 kilometres) even the largest event (3.0 M_L) would only be felt within 5-6 kilometres of the well. As of 2008, they have the most advanced GPD projects in Australia with 3 geothermal wells drilled in the Cooper basin with a 4th on the way as well as a complete induced seismicity dataset from an Australian geothermal development (GA, 2012).

Australia also has a higher than world average occurrence of dams and reservoir-induced earthquakes. Large reservoirs may trigger seismicity either by the weight of the water changing the underlying stress fields or increasing groundwater pore pressure which lowers the stress threshold required for earthquake activity. Induced seismicity has been reported at several Australian reservoirs e.g. Talbingo, Thomson, Pindari, Eucumbene, Warragamba, Gordon and Argyle Dams. Induced seismicity has also been observed in over 100 dams around the world, notably in China, Africa, Brazil and India (Gibson, 2008).

During the mid-2000s, hydraulic fracturing was only carried out in the conventional oil and gas wells of the Cooper Basin. As of 2012, fracking is actively being carried out in the Canning and Perth Basins. However, an appropriate knowledge base has yet to be developed to understand fracture propagation in Australian basins.

There is some stress data for Australia (Figure 10), but except in a few areas it is at yet at a coarse scale (World Stress Data, 2008).

Future Considerations

Based on world experience of fracking for shale gas, the following suggestions for lowering risk come from Davis et al., (2012), Green et al., (2012), NAS (2012), Royal Society and Royal Academy of Engineering (2012) and Holland (2011).

To minimise the risks associated with induced seismicity.

- Develop the necessary scientific background on seismicity and structural geology, preferably led by an independent agency such as Geoscience Australia or CSIRO. Such activities include:
 - Mapping and characterising stresses, faults including orientations and strike slip tendencies.
 - Mapping the direction of bedding planes within shales.
 - Building ground motion prediction models for affected regions.
- Establish a traffic light control system for responding to an instance of induced seismicity. Components of a traffic light control system include:

¹ The large number of earthquakes is partly due to number and sensitivity of the instruments employed by Geodynamics rather than being an especially dangerous event.



- Monitoring seismicity before, during and after fracking.
- Establishing action protocols in advance.
- Developing an Australian appropriate seismicity model for seismicity. Until such a model is developed, Australia adopts world best practice trigger levels to manage seismicity caused by fracking and fluid injection such as 0.5 M_L used by the United Kingdom (Green at al. 2012).
- Developing the ability to alter plans on-the-fly such as changes to injection rates.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Publicising the processes and techniques to be employed in area.
 - Publicising action protocols and risk reduction plan in the event seismic trigger values are reached.
 - Reporting seismic incidents related to well construction, operation and abandonment.
 - Explaining the goals and expectations of project.
- Develop a checklist to determine if fracking and fluid injection might cause seismicity such as developed by NAS (2012). Example checklist questions include:
 - Are large earthquakes (M_L) known in the region?
 - Are earthquakes known near the fracking site?
 - Is the rate of activity near the fracking site high?
 - Are faults mapped within 20 km of site?
 - Are these faults active?
 - Is the site near tectonically active features?
 - Do stress measurements in the region suggest rock is close to failure?
 - Are proposed fracking practices sufficient for failure?
 - If fracking has been ongoing at the site, is it correlated with earthquakes?
 - Are nearby fracking wells associated with earthquakes?
- Develop a set of best practice fracking methods such as minimising pressure changes at depth.

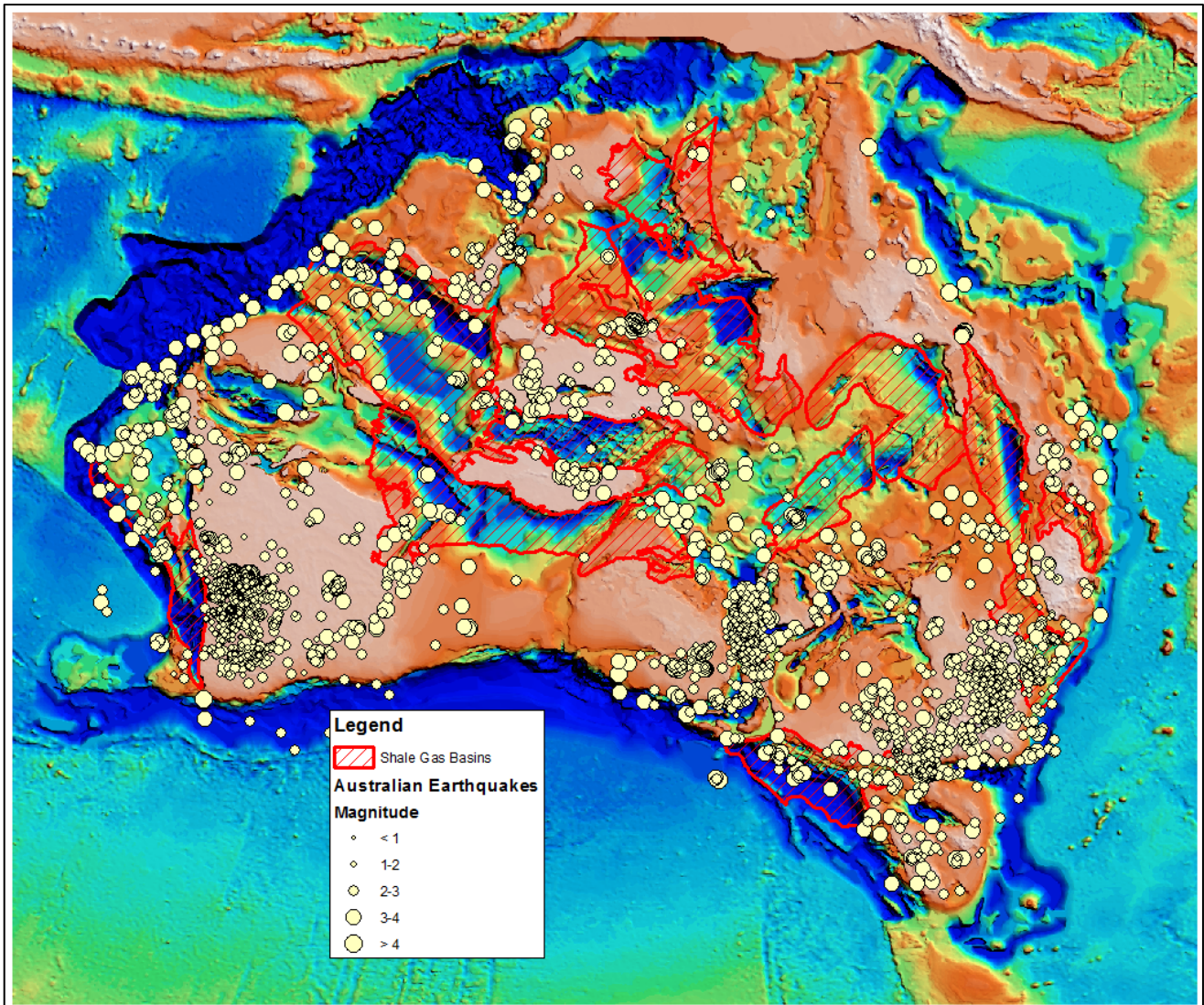


Figure 11: Shale gas basins and the locations of earthquakes in Australia from 1955-present (<http://www.ga.gov.au/earthquakes/searchQuake.do>) modified from (Geoscience Australia and BREE, 2012 and OZ SEEBASE™).



Water Management

Managing water in a safe and sustainable manner is a key issue facing the shale gas industry in Australia. There are at least four components of water management for shale gas: the source of water used in fracking, protecting potable aquifers, reuse and disposal of produced water and aquifer interference/reduced water availability.

