Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory

APPEA Submission

30 April 2017

the voice of australia's oil and gas industry

Contents

1. Introduction

The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body representing the upstream oil and gas exploration and production industry. APPEA has more than 80 full member companies comprising oil and gas explorers and producers in Australia. APPEA members produce an estimated 98 per cent of the nation's petroleum. APPEA also represents more than 250 associate member companies providing goods and services to the upstream oil and gas industry. Further information about APPEA can be found at www.appea.com.au.

APPEA's member companies pursuing the development of onshore gas resources in the Northern Territory are Beach Energy, Central Petroleum, Inpex, Origin Energy, Pangaea Resources, Santos and TriStar Petroleum. The exploration permits held or applied for by these companies are marked in green on the map below. The areas in red designate the exploration permits held or sought by companies who are not APPEA members.

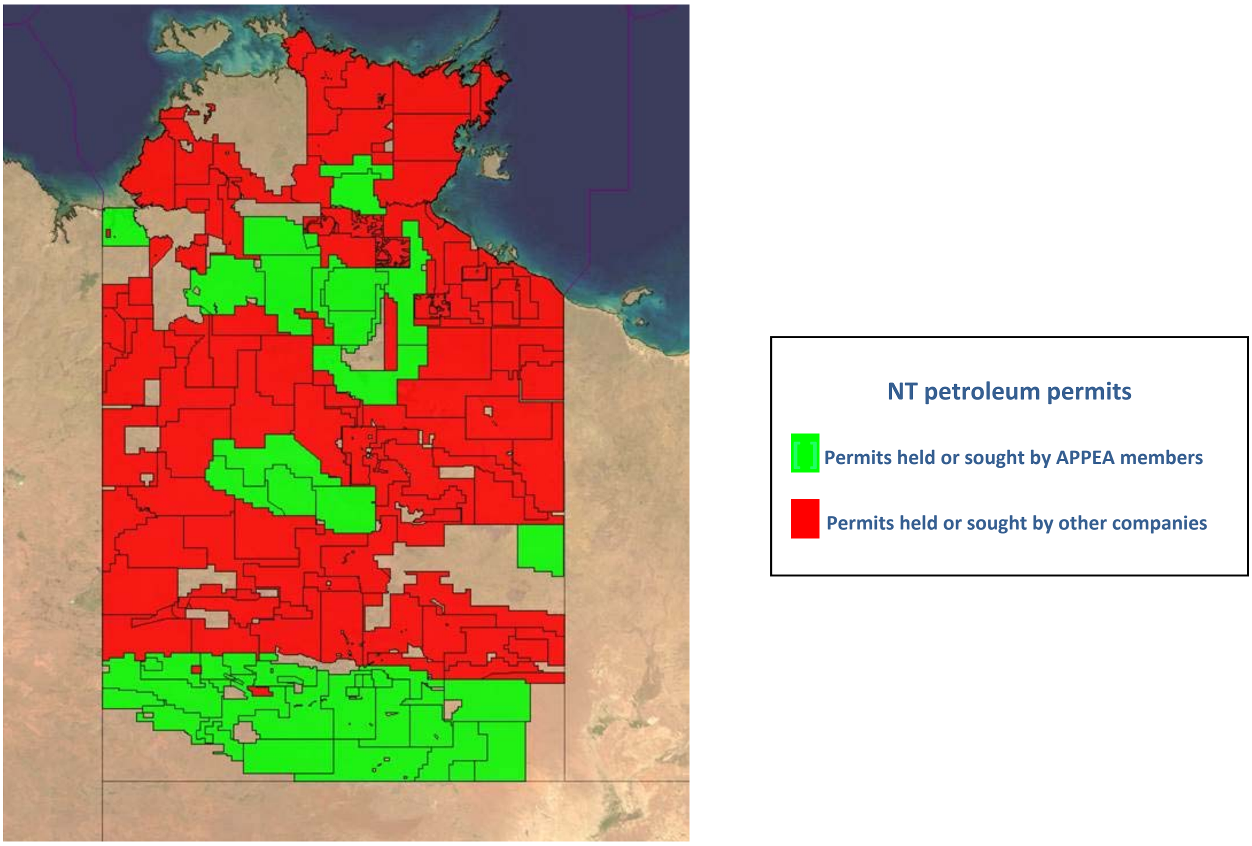


Figure 1 NT petroleum permits

This submission is intended to give the Panel an appreciation of the body of science, research, and regulation that underpins the modern Australian onshore natural gas industry.

To this end we have provided primary references from respected institutions including:

- The CSIRO
- The Australian Government Bureau of Resources and Energy Economics
- The Australian Council of Learned Academies
- The Australian Government's Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development
- The Queensland Valuer-General
- The Queensland GasFields Commission
- The Queensland Department of Health
- The Western Australian Health Department

1.1. Foreword

The Inquiry into Hydraulic Fracturing in the Northern Territory provides a forum for detailed examination and balanced discussion of the opportunities and risks presented by fracking.

Evidence from many similar inquiries, as well as numerous scientific reports and decades of industry operations, shows that the risks are well known and can be managed.

And the opportunities for the Northern Territory are transformational.

In recent years, the Territory has enjoyed the strongest economic growth of any Australian economy, due largely to construction activity associated with INPEX's Ichthys liquefied natural gas project. New projects are now needed to support the NT economy as Ichthys transitions from construction to production.

That new investment is needed to arrest a forecast decline in taxation and royalty revenues.

Sustainable development of the Territory's onshore natural gas resources can deliver the new jobs and investment the Territory needs. In 2015, Deloitte Access Economics research found that developing the Territory's substantial shale gas resources could create up to 6300 new long-term jobs and generate up to $1 billion in additional NT Government revenue over the next 20 years.

By 2040, the NT's Gross State Product could be between $5.1 billion and $7.5 billion higher than the 2012-13 base case in real terms. This represents an increase of between 26 percent and 37 percent on current estimates for the NT economy.