Source of fracking water

The primary component of the hydraulic fracturing or “fracking” process is water (see Fracking Box). The actual volume of water needed to hydraulically fracture a well, depends on local geological conditions such as depth, porosity, length and number of horizontal strings and existing fractures. It may vary both within and between geological basins (Nicot and Scanlon, 2012). Median water use for a range of shale gas plays in the US may be seen in Table 1.

In the US, depending on location and price, fracking water comes from both surface and groundwater sources.

Play	Volume (ML)
Barnett, Texas ¹	10.6
Haynesville, Texas ¹	21.5
Eagleford, Texas ¹	16.5
Marcellus, PA ²	17.1

¹ Nicot and Scanlon (2012)

² Beauduy (2011)

Table 1: Median volume of water used for fracking per well.

Water quality is also important part of the fracking process, with either fresh or brackish water preferred because of the potential for highly saline water to produce scale and affect the efficacy of fracking chemicals (Godsey, 2011). However, as fracking methods continue to improve the use of saline and recycled water and even waterless methods of fracking using nitrogen have been developed, but they are currently a higher cost alternative (Burke, 2011).

Box: Fracking

'Fracking' (also spelled fraccing) is drilling industry slang term for hydraulic fracturing of a reservoir/aquifer to increase the rate of fluid flow. The process is generally used by the natural gas industry although other industries that abstract geofluids (oil, gas, water, geothermal etc.) may also use the process.

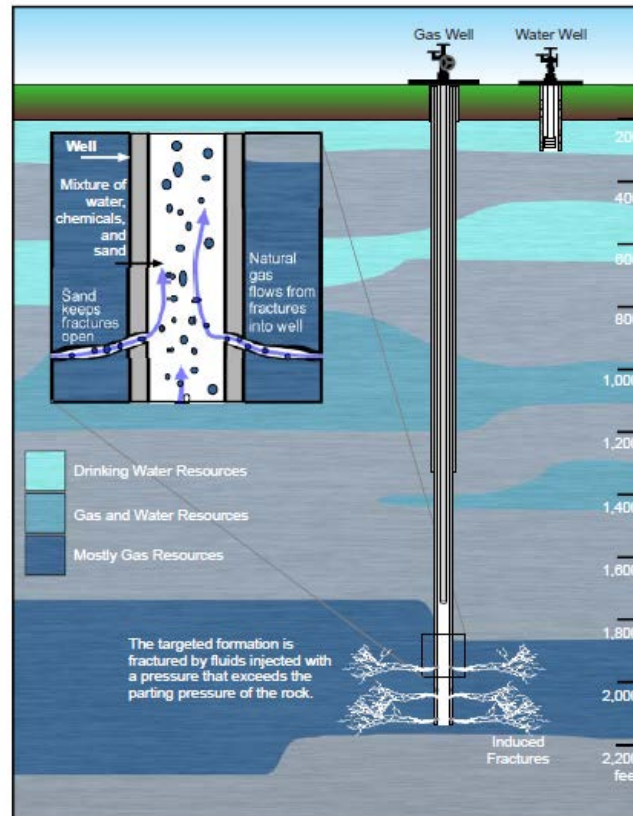


Figure 12: Typical groundwater depth compared to shale gas well depth (USEPA, 2011).

What is Fracking?

Fracking occurs by injecting a slurry of water, sand and specialised chemicals (the formula varies and it is usually proprietary) under high pressure into a well/bore. The water is used to fracture the rock unit and then the sand is used to keep the fractures open. The additional chemicals are used to reduce friction and surface tension, kill bacteria, remove scale and to inhibit corrosion (Figure 12).

Why frack?

Some rocks such as shale and some sandstones may contain gas and other fluids but have such low permeability (0.01 to 0.00001 mD) that it is difficult to extract any fluid from them (USDOE, 2009). Fracturing the rock may increase the permeability by 4-5 orders of magnitude (or more) thereby allowing producers to economically collect gas or other fluids.

Australian experience

Because shale gas production in Australia has just started, the volume of water needed to frack Australian shales is not yet understood. However compared to coal seam gas, the volume of water needed to frack shale gas strata is typically an order of magnitude higher due to greater depths and different geology (Golder Associates, 2010).

Unlike the United States, most of the potential shale gas basins in Australia are located either wholly or partly within the arid zone (Figure 13). This means that groundwater will likely be the sole water resource available to energy companies (unless imported from elsewhere) and that natural

groundwater recharge rates are low. Table 2 shows some conservative estimates of the potential volume of water that may be used for fracking in each basin compared to calculated sustainable yield values and estimated groundwater use. The use of recycled water or waterless methods of fracking will help to reduce the volume of water needed to be extracted for fracking.

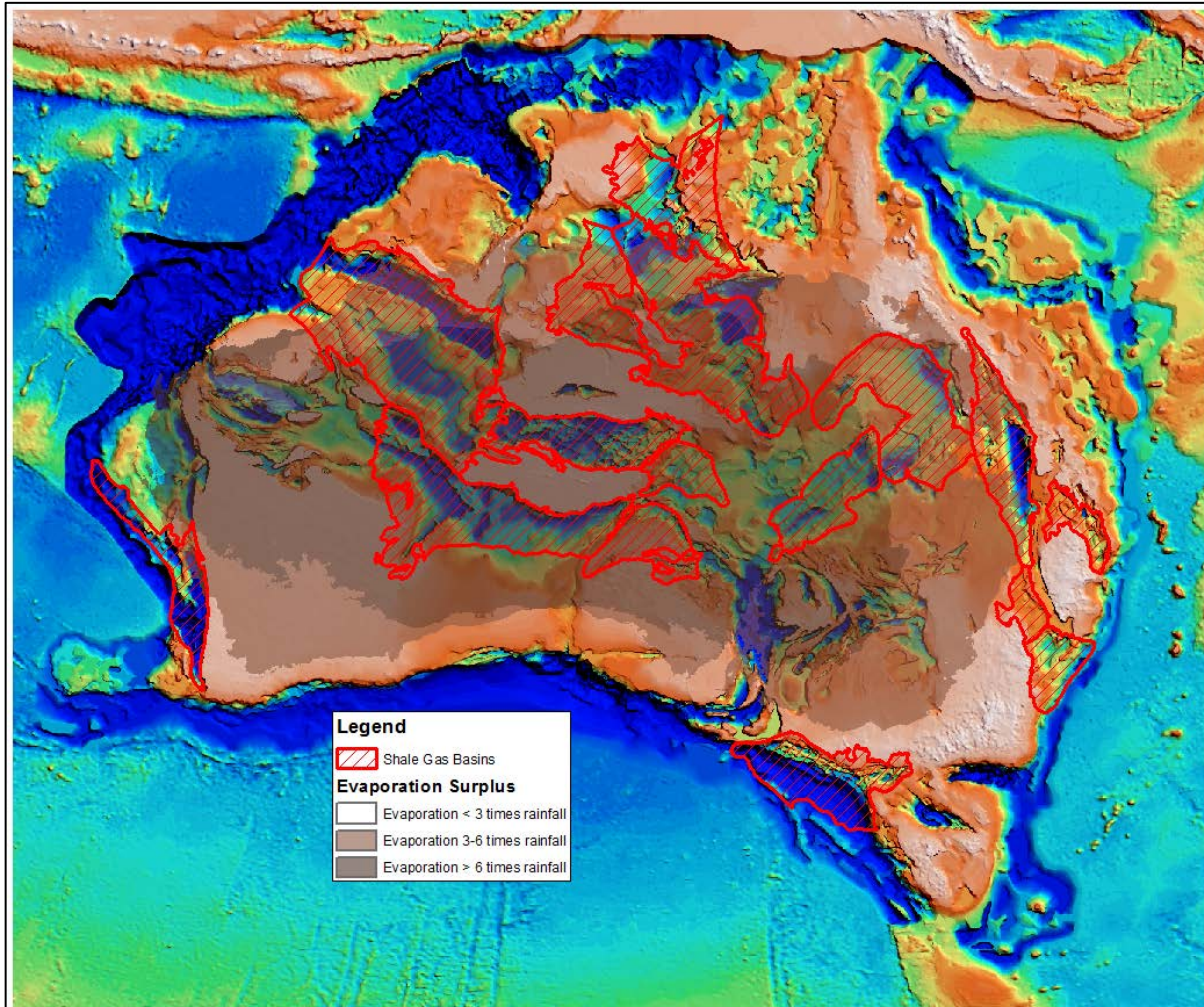


Figure 13: Basins with high shale gas potential over OZ SEEBASE™. Coloured band demonstrates where evaporation is much greater than rainfall. Where evaporation is 3-6 times rainfall is roughly equivalent to the semi-arid regions of Australia and where evaporation is greater than 6 times rainfall conforms to arid Australia. In both areas surface water is rare. Therefore, any water used for fracking will either have to come from groundwater or be imported from elsewhere.

Rainfall (http://www.bom.gov.au/jsp/ncc/climate_averages/rainfall/index.jsp) and evaporation (http://www.bom.gov.au/jsp/ncc/climate_averages/evaporation/index.jsp) from the Bureau of Meteorology. Shale gas basins modified from (Geoscience Australia and BREE, 2012).



Basin	Basin area (km ²)	Number of shale gas wells	Water needed for fracking (GL)	Fracking water per year (GL)	Groundwater sustainable yield (GL/yr)	Groundwater abstraction (GL/yr)	Water footprint compared to gas footprint
Amadeus	162,294	12,679	190.2	7.6	142	14	26
Arckaringa	87,331	6,823	102.3	4.1	12	11	167
Bowen	161,559	12,622	189.3	7.6	224	101	17
Canning	534,046	41,722	625.8	25.0	834	22	15
Clarence-Morton	45,861	3,583	53.7	2.1	705	168	1.5
Cooper	121,382	9,483	142.2	5.7	20	29	139
Galilee	337,973	26,404	396.1	15.8	106	99	73
Georgina	362,638	28,331	425.0	17.0	241	64	34
McArthur	198,480	15,506	232.6	9.3	749	9	6
Officer	333,657	26,067	391.0	15.6	249	<1	31
Otway (onshore)	44,105	3,446	51.7	2.1	1,998	238	0.5
Perth	186,678	14,584	218.8	8.8	1,609	677	3
Sydney	60,630	4,737	71.1	2.8	896	79	2
Wiso	138,586	10,827	162.4	6.5	106	4	30

Table 2: Shale gas basins in Australia showing the potential number of wells (assuming well space of 800 metres and fairways making up 5% of the basin). The estimated volume of water needed to frack these wells assumes 15 ML/well. The volume of fracking water per year assumes a 25 year life span of the field.

Groundwater sustainable yield and groundwater abstraction values from NLWRA (2001) and AWR2005 (<http://www.water.gov.au/>). Shale gas basin boundaries were used to clip all groundwater management units (GMUs) within the shale gas basin and a *pro rata* estimate of sustainable yield made based on NLWRA 2001. Water footprint is the factor by which the area of land needed to sustainably withdraw 15 ML of water for fracking exceeds the area of land (640,000 m²) covered by each gas well.



Box: Quality of fracking fluid and formation water

Shales generally have low permeability (although high porosity) and are generally considered to be a barrier to groundwater flow (aquicard). Therefore, unlike coal seam gas, shale gas production does not usually involve large volumes of coproduced water. However, during production and initial flowback from the fracking process from 30-70% of water injected during fracking is recovered (USDOE, 2009).

In addition to the fracking fluid the recovered water is also mixed with formation water trapped in shale pores. This water (Table 3) is usually highly saline and may contain a range of harmful elements such as naturally occurring radioactive material (NORM), barium, trace elements and volatile organic compounds (USEPA, 2011).

Chemical	Potential values in formation waters/fracking fluids	Australian Drinking Water Guidelines (2004)
BTEX (benzene, toluene, ethylbenzene and xylene) ²	Impossible to determine each company and each area has its own proprietary mix. BTEX chemicals are found in diesel, petroleum raffinates, naphthas etc.	Benzene: < 0.0001 mg/L Toluene: 0.025 mg/L Ethylbenzene: 0.003 mg/L Xylene: 0.02 mg/L
Salinity (generally NaCl) ⁴	Formation waters: > 150,000 mg/L	1000 mg/L
Methane ³	Up to 70 mg/L	None, USDI trigger levels 10-28 mg/L
NORM (naturally occurring radioactive material) ¹	Gross alpha: >7.4 x 10 ¹¹ Bq/L Gross beta: >7.4 x 10 ¹⁰ Bq/L	Gross alpha: 0.5 Bq/L Gross beta: 0.5 Bq/L
Barium ⁴	> 300 mg/L	0.7 mg/L

¹ Williams (2010)

² DiGiulio et al., 2011: Values of benzene found in groundwater exceeded guidelines by 49 times.

³ Chapman et al., (2012)

⁴ USGS (2006)

Table 3: Selected contaminants in fracking fluids and shale brines compared to Australian Drinking Water Guidelines.

Fracking fluid

The fluid (Figure 14) used in fracking generally consists of over 95% water, 2-3% propan (sand). However, it the remaining portion of the cocktail that tends to cause concern with fracking opponents. As seen in Figure 3, the exact proportions of these chemicals vary both between companies and even within a company, as they are specially formulated with for local conditions. Typically the additives to fracking fluid contain:

- friction reducers: to aid fracking fluid and sand to more easily enter fractures, typically a petroleum distillate;
- acids: to remove scale/iron oxides and clean well bore, typically HCl;
- gel: to help suspend sand, typically guar gum or hydroxyethyl cellulose;
- scale and iron inhibitor: typically citric acid and ethylene glycol;
- crosslinker: to maintain fluid viscosity as temperature increases, typically borate salts;
- biocides: to limit the growth of iron reducing bacteria, typically a proprietary organic chemical;
- surfactants: to aid water recovery by breaking surface tension of water, typically ethanol and naphthalenes; and
- corrosion inhibitors: to prevent acid from damaging well casing, typically ammonium and other salts (USDOE, 2009 and http://www.halliburton.com/public/projects/pubsdata/Hydraulic_Fracturing/fluids_disclosure.html).

The makeup of fracking fluid is constantly changing due to regulatory changes and in response to innovation seeking better gas recovery. Gels and foams being used to reduce water use and there are even completely waterless methods of fracking using nitrogen and other gasses.