The job growth projected by Deloitte Access Economics would mean the onshore gas industry has the potential to be the second or third largest private sector employer in the NT.

The potential for these substantial and stabilising public benefits of resource development were further evidenced by Origin Energy's recent announcement of major gas resource in the Beetaloo Sub-basin.

Of course, the economic benefits would be diminished if they came with negative environmental impacts – but Territorians can be confident that will not be the case.

The gas industry has a demonstrated track record of safe, sustainable operations in South Australia, Queensland, Western Australia, NSW and Victoria – and here in the NT, where the first well was "fracked" in 1967 – 50 years ago this year.

Around Australia, thousands of wells have been drilled – and more than 1000 have been fracked – with no significant impact on the environment or groundwater resources.

In more than 50 years of onshore gas exploration and production, some minor surface incidents have occurred, but none that have caused the type of environmental harm some people claim is inevitable.

As with any industry, there are risks involved that must be managed and minimised.

Robust regulations must be enforced to ensure the highest standards are maintained. The NT gas industry supports the work now being done to finalise a world-class regulatory framework for the Territory's onshore gas industry.

The industry is also committed to ensuring the equitable treatment of all stakeholders, particularly Traditional Owners, pastoral leaseholders and others on whose land development would take place.

We must maintain respectful partnerships between landholders and our industry. The oil and gas industry, Traditional Owners and pastoralists have been working together in the NT for many years. Around the Territory, over 50 pastoralists have land access agreements in place and are working collaboratively with our industry.

We are proud of our long track record of working with pastoralists and other landholders. Experience shows that when landholders and explorers talk about their plans and activities, identify issues and work together to find solutions, everybody benefits. We will continue to focus on building relationships based on trust and mutual respect.

Too often a false conflict is imagined between economic development and environmental protection. The oil and gas industry is committed to delivering investment, jobs and other public benefits while at all times protecting the environment.

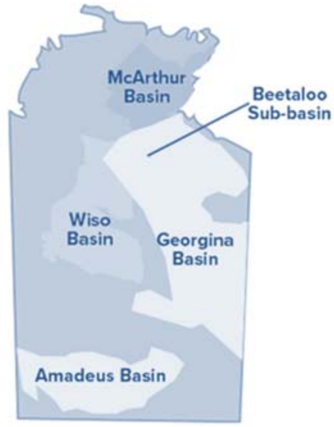
We understand the community has genuine questions and concerns. The industry is committed to responding to these. But all too often such concerns are prompted by false and exaggerated claims peddled by opponents of development, who have often declared they intend to stop all new oil and gas activity.

A balanced discussion is required, grounded in science and reflecting the lived experience of the gas industry.

We trust this inquiry will provide the opportunity for such a discussion, and welcome the efforts the panel has already made to support an informed public debate.

1.2. Why natural gas?

The Northern Territory could generate significant additional economic, environmental and social benefits through greater use of its substantial natural gas resources. A large part of the onshore Northern Territory comprises oil and gas bearing sedimentary basins including the Amadeus, Ngalia, Pedirka, Simpson, Eromanga, Georgina and greater McArthur basins.



Natural gas is an essential input in the manufacturing and mining sectors, as well as a critical direct source of energy for those industries. It is estimated by Deloitte Access Economics[1] that half the gas used in Australia is used by those industries, in turn supporting 949,000 jobs and contributing $194 billion to our economy.

Natural gas is also a key transport fuel, with 380,000 vehicles in Australia running on gas.

Using more natural gas in Australia's power generation and resource processing would significantly enhance our nation's ability to meet increasing energy needs while at the same time reducing greenhouse gas emissions. Natural gas is a flexible fuel, both in technical and economic terms, as it can react quickly to demand peaks, and can support intermittent renewable energy.

The United States electricity sector in the has led the world in cutting CO_2 emissions, largely due to natural gas displacing coal in power generation. A recent report by the US Energy Information Association (EIA) noted that the current shift of electrical generation fuels to natural gas has accounted for 63 percent of the 12 percent total reduction in U.S. energy-related CO_2 emissions during last decade.[2] Natural gas has prevented 1.5 billion metric tons of carbon dioxide from being emitted from power plants in the United States.

These outcomes are possible because available natural gas power generation technologies can slash greenhouse gas emissions by 55 per cent compared to the National Electricity Market (NEM) average, and by 68 per cent compared to current brown coal generation technologies and 61 per cent compared to current black coal generation technologies[3].

This environmental benefit is illustrated in Figure 2 Estimated Operating Emissions for New Power Stations (kg CO2-e/MWh), which shows, using data from page 63 of the Preliminary Report, the significantly lower greenhouse gas emission associated with the use of gas-fired power generation compared to the use of other conventional fuels.

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[1] Deloitte (2016), *Gas Vision 2050 dataset*, work completed for Energy Networks Australia, November 2016.
[2] U.S. Energy-Related Carbon Dioxide Emissions, 2015 https://www.eia.gov/environment/emissions/carbon/
[3] Commonwealth of Australia, (2016), *Preliminary Report of the Independent Review into the Future Security of the National Electricity Market*, , p.63, www.environment.gov.au/system/files/resources/97a4f50c-24ac-4fe5-b3e5-5f93066543a4/files/independent-review-national-elec-market-prelim.pdf

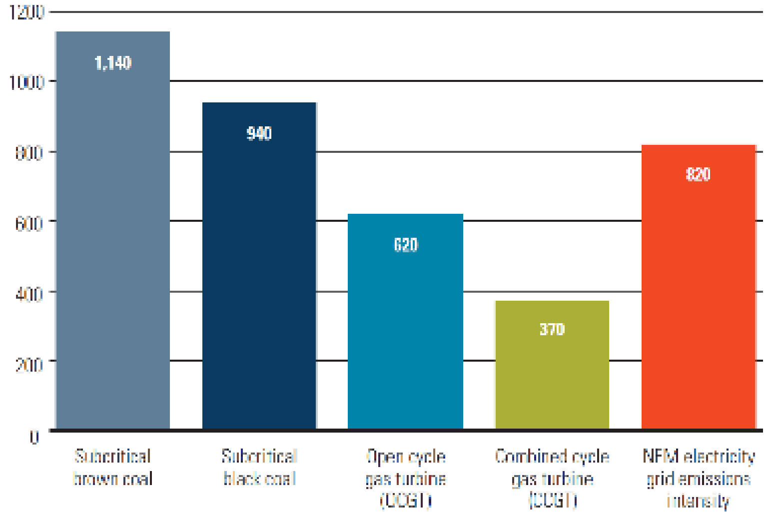

Figure 2 Estimated Operating Emissions for New Power Stations (kg CO2-e/MWh)

Source: Data from the Preliminary Report (2016), page 63.