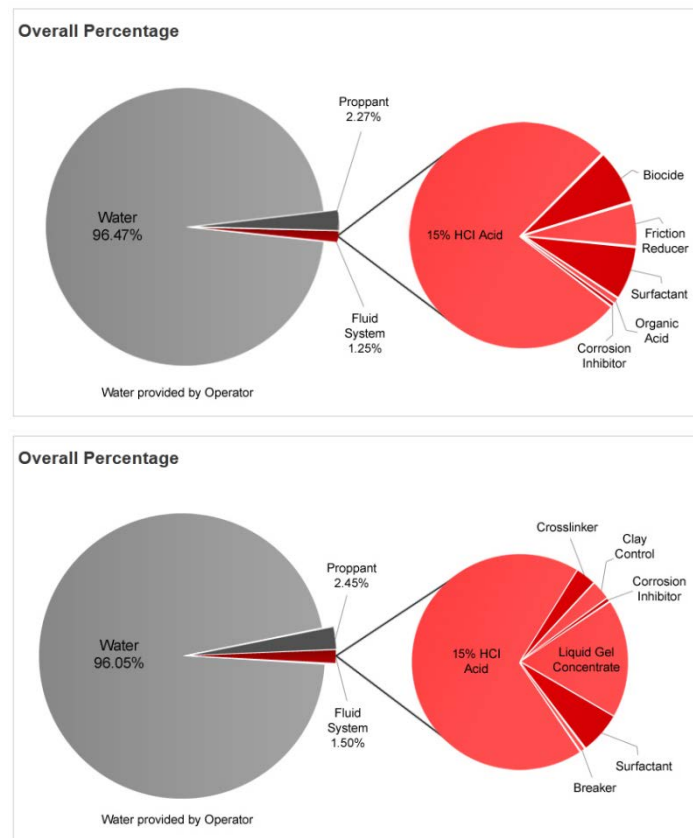


Figure 14: Examples of fracking formulas from the same company (Halliburton) in different location and for different purposes. Such variety makes it impossible to say make definitive statements of the composition of fracking fluids. Upper image consists of Utah WaterFrac Formulation and the lower is West Texas WaterFrac™ XL Formulation (http://www.halliburton.com/public/projects/pubsdata/Hydraulic_Fracturing/fluids_disclosure.html).

Formation water

Shales may contain large volumes of water trapped in pores, although the low permeability of shales means that the water is trapped. As a result, the shale water may be highly saline including high concentration of manganese, strontium, barium, iron and naturally occurring radioactive material which is sometimes referred to as NORM (Williams 2010).

The brine derived from each shale will vary depending on depositional and burial history. Understanding the composition of gas shale brines is vital for managing the risks associated with shale gas production (USGS 2006).

Contamination of potable aquifers

The potential contamination of potable aquifers with both fracking chemicals and formation waters is a major issue of community concern. The documentary “Gasland” has become a rallying point for anti-fracking activists especially the scenes of tap water being lit on fire (Figure 15).

In this debate, it can be difficult to distinguish fact from fiction as both opponents and proponents make claims and counter claims supporting their views. In reality, scientists, operators and regulators are only just beginning to understand the long term effects of fracking on the environment. More information is needed on groundwater baselines, groundwater processes at depth and the tectono-stratigraphic framework. This information in turn, could be fed into comprehensive groundwater models in order to predict and manage risks.



Figure 15: Still image of Mike Markham lighting his tap water on fire from the documentary “Gasland” by Josh Fox.

There are numerous anecdotal examples of water contamination causing health problems, animal deaths and food contamination (<http://www.thenation.com/article/171504/fracking-our-food-supply>). Many of these examples are due to poor handling of produced water through spills and illegal disposal, not necessarily through failures of the fracking process.

There have also been some high profile examples of groundwater contamination due to fracking, the most prominent of which involved a case of chemical contamination (BTEX, other organics and methane) in groundwater Pavillion, Wyoming. The suspected source of contamination are two conventional gas wells (not shale gas) in the Wind River Basin which had been fracked in order to increase production. The hydraulic fracturing occurred within 372 metres of the surface, while domestic groundwater bores in the area are screened as deep as 244 below the surface (DiGiulio et al., 2012).

The ultimate pathway of contamination in Pavillion has not been fully determined, but it is important to note that apart from two production wells, none of the gas wells are cased below the level of local groundwater system (DiGiulio et al., 2012).

Because of its flammability, methane is one of the more visual indicators of contamination. However, methane may also be found naturally in groundwater due to either microbial action or from slow accumulation from deeper gas bearing strata over time. Indeed the Moomba Gas field in South Australia was partially developed from the presence of gas shows in the Great Artesian Basin aquifers (Cotton et al., 2006). The original source of methane may be distinguished by analysing the isotopic signature of the gas.

Shales naturally have inherent low permeability (Figure 16) and will generally act as aquitards or aquicludes limiting groundwater flow. However, faults, fractures, and lithological heterogeneities in the shale and overlying and underlying units may act as preferential groundwater pathways (Myers, 2012).

Because of shale’s inherent low permeability and the depth of most shale resources (1000-3000 metres) it is generally thought that there is little to no connection between deep brines associated with shales and shallow drinking water. However Warner et al. (2012), found evidence of mixing of brines and shallow groundwater through advective flow via faults and fractures. This mixing was independent of the presence of fracking in the area.

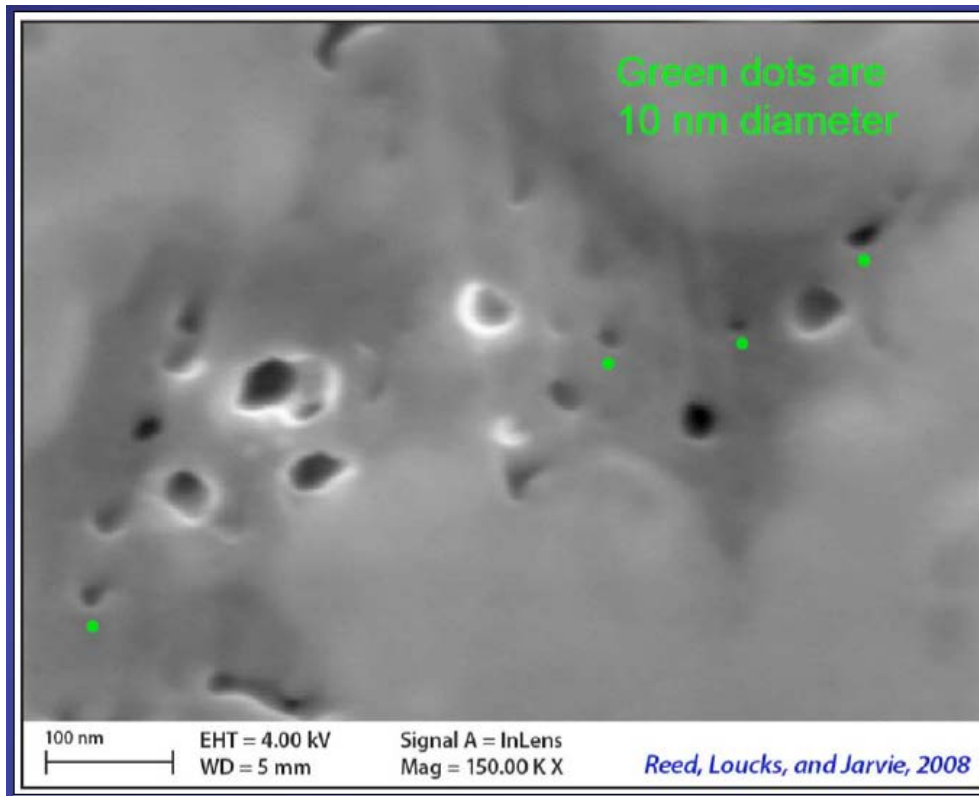
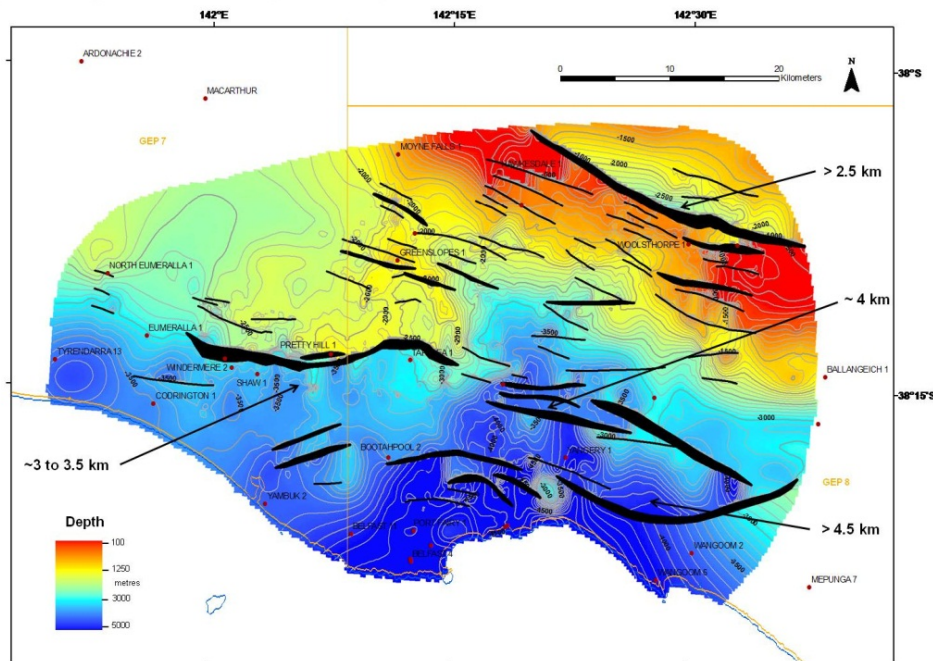


Figure 16: Electron microscopy of nanopores, which contain methane in a shale
(http://www.dnr.state.oh.us/Portals/10/Energy/Marcellus/The_Marcellus_Shale_Play_Wickstrom_and_Perry.pdf)

Box: Tectono-stratigraphic framework

The basis for understanding preferential pathways and deep groundwater resources may come from building the tectono-stratigraphic framework (also called geofabric) supplemented with groundwater samples and monitoring data. The geofabric consists of the stratigraphy, lithology, facies architecture, fault geometry, basement structure and composition, tectonics etc. In other words, anything that could influence or control the movement of geofluids (oil and gas, groundwater, geothermal, carbon etc.) in the subsurface

Top Pretty Hill Ss depth map – central VIC



• PHS aquifer within desirable 2 – 4 km depth range across large areas of Morenda, Warrong, Koroit and Windermere troughs and Tyendarra Embayment

Figure 17: Example of the level of detail in which even deep aquifers (depth ~2.5-5 kilometres) could be mapped. From the Pretty Hill Sandstone, Otway Basin.

http://www.pir.sa.gov.au/petroleum/access_to_data/petroleum_publications/otway_basin/otway_basin_hot_sedimentary_aquifers_and_seabase_tm_project.

The elements of the geofabric may be combined with a groundwater model as multiple scales from the aquifer to lithostratigraphic units to even individual megasequences. The limit depends on the available data, which can always be improved) and the needs of the researchers.

Australian experience

The coal seam gas boom has shown that Australia was ill prepared to manage the rapid expansion of CSG. As shown in Figure 1, the potential size of the shale gas resource is at least 3 times larger than the CSG resource. As a result, the shale gas boom may dwarf the CSG boom.

In addition, to shale gas, most Australian sedimentary basins have multiple users that may affect natural groundwater flow such as mining, conventional oil and gas, CSG, farming and waste disposal. The cumulative effects and interactions of these users, each targeting different parts of the basin, is not understood and is rarely modelled or considered.



The Bioregional Assessment process currently underway by the Commonwealth and state governments is starting to build the necessary knowledge base to manage CSG. A key finding that the process has highlighted is that because of the depth of CSG resources, traditional hydrogeological techniques are not sufficient to understand the full effects of CSG development on the water system. This is largely because, >95% of groundwater bores in Australia are <200 metres deep and so hydrogeologists have focussed on understanding shallow groundwater movement. There are exceptions, such as in the Perth Basin or the Great Artesian Basin, but even these systems are

In most Australian sedimentary basins, knowledge about the relationship between deep aquifers, faults, fractures, and over and underlying gas shales (or coal) is poorly understood. In addition, the internal characteristics of deep aquifer such as permeability, porosity, water quality and groundwater flow direction are also generally not known (FROGTECH, 2009).

New methods combining oil and gas industry tools such as the integration of seismic and non-seismic data to understand reservoir/aquifer characteristics, fault, fractures, depositional and structural history, etc. are needed. The goal is building an integrated model from the basement to the surface of fluid movement in the subsurface. Shale gas resources are even deeper than most CSG resources, so it is even more vital to understand the movement of fluid at depth.

Developing the geofabric and an understanding of fluid movement beneath the subsurface will be an iterative process as more information and the effects of current production are understood.

Disposal of produced water

The production of CSG results in large quantities of co-produced water which primarily originated from within the coal seams and to a lesser extent, from surrounding aquifers. While rarely of suitable quality for direct use, reuse is possible with minimal treatment such as reverse osmosis. The primary issue for CSG coproduced water (at least in Australia) is safe temporary storage of the coproduced water until treatment or disposal.

For shale gas, the fluid recovered after fracking consists of a mixture of brine and fracking fluid. Approximately 30-70% of the fracking fluid injected into the shale is recovered. The non-recovered fracking fluid is trapped within macropores, micropores and fractures within the shale (USDOE, 2009).

Recovered fluid usually starts relatively fresh as the water recovered is primarily from the fracking fluid, but it generally increases in salinity over time as the shale brine becomes a larger component of the recovered fluid. Overtime, the fracking fluid will come into equilibrium with the shale brine.

The recovered fluid is generally temporarily stored in sealed dams near the well. From there the water may be treated in a number of different ways including desalination, transport to another location, mixing with surface water or reinjection into a saline aquifer (USDOE, 2009). The option depends on regulations and local conditions.

The key concerns of the recovered fluid are:

- Unregulated release to surface and groundwater resources;
- Leakage from on-site storage ponds;
- Improper pit construction, maintenance and decommissioning;
- Incomplete treatment;
- Spills on-site; and
- Waste water treatment accidents (USEPA, 2011).



Australian experience

Queensland (<http://www.ehp.qld.gov.au/management/coal-seam-gas/pdf/water-management-policy.pdf>) and NSW (<http://haveyoursay.nsw.gov.au/document/show/194>) have developed policies to manage coproduced water during CSG production.

Although, the CSG industries' management of coproduced water may provide some guidance for future shale gas production, the volume of water produced during shale gas is much lower and is generally of poorer quality than that associated with CSG production. Therefore, some of the reuse and recycle options such as irrigation, stock water, aquifer recharge, aquaculture, and industrial uses are probably not suitable for shale gas (RPS, 2011).

Aquifer interference/reduced water availability

In its natural state geofluids (water, oil, gas, CO₂ etc.) in a sedimentary basin is likely to be in some sort of quasi-equilibrium (Figure 18). Changes to the environment such as reduced groundwater recharge, uplift, erosion or changes in stress directions will generally happen slowly enough (although not always) for the geofluids system to adjust so that quasi-equilibrium is maintained (Freeze and Cherry, 1979). For example, geofluids such as oil and gas will migrate over time from depth, which when accumulated in a structural or stratigraphic trap become conventional oil and gas resources.