Similarly, the Australian Council of Learned Academies (ACOLA) in 2013[4] found using gas to provide more baseload and peak electrical power generation in Australia – in scenarios of higher use of both renewables and gas – would deliver substantial emissions reductions. ACOLA found such an outcome would reduce the Australian electricity generation sector's emissions by between 54 Mtpa and 103 Mtpa CO_2-e (million tonnes per annum, carbon dioxide equivalent) by 2030 – a reduction of 27 per cent to 52 per cent from the base case of 197 Mtpa CO_2-e in 2012.

The increased use of natural gas also has several additional environmental benefits, such as:

- Almost no fine particulate emissions in combustion (PM10 and PM2.5)
- Reduced emissions of sulphur dioxide (an important contributor to smog and acid rain) and nitrogen oxides.
- Significantly lower demand for water for power station cooling.

With this in mind, APPEA welcomes the observations made in the Finkel Preliminary Report about the role natural gas can play in the NEM in the future, as we strive to achieve the three goals (the energy trilemma, identified in the Preliminary Report on page 10) of a high level of energy security and reliability, universal access to affordable energy services, and reduced emissions.

In particular, APPEA supports the observations made on page 58 of the Preliminary Report:

> *Gas has the potential to smooth the transition to a lower emissions electricity sector. Gas generation provides the synchronous operation that is key to maintaining technical operability with increased renewable generation until new technologies are available and cost-effective. Furthermore, gas is dispatchable when required.*

A recent paper[5] by Syracuse University and the National Bureau of Economic Research, conducted jointly with researchers from the Fondazione Eni Enrico Mattei and Euro Mediterranean Centre on

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[4] Cook, P, Beck, V, Brereton, D, Clark, R, Fisher, B, Kentish, S, Toomey, J and Williams, J (2013). *Engineering Energy: Unconventional Gas Production*. Australian Council of Learned Academies (ACOLA), www.acola.org.au.

[5] Verdolini E, Vona, F and Pope, D (2016), *Bridging the gap: do fast reacting fossil technologies facilitate renewable energy diffusion?* www.feem.it/userfiles/attach/20167271022524NDL2016-051.pdf.

Climate Change in Italy and French Economic Observatory Sciences Po and SKEMA Business School in France, discusses the role of fast-reacting fossil technologies, which includes most gas generation technologies, in supporting renewable energy investments.

It does so by studying the deployment of these two technologies in 26 OECD countries, including Australia, between 1990 and 2013. The paper finds that a 1 per cent increase in the share of technologies such as gas fired generation capacity is associated with a 0.88 per cent increase in renewables in the long-run.

The paper makes a number of very important conclusions, three of which stand out as directly relevant to the energy debate underway in Australia and issues that are being considered by the Independent Review.

Firstly, it shows that countries where gas-fired generation capacity is available are more likely to invest in renewable energy generation particularly over the longer-term.

Secondly, gas-fired generation, due to its quick ramp-up times and lower capital costs compared to traditional baseload technologies, has enabled renewable investments by providing reliable back-up capacity to support variable renewable supply.

And lastly, renewables and fast-reacting gas-fired power general technologies appear as highly complementary and should be jointly installed to meet the goals of reduced emissions and stable supply.

This mean that as the penetration of renewable energy increases, so will the requirements for increased back-up capacity. Serious stresses will be put on energy systems, such as the NEM, unless the relationship and the complementarity between gas-fired power generation and renewable energy technologies are appropriately acknowledged.

The paper goes on to argue that a debate that sets up renewables and gas as being in opposition misses this important point.

However, current policy arrangements in many jurisdictions are actively working against gas being able to play a more prominent role in addressing the energy trilemma (cost, reliability and sustainabiltiy) as identified in the Finkel Preliminary Report.

1.3. Demand for natural gas remains strong

The IEA forecasts gas to be the fastest-growing fossil fuel in the world, increasing by nearly 50 per cent to account for 24 per cent of total energy by 2040. The strongest growth in natural gas consumption is projected for the countries of non-OECD Asia, where economic growth leads to increased demand. Natural gas consumption in the non-OECD region grows by an average of 2.5%/year from 2012 to 2040.

Natural gas is an essential commodity for modern Australia. Natural gas is needed for power generation and is an indispensable feedstock for manufactured products such as fertilisers, plastics and chemicals. The Australian Energy Market Operator (a body established by COAG) forecasts that residential, commercial, industrial demand for gas in Eastern Australia will remain strong over the next 20 years and total gas demand will rise significantly as Australian exports of gas ramp up.

In the five years 2016-21, the total annual gas consumption in Australia is forecast to rise rapidly as Queensland's liquefied natural gas (LNG) export facilities ramp up production.

Annual gas consumption is then projected to remain relatively steady over the rest of the 20-year outlook period to 2035. The Northern Territory uses approximately 46 petajoules of natural gas per year. Primarily this is for Electricity supply (26.2 PJ), and mining (19.7 PJ)[6]

Gas demand in eastern Australia will continue to be strong and will increasingly need to be supplied from unconventional sources such as coal seam and shale gas.