Human induced changes to conditions within the basin such as from abstraction of water from groundwater bores, landuse changes, mines, CCS, fracking and oil and gas wells for example, occur much more quickly than natural processes. The result is a change from quasi-equilibrium or steady state conditions into transient conditions. Overtime though, a new steady state condition (the time required to reach steady state will depend on geological conditions and the volume of geofluids extracted) will be reached, however the resultant changes in basinal flow conditions may lead to reduced groundwater and surface water availability, migration of contaminants and/or ground subsidence etc. (Freeze and Cherry, 1979).

For example, immediately after fracking, groundwater flow direction will be towards the shale as the decrease that occurred during oil and gas production is re-established. Over next 3-6 years, steady state groundwater conditions will return and within ~10 years, advective diffusion upwards within the basin will begin again. If preferential pathways are stimulated from the fracking process, travel time for contaminants to reach the surface may be reduced by 1-2 orders of magnitude (Myers, 2012).

Managing the effects of changes in steady state conditions necessitates understanding the controls on the movement of geofluids in a basin such as permeability, porosity, thickness, geometry, location and type of fractures and faults, lithology, heatflow, tectonic history etc. that make up the tectono-stratigraphic framework (FROGTECH, 2009).

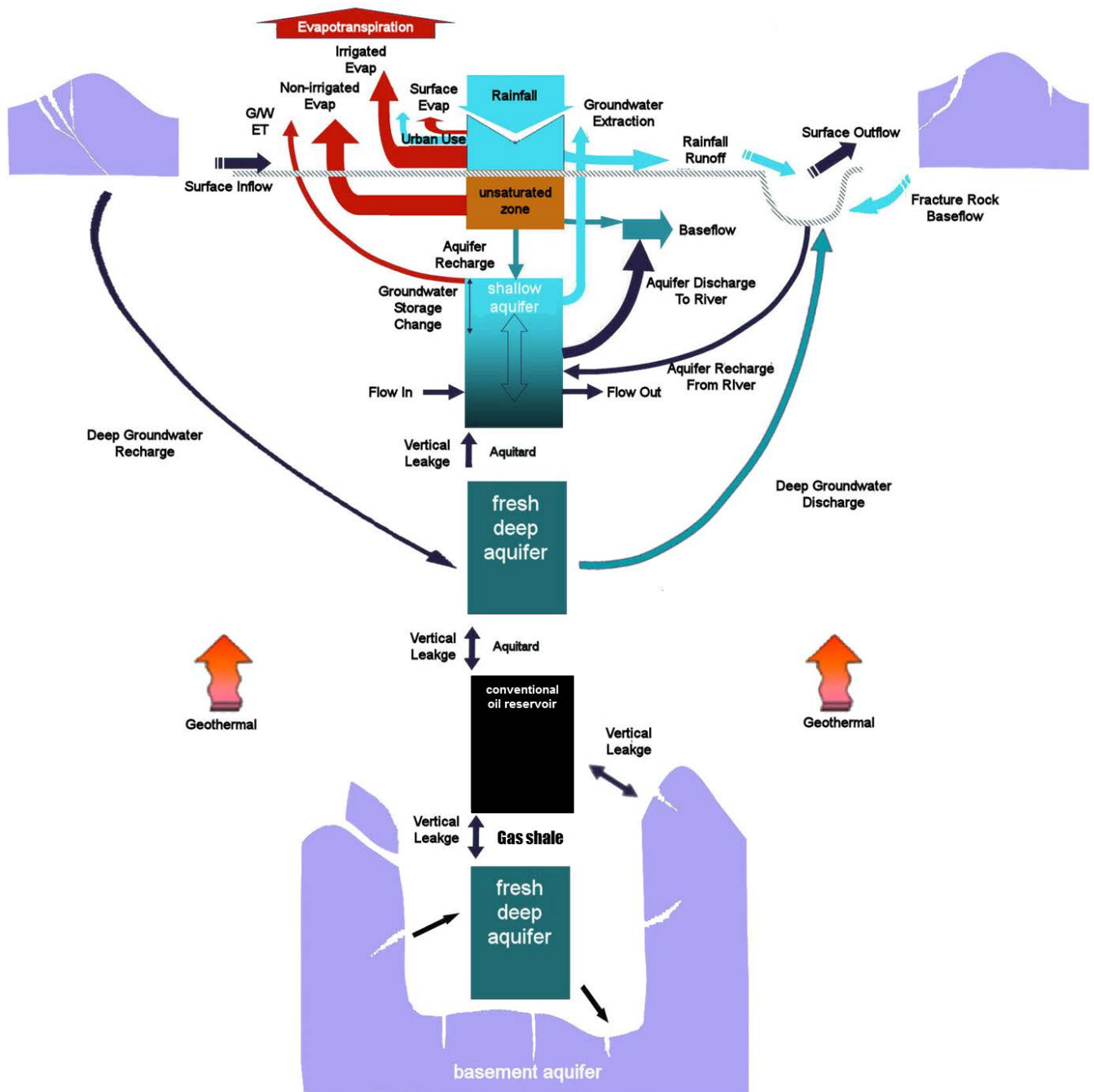


Figure 18: Schematic representation of the interaction between different geofluids within a sedimentary basin. Changes in pressure (due to fluid withdrawal) or changes in hydraulic characteristics such as permeability due to fracking may alter steady state conditions. The box with the dashed outline represents the traditional domain of hydrogeological knowledge. (modified from http://water.gov.au/WaterAvailability/Waterbalanceassessments/index.aspx?Menu=Level1_3_2)

Australian experience

Most states and territories have policies regarding aquifer interference, particularly New South Wales and Queensland.

- New South Wales: <http://www.water.nsw.gov.au/Water-management/Law-and-policy/Key-policies/Aquifer-interference/Aquifer-interference>
- Queensland: <http://www.derm.qld.gov.au/water/declaredareas/regulated-groundwater.html>



According to NSW Water Management Act 2000, aquifer interference is defined as:

- Penetration of an aquifer;
- Interference of water in aquifer;
- Obstruction of water in an aquifer;
- Taking water from an aquifer in the course of carrying out mining or any activity prescribed by the regulations;
- Disposal of water taken from an aquifer in the course of carrying out mining or any activity prescribed by the regulations; and
- Extraction of silica sands and road base material
(<http://www.bhpbilliton.com/home/aboutus/regulatory/Documents/Caroona%20Coal/NSW%20Office%20of%20Water%20Presentation%20on%20Managing%20Aquifer%20Interference%20Activities%20in%20NSW%20-%20October%202012.pdf>).

Aquifer interference is often managed as part of the environmental impact statement (EIS) process, through the use of groundwater models which help predict the effects of a particular action on surrounding aquifers (<http://www.ehp.qld.gov.au/management/impact-assessment/eis-processes/documents/generic-draft-tor.doc>). However even the best groundwater model is an imperfect conceptualisation of groundwater movement and subsurface geology. Typically the deeper the aquifer/resource is within a basin; the less the amount of information is available (Figure 17). As a result groundwater modellers often resort to the use of generalised data that may or may not accurately represent conditions at depth.

As more and more users compete for the resources within a basin, managing and understanding the causes and effects of aquifer interference will become ever more important. Balancing the needs of competing users will necessitate that groundwater models constructed are as realistic as possible. This may be accomplished through the collaboration of hydrogeologists, basin modellers, stratigraphers, structural geologists and geophysicists.

Future Considerations

Based on world experience of fracking for shale gas, the following suggestions for lowering risks associated with water management come from Chapman et al., (2012), Myers (2012), Nicot and Scanlon (2012), Warner et al., (2012), Beauduy (2011), Burke (2011), Godsey (2011), Swistock (2011), USEPA (2011), USDOE (2009), USGS (2006).