Australia has abundant gas resources to meet domestic and export requirements, however the traditional supplies of natural gas from Bass Strait and the Cooper Basin are in decline and Australia needs to take steps now to unlock new reserves.

1.4. Conventional vs Unconventional Gas

The distinction between "unconventional" gas and "conventional" gas is simply based on the type of rock the gas is found in. Both "conventional" and "unconventional" natural gas is methane. CSG and Shale is almost pure methane whereas conventional gas may also contain ethane, propane, butane, and other hydrocarbons.

Natural gas is formed from the decomposition and pressurisation of algae, plankton and other organisms that were deposited many millions of years ago in swamps, lakes, river deltas, and seabeds. This gas is held in rocks far below the Earth's surface. A gas reservoir is a subsurface pool of gas contained in a geological formation.

Natural gas (or methane) is found in several different types of rocks, including shales and coal seams, as well as conventional sandstone reservoirs. Conventional gas reservoirs largely consist of porous sandstone formations capped by impermeable rock, with the gas stored at high pressure. Australia's conventional gas reserves are mostly offshore. Conventional gas generally flows to the production well and to the surface under pressure, though some wells need compression to flow. This type of production has historically been the source of most natural gas, hence the term "conventional".

[6] Commonwealth of Australia, (2017), *Australian Energy Statistics 2017*. https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx

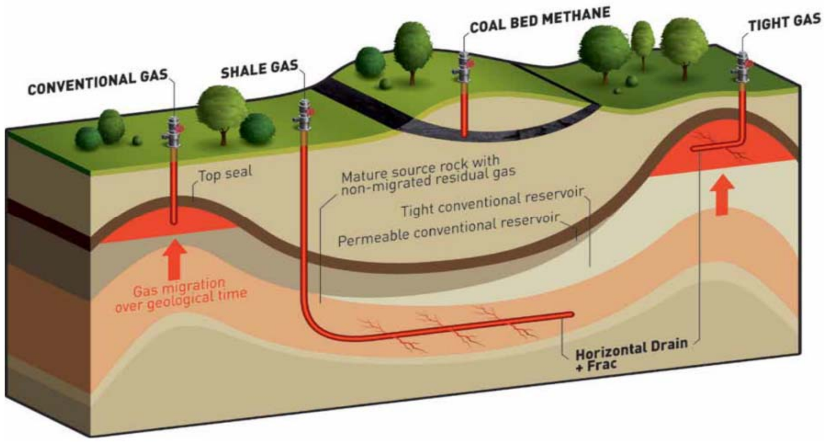


Image 1 Types of Gas reservoirs

Unconventional gas reservoirs include coal seams, shale, and tight sandstone formations (where the sand is more compacted). Coal seam gas (CSG) is found in coal seams where methane is bonded to the coal and is trapped underground by water pressure. To extract CSG, water already in the coal seam, known as formation water, needs to be pumped out to lower the reservoir pressure and release the gas. Shale gas and tight gas occur within rock formations that have extremely low permeability making it difficult for gas to flow to wells (refer to Figure 3 Porosity of Rock)

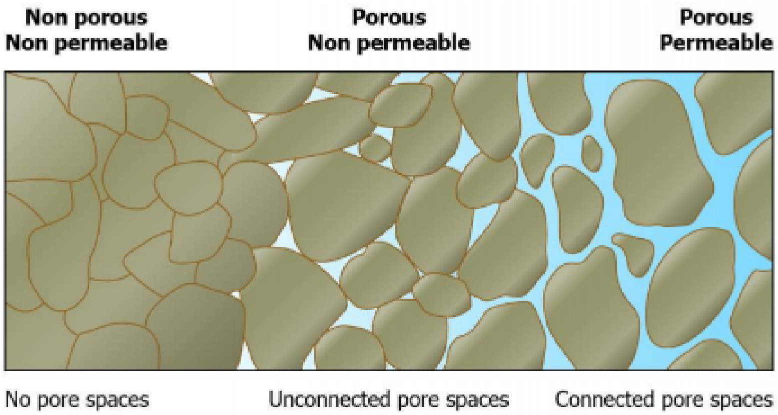


Figure 3 Porosity of Rock

Onshore conventional gas has been produced in South Australia, Queensland, New South Wales and Victoria for many years. The Cooper Basin has been developed as a conventional onshore field. Hydraulic fracturing *may* be used in CSG and conventional gas production (to date only about 10% of wells in Queensland have required hydraulic fracturing) (Queensland Government[7]). Hydraulic fracturing is always used in shale gas and tight gas wells to increase the flow of gas from the reservoir.

Underground Coal Gasification (or UCG) has been raised at the inquiry and at community sessions. UCG is an entirely different process to natural gas extraction. UCG does not produce natural gas

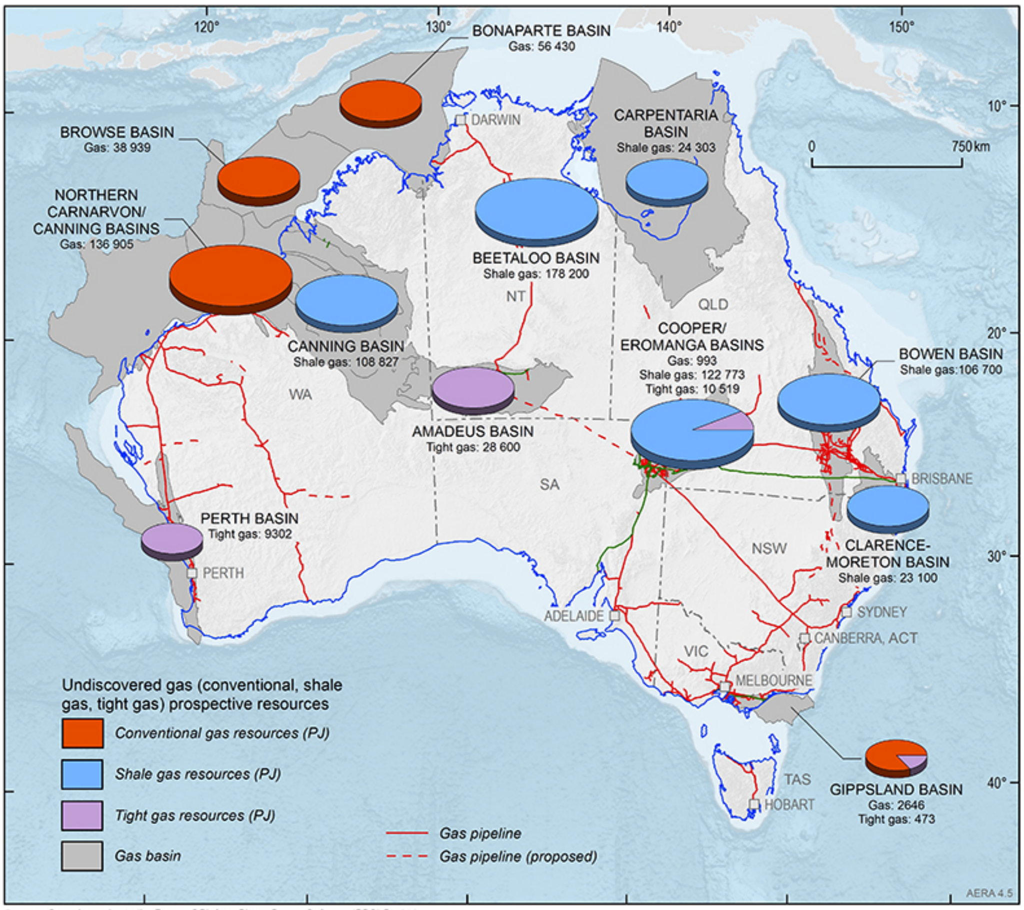
[7] See: www.ehp.qld.gov.au/management/non-mining/fraccing.html

and involves partially burning coal seams in situ and then extracting the resultant mixture of carbon monoxide and hydrogen. APPEA does not represent any companies involved in UCG production.

2. What is Shale Gas?

Shale gas is a natural gas (predominantly methane) found in shale rock.

Shale is a fine-grained sedimentary rock composed of mud that is a mix of clay and other minerals. Shale has a very small particle size, so the pore spaces between the particles are very small. They are so small that oil, natural gas, and water has difficulty moving through the rock. Although the interstitial spaces in a shale are very small, they take up a significant volume of the rock. This allows the shale to hold significant amounts of gas, oil or water but not be able to effectively transmit them because of the low permeability. The oil and gas industry overcomes these limitations of shale by using horizontal drilling and hydraulic fracturing to create artificial porosity and permeability within the rock.



Source: Geoscience Australia, Encom GPinfo, a Pitney Bowes Software (PBS) Pty Ltd.
Whilst all care is taken in the compilation of the field outlines by PBS, no warranty is provided re the accuracy or completeness of the information, and it is the responsibility of the Customer to ensure, by independent means, that those parts of the information used by it are correct before any reliance is placed on them. Accurate at July 2015.

Image 2 Basins with tight gas and shale gas resource potential and gas infrastructure (Source: Geoscience Australia)

According to the NT Geological Survey, the 'best estimate' of NT shale and tight gas resources is approximately 234 Tcf (of this estimate, 119 Tcf relates to basins lying solely within NT boundaries, with the remainder consisting of shared resources with other States). This makes the NT a potentially important player in Australia's gas supply.

The location of the Northern Territory's known and potential shale gas resources in shown in Image 3 Shale gas resources in the NT.