To protect groundwater and surface water resources:

- Develop the necessary scientific background preferably led by independent agency such as Geoscience Australia or CSIRO. Such activities include:
 - Building a nationwide database of the geochemistry of shale brines.
 - Understanding natural occurrences of methane in groundwater including the potential source prior to large-scale shale gas development.
 - Building a comprehensive database of groundwater, including time series data and data loggers in key locations.
 - Developing a comprehensive model of the tectono-stratigraphic framework of shale gas basins including mapping faults, fractures, lithology, tops and bottom of key units, stress direction, facies architecture etc. The resulting information may then be made available and serve as the basis for groundwater and other modelling. A key feature being that the model is iteratively expanded as more information becomes available.



- Collaboration between the states and Commonwealth is vital to developing a transparent and consistent regulatory framework for shale gas. Components of the framework include:
 - Developing guidelines on storage, reuse and disposal of fracking fluids across Australia. The goal being to reduce, reuse and recycle produced water where possible.
 - Modifying existing CSG regulations where appropriate, or adopt best practice guidelines for the handling of produced water from other countries.
 - Developing setback rules (minimum distance to other users) to protect other groundwater users (including groundwater dependent ecosystems) and surface water resources.
 - Developing minimum values for vertical and horizontal separation of shale gas resources from potable aquifers based on best practice.
 - Considering the banning chemicals that pose a risk to public health or the environment.
 - Including the volume of water used for fracking within calculation of sustainable limits.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Publicising action protocols and risk reduction plan in the event groundwater contamination is detected.
 - Disclosing the makeup of fracking fluid via a fracking chemical database.
 - Adding nontoxic environmental tracers to fracking fluid help to make cases of potential contamination more evident.
- Companies interested in exploiting shale gas resources may as part of their application:
 - Model the cumulative effects on the groundwater resource prior to fracking.
 - Understand the potential chemical and hydraulic effects of injecting produced water into a saline aquifer.

Well Integrity

Faulty well construction is one of the major conduits for potential groundwater contamination (Watson and Bachu, 2009). The development of horizontal drilling and fracking has made shale gas development possible by increasing the surface area available for gas production. The American Petroleum Institute (API, 2009) states that the goal of well design is to “ensure the environmentally sound, safe production of hydrocarbons by containing them inside the well, protecting ground water resources, isolating the hydrocarbon-producing formations from other formations, and by proper execution of hydraulic fractures and other stimulation operations.”

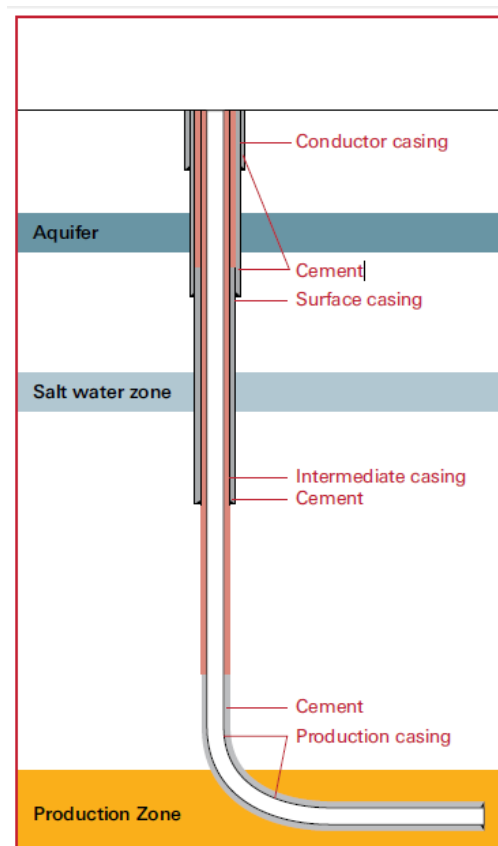


Figure 19: Schematic diagram of the multiple casings used to protect non-target units including potable aquifers from gas shale zones (USDOE, 2009).

Isolation in drilling is provided by how the well is constructed. A well is series of holes of decreasing diameter, lined with steel or other materials to form continuous strings (Figure 19). The parts of the well are:

- Conductor casing: Provides the foundation for the well, set in the ground to ~30 metres, prevents collapse of the well;
- Surface casing: Proceeds from the surface and to below any aquifers. Its primary purpose is to protect groundwater resources. It generally consists of cement;
- Intermediate casing: Isolates the well from non-potable aquifers that may cause instability and abnormal pressure. It generally consists of cement; and
- Production casing: The final well bore is drilled into the target formation. It is lined with production casing to the intermediate casing or above. The fracking process occurs through the production casing (Royal Society and Royal Academy of Engineering, 2012).



Well failure may come from:

- Blowout: sudden escape of gas and fluids from a well;
- Annular leak: poor cementation allowing contamination to move vertically between casings and the casing and the surrounding rock; and
- Radial leak: casing failure allowing fluid to move horizontally out of the well into surrounding units (Royal Society and Royal Academy of Engineering, 2012).

These risks of these failure occurring may be reduced by following industry best practice. The most cited guidelines for shale gas well construction and integrity are from the American Petroleum Institute (http://www.api.org/~media/Files/Policy/Exploration/API_HF1.pdf).

Well completion knowledge is constantly being reviewed and improved on as experience and technology permits. It is important that Australia's well completion guidelines keep pace with ongoing developments.

Decommissioning

Because of the high potential for groundwater contamination from the wells, decommissioned wells need to be effectively sealed for hundreds if not thousands of years. Typically sealing a well is accomplished by filling the well with cement to a predetermined level.

To help give certainty in the future, well operators could submit an abandonment plan to the relevant authorities, with open-ended liability for failures into the future.

Inspection

Checking the quality and fit of drilling casing is vital. This may be carried out through pressure tests (at each phase of drilling), downhole geophysics to test the quality of the casing and testing of cement formulas to ensure that they meet the appropriate standards for the well depth and location (Royal Society and Royal Academy of Engineering, 2012).

The people conducting inspections need to have the necessary qualifications as well as the appropriate levels of impartiality and independence from operators and those with a financial interest in the project (Royal Society and Royal Academy of Engineering, 2012). Ideally, inspections should continue after decommissioning with trigger values developed linked to remedial actions.

The results of any inspection should be communicated to the operators and public as necessary.

Australian experience

The industry body, APPEA and the key states involved in CSG production have developed well construction guidelines for the CSG industry.

- Australian Petroleum Production and Exploration Association (APPEA) (http://www.appea.com.au/images/stories/pdfs_docs_xls/NewsMedia/CSG_Factsheet_Wells.pdf);
- NSW (http://www.nsw.gov.au/sites/default/files/uploads/common/CSG-wellintegrity_SD_v01.pdf); and
- Queensland (http://mines.industry.qld.gov.au/assets/petroleum-pdf/csg_code_of_practice.pdf).



These guideline and examples from around the worldwide could be adopted and modified as needed for the Australian shale gas industry.

Future Considerations

Based on world experience of fracking for shale gas, the following suggestions for lowering risks come from Royal Society and Royal Academy of Engineering, 2012, American Petroleum Institute (http://www.api.org/~media/Files/Policy/Exploration/API_HF1.pdf), APPEA (http://www.appea.com.au/images/stories/pdfs_docs_xls/NewsMedia/CSG_Factsheet_Wells.pdf),

To help lower the risk of well failure and manage the effects of failure:

- Collaboration between the states and Commonwealth is vital to developing a transparent and consistent regulatory framework for shale gas. Components of the framework include:
Components of the framework include:
 - Enforcing best practice drilling, well completion and decommissioning standards need to be mandated to protect and isolate potable aquifers and environmental values.
 - Reviewing and improving well completion guidelines as experience and technology permits.
 - Employing independent inspectors with the requisite qualifications as well as an appropriate level of impartiality and independence from operators and those with a financial interest in the project. Ideally inspections should continue after decommissioning.
 - Developing trigger values indicating problems linked to remedial actions.
 - Well operators submitting an abandonment plan to the relevant authorities, with open-ended liability for failures into the future.
- Make transparent documentation and communication to the public and to regulatory agencies a priority. Communication, transparency and meeting community expectation will help to build community consent to operate. Suggested activities include:
 - Communicating the results of any inspection to the operators and public as necessary.
 - Publicising action protocols and risk reduction plan in the vent of well failure.
 - Reporting any detected well failures and the actions undertaken to remediate problem in a timely and transparent manner.