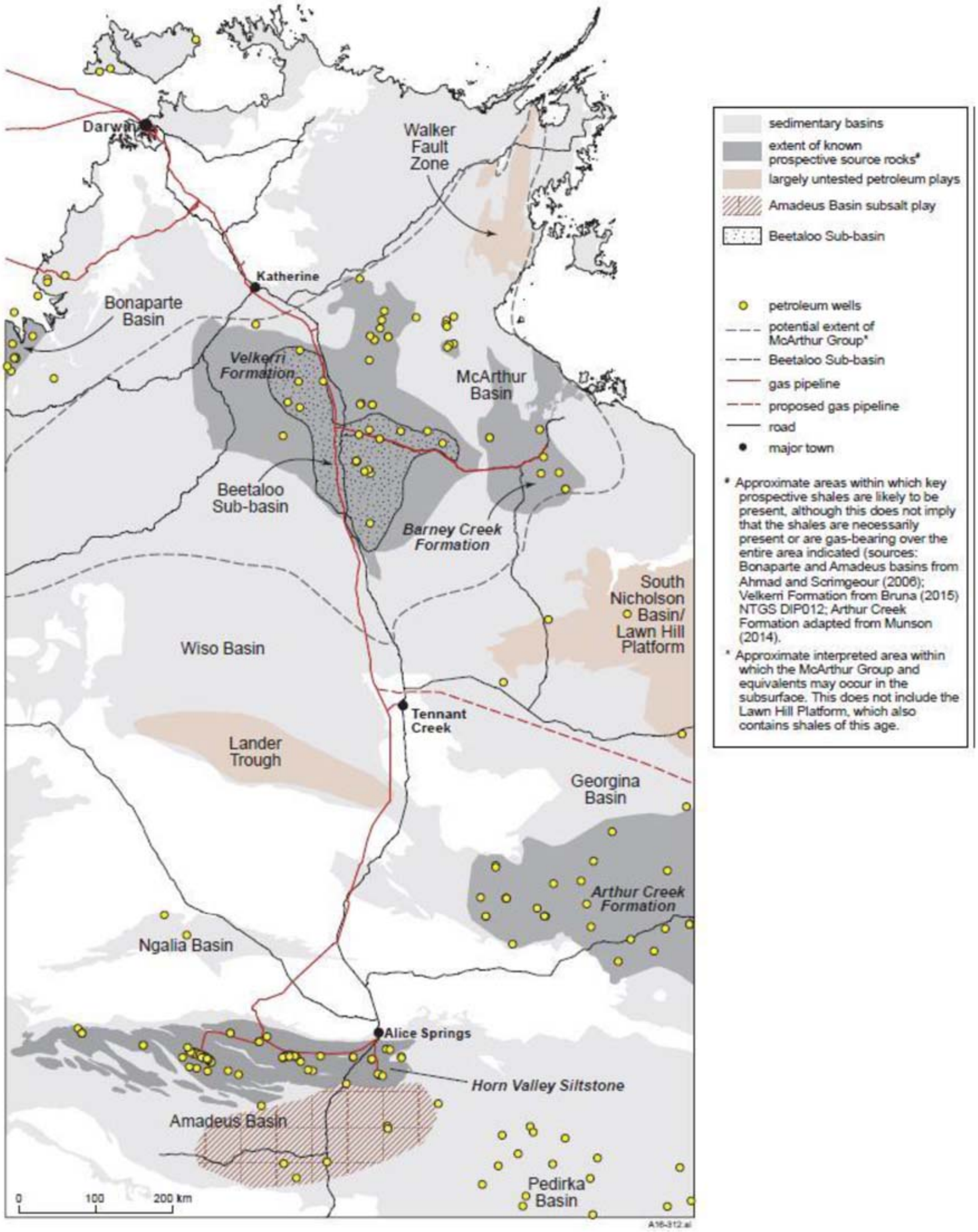


Image 3 Shale gas resources in the NT

The presence of gas in the organic-rich shale sedimentary rocks has been confirmed in the Amungee well drilled and tested by Origin in the Beetaloo Basin. An organic rich shale contains significant amounts (>3%) of organic carbon. A black color in sedimentary rocks almost always indicates the presence of organic materials.

Image 4 Marcellus organic rich shale outcrop (Finck quarry near Elimsport, Pensylvania State, USA) (photo by I. Dyrka)

Shale gas is usually held at depths of more than 2,000 metres – well below the reservoirs used for agriculture and town water supplies. The image below shows the Amungee NW-1H well drilled by Origin Energy in the Beetaloo Basin. It shows the depth of the target resource (>2,400m) compared to the deepest aquifer depths (~100m).

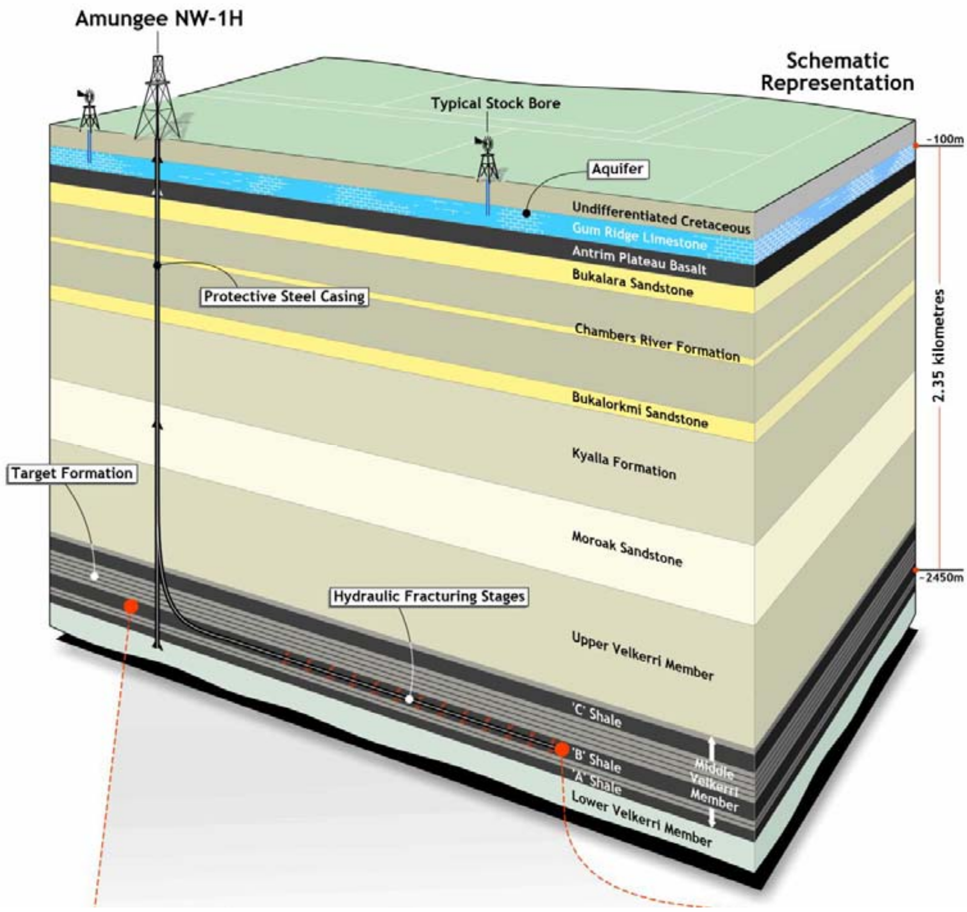


Image 5 Amungee 1 in the Beetaloo Basin (Source: Origin Energy)

To extract shale gas, wells are drilled through upper layers of rock to access the shale. These wells are lined with cemented steel casings to protect groundwater from contamination. To maximise shale gas recovery and minimise surface impacts a technique called horizontal drilling is used. This technique involves the well changing from a vertical to a horizontal direction deep underground. Further information on hydraulic fracturing and well design and integrity are outlined in section 2.

3. Well drilling and well integrity

An oil or gas well is a technically advanced bore hole that reaches hundreds to thousands of metres beneath the earth's surface to tap petroleum resources. In Australia, wells are typically 2,000 to 4,000 metres deep, although some may be as shallow as 300 metres. For the industry these are not challenging depths, as overseas wells beyond 10,000 metres are becoming more common. Water wells for agriculture or domestic use are usually less than 100 metres deep.

Controlling the gases and liquids as they are brought to the surface relies upon long-term well integrity. Not only does the well have to contain the petroleum products inside the well, it must also ensure that subsurface rock layers and any related aquifers penetrated by the well remain isolated from each other. Achieving all this requires high standards of well design and construction.

Structural elements termed well barriers are essential in both the design and construction of wells. There are numerous types of barriers, including well casing, drilling muds, and blowout preventers. These barriers function as containment envelopes to prevent unintentional fluid flow between the geology and / or the atmosphere. The barriers have built-in redundancies to reduce the risks that gases or liquids can escape from a well anywhere along its length, enter a well from untargeted zones, or migrate from one geological zone to another.

Development of unconventional oil and gas resources using modern well cementing and completion techniques leads to excellent wellbore integrity. Technological advances are continually improving well integrity and leak detection.

The most common well integrity risk is slow leakage of methane around the external casing, but the consequences of such leaks, although negative from a climate change perspective, do not threaten health because natural gas is not toxic, the frequency of substantial leaks is low, and the leakage rates are low as well. When leakage is identified, the problem can be quickly remedied. These leaks are referred to as 'fugitive emissions' and are covered in the Air Quality section of this report.

3.1. Well Design

Before a well is drilled, it is carefully designed to make sure it meets the highest safety standards and can withstand challenges such as pressure, corrosion, high temperatures, and fluid flows that may erode pipes. The design also accounts for maintenance programs over the life of the well, which is usually decades-long. Several international standards guide good oil field practice in well construction. [8]

[8] http://www.ogp.org.uk/pubs/485.pdf

3.2. Drilling

A specialist drilling rig is moved onto the drilling lease and drilling commences when the drill bit penetrates the ground (industry refers to this as the well being 'spudded') and will continue until the target depth has been reached.

Drilling an oil or gas well can take a few days or many weeks depending on many factors, including geology, depth of the well, and any issues which are encountered during the drilling operations, and whether the well is vertical, deviated or horizontal.

Image 6 Natural Gas Well Drill Bit (USGS)

3.2.1. Horizontal Drilling

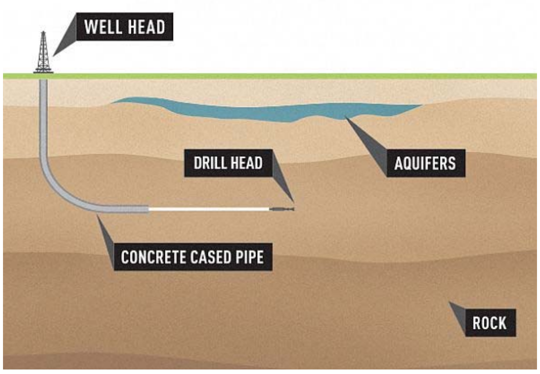
Horizontal (or directional) drilling is a technique used to develop larger oil and gas resources from a single well. Horizontal drilling and horizontal wells have been common practice in the oil and natural gas industries since the 1970s, but the US Department of Energy notes the concept was first introduced as early as 1929.

Direction drilling involves rotating the drill bit in the well bore so that the well targets a length of the reservoir. In Australia, horizontal or "directional" drilling has been common since the 1990s and has been used more recently to target deep shale gas resources in South Australia and NT.

Australia's first horizontal shale gas well was drilled by Santos in SA's Cooper Basin in 2013 and the most recent example was Origin's Amungee NW-1H well in the Beetaloo Basin in the NT.

The Amungee well was drilled in 2015 and hydraulically fractured in 2016. It resulted in an important natural shale gas discovery for the Northern Territory.

These and other horizontal wells have been drilled safely with no impact on water resources or the environment.



Larger wells do of course use more water, sand and other additives, but the technology means fewer wells are drilled overall and the environmental impact is thus reduced.

Today, companies can drill multiple horizontal well paths from a single surface location. Clustering wells onto a single surface location dramatically reduces the overall amount of surface land required for wells and related infrastructure.

Reducing oil and gas wells' surface impacts while also improving production is an important advantage of horizontal drilling. Also called deviated drilling, directional drilling involves deliberately shifting a well's path from the vertical. Wells can be deviated until they are running horizontally. They can even be steered – in real time – upwards or downwards once the horizontal direction is established.

Reasons for directional drilling include:

- Avoiding a surface site that is operationally difficult or environmentally sensitive
- Targeting a larger gas resource from a single well
- Reducing costs or surface impact by drilling several wells in different directions from the one surface location
- Targeting an offshore resource from an onshore site
- Enhancing oil and gas production by drilling in a way that exposes more of the reservoir to the wellbore.

To steer the well path, rotary steerable equipment is mounted on the drill pipe just behind the drill bit. These systems are controlled from the surface to redirect the drill bit to steer the well on any desired path. This technology developed for the oil and gas industry is now also being used in other industry applications, including:

- tunnelling
- construction and civil engineering
- drilling water wells
- laying water pipelines and telecommunication cables.

3.2.2. Multiple wells and batch drilling.

Multiple wells and batch drilling have been used by the oil and gas industry for decades and are well understood.

For multi-well drilling, individual wells are drilled ~5m – 10m from each other. How close the wells can be drilled is generally limited by the room available for the rig. New 'sliding' rigs can cluster the wells very close together and increase the precision and time taken to move the wells.

In Queensland, multi-well pad drilling would be around 8 wells per pad. In some geological setting (such as tight gas in Canada) around 24 wells are drilled from a single pad with two rows of well slots (called a slot map). As a result of the high well slot density, gyroscopic survey systems are run during kickoff operations in most wells due to magnetic interference.