Risk Analysis and Uncertainty

The following risk assessment looks at the social, financial and environmental risks of possible results related to the geological risks of induced seismicity, water management and well failure.

Issue: Earthquake ($M_L > 0.5$ Trigger Level) due to shale gas operation	Event Likelihood	Consequences	Description of Consequences & likelihood
Assessment	Likely	<u>Social</u> : Medium <u>Financial</u> : Medium <u>Environmental</u> : Small	<u>Social</u> : Fracking opponents and members of affected communities likely to be alarmed at trigger levels being reached. This will likely affect social license to operate. <u>Financial</u> : Shutdown of fracking operation and the subsequent investigation may be expensive. <u>Environmental</u> : None
Reliability if your Assessment	Medium	Medium	Medium
Risk management and mitigation options	The suggestions for induced seismicity (Future Consideration 1) will help to reduce the likelihood of trigger levels being breached in the first place. If trigger levels are reached, communicating the results and reaction in a timely and transparent manor will help to reduce the risk of negative social perceptions.		
Other comments			

Issue: Earthquake ($M_L > 3$, causing damage) due to shale gas operation	Event Likelihood	Consequences	Description of Consequences & likelihood
Assessment	Highly Unlikely	<u>Social</u> : Large <u>Financial</u> : Large <u>Environmental</u> : Small	<u>Social</u> : An earthquake causing damage is highly likely to destroy the social contract to operate. <u>Financial</u> : The operating company is likely to face lawsuits from affected people, as well as having operations shut down for a long period. Further, other shale gas companies throughout Australia



			may face backlash. <u>Environmental</u> : It is unlikely that an earthquake powerful enough to negatively affect the environment will occur.
Reliability if your Assessment	Medium	Medium	Medium
Risk management and mitigation options	The suggestions for induced seismicity will help to reduce the likelihood of a destructive seismic event occurring. In addition, following best practice for well design and fracking will also decrease the potential for a large seismic event occurring. The reaction of affected companies and regulatory agencies to a large seismic event will affect the financial and social consequences of the event. Transparency and timely communication is the key to regaining social consent for shale gas.		
Other comments	The above assumption of the consequences presumes that the seismic event caused by fracking occurs in a populated area. Most shale gas basins are located in remote Australia, which may help to reduce the effects of property damage, but the social contract and the resulting pressure on the oil and gas company are likely to still be strongly affected.		

Issue: Contamination of potable aquifer	Event Likelihood	Consequences	Description of Consequences & likelihood
Assessment	Unlikely	<u>Social</u> : Large <u>Financial</u> : Large <u>Environmental</u> : Large	<u>Social</u> : A contaminated aquifer will support the already negative view of shale gas among opponents. Negative information from shale opponents is likely to become normative with the wider community. <u>Financial</u> : Clean-up costs, fines and the negative effects on future shale gas development high. <u>Environmental</u> : Once contamination occurs, it may be very difficult to remediate an aquifer. Further environmental damage will depend on the depth of the



			aquifer affected (shallow, unconfined aquifers are more likely to directly impact the environment), the area and volume of contamination, and the number of human and environmental users affected.
Reliability if your Assessment	Medium	Medium	Medium
Risk management and mitigation options	The suggestions for protecting groundwater and surface water (Future Consideration 2) will help to reduce the likelihood and consequences of aquifer contamination. Following them may particularly help to reduce the social consequences of aquifer contamination by assuring the public that all potential risk reduction measures were undertaken.		
Other comments	Consequences are based on the aquifer contamination occurring in an area where potable water supply is affected. Contamination occurring in remote areas will also be serious but the consequences for social, financial are likely to be reduced to Medium. Because of the difficulty in remediation, environmental consequences remain Large.		

Issue: Over extraction from aquifer resulting in reduced water availability for the environment or other users/aquifer interference	Event Likelihood	Consequences	Description of Consequences & likelihood
Assessment	Likely	<u>Social</u> : Medium <u>Financial</u> : Low <u>Environmental</u> : Medium	<u>Social</u> : In an over allocated system like the Hunter Valley in NSW, over extraction of water for shale gas will directly affect water availability for other users. Even with make good provisions, community backlash is likely to be high. <u>Financial</u> : The costs associated with over extraction of groundwater are generally relatively low, generally a fine and/or a make good provision. <u>Environmental</u> : Over



			extraction especially in arid areas may take many years to reverse. Lowering of water tables may negatively affect groundwater dependent ecosystems and reduce streamflow.
Reliability if your Assessment	Medium	Medium	Medium
Risk management and mitigation options	The likelihood of over extraction of an aquifer occurring will be reduced if water extraction is included in normal water allocation/licensing processes run by the states and territories. In addition, following the Future Consideration for protection of groundwater and surface water resources (Future Consideration 2) will help companies and government agencies understand and manage risk.		
Other comments	Consequences are based on the over extraction occurring in an area where water supply is affected. Over extraction occurring in remote areas may also be serious but the social consequences reduce to Small.		

Issue: Well failure	Event Likelihood	Consequences	Description of Consequences & likelihood
Assessment	Likely	<u>Social</u> : Medium <u>Financial</u> : Medium <u>Environmental</u> : Medium-Large	<u>Social</u> : Well failure will help to feed negative perceptions of shale gas. <u>Financial</u> : Short term clean-up costs for the company. Medium term costs include fines and loss of revenue. <u>Environmental</u> : Highly saline water including NORM and petrochemicals such as BTEX may be spilled on the surface and potentially enter potable aquifers. The degree of damage will depend on the volume of fluid released. In addition, large volumes of methane and other greenhouse gasses



			may be released into the atmosphere.
Reliability if your Assessment	Medium	Medium	Medium
Risk management and mitigation options	Following suggestions for well integrity (Future Consideration 3) will help to reduce the risk of well failure occurring. Transparency, timely communication of well failure and a concrete and actionable plan for remediation of well, will help to lower the risk associated with negative social perception.		
Other comments	The consequences described are for a single well failure. Multiple failures are likely to have ever greater consequences as it becomes clear the failure is not due to an isolated incident but may be a systematic failure in technique and/or standards.		



Conclusions

Shale gas presents a great opportunity for Australia as it may supply large quantities of cheap, reliable fuel for both domestic and export markets, as well as providing jobs in rural and remote Australia. Importantly, we need to learn from the mistakes of the CSG boom, namely the need to develop the knowledge/regulatory base necessary to manage shale gas exploration and production before widespread exploitation takes off.

Shale gas development will not occur in a vacuum. It will exist alongside CSG, conventional oil and gas, geothermal, mining, agriculture, CCS etc. All of these activities have the potential to perturbate “natural” groundwater flow. When assessing the impacts of any one activity, all other future activities must be included. Shale gas is just one more potential landuse.

The assessment for shale gas risks could be incorporated into the existing Bioregional Assessment Process underway between the states and Commonwealth. Understanding and managing the risks associated with shale gas will help to ensure that Australia can make the best use of its resources.



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