Drilling multiple wells from one pad has a number of advantages:

- 15-20% cheaper than a single well. Less rig moves, less groundworks.
- ~55% lease size reduction per well. Placing several wells on one site reduces the surface impact on the landscape.

- This process further reduces surface disturbance by eliminating the need for additional lease roads. This, in turn, decreases the company's road construction costs.
- Multi-well pads are far more efficient, because once a well is drilled, the rig moves only 20 feet or so to drill the next one. This also reduces vehicle traffic.
- More flexible on well location. This gives landowners more input on both the placement of the wells and the construction of the road leading to those wells

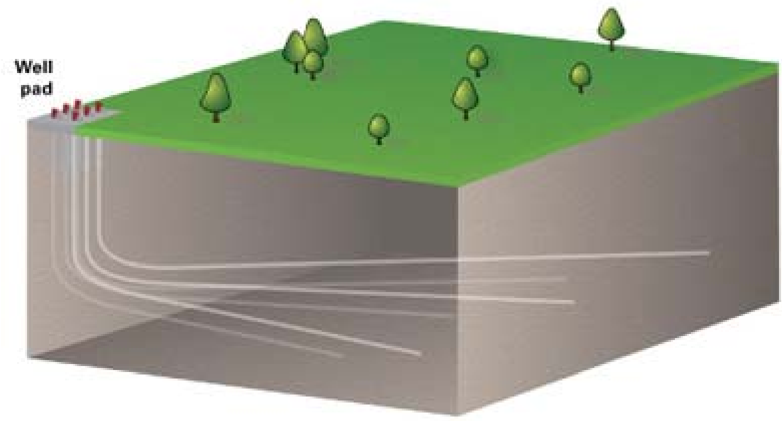
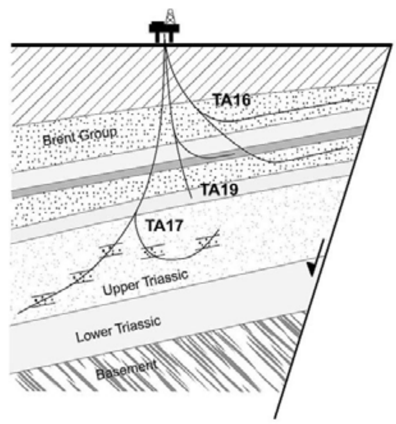


Image 7 Multiple well pad drilling.

3.3. Deviated (lateral) well drilling

In multi-lateral wells, branches run off the sides of the main horizontal bore to expose more of the seam and produce more gas. Each branch can access a separate part of the reservoir and produce into a common single wellbore. The advantage of multilateral wells is that they can be cheaper than if separate wells had been drilled.

The multi-lateral design allows greater exposure of the seam while minimising surface impact. Multiple wells can be grouped on single pad, further reducing the surface footprint. Multi-lateral wells have been used by the oil and gas industry for decades.



Multilateral Wells

3.3.1. Casing

The well is lined with multiple layers of pipe (also called 'casing').

Image 8 Well Casing

Using several casing strings helps back up the integrity of the well if one of the pipes fails. Cement is pumped into the casing between the well and the rock, and between the various strings of casing. This isolates rock or aquifer zones, and prevents unwanted flow between rock zones or inside the well itself. This use of multiple casing strings and cement is the first line of defence for well integrity. There are usually three strings:

- Conductor casing – to secure the near surface section – soil and gravel etc -8 $^{5}/_{8}$" diameter
- Intermediate casing – from surface down to the base of weathered or weak strata – 6 $^{5}/_{8}$" diameter
- Production casing – down to the top of the target formation – 4 ½" diameter

All strings are cemented in place to isolate any aquifers.

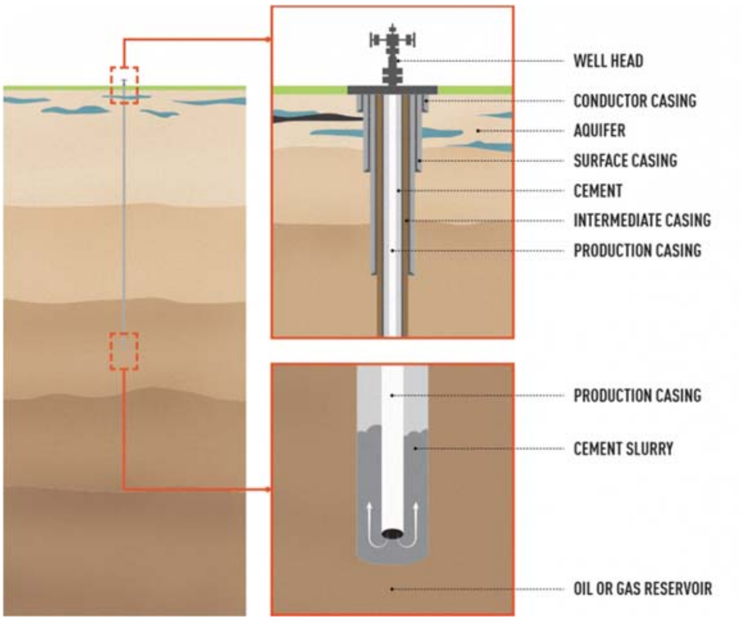


Image 9 Well Casing and Cementing

3.4. Well Cementing

Cement is a critical component of well construction and cementing is a fully designed and engineered process. Cement is used in casing at the time of well construction, as well as in plugging at the time of well abandonment, and less commonly to address production or perforation issues.

It is important to note that the cement used in well construction is a highly engineered, specialised product. It is not the same as the cement use in traditional construction activities such as building and civil works. Well cementing practice and design has decades of research to underpin it. Special formulations and additives are available to customise cement to individual well conditions, including increased resistance to gas migration, naturally occurring chemical ions, low pH environments, carbon dioxide (CO2), high temperatures, sulphate, and mineral acids (King, 2012). Designs may call for using different cements for casing than for plugging a well.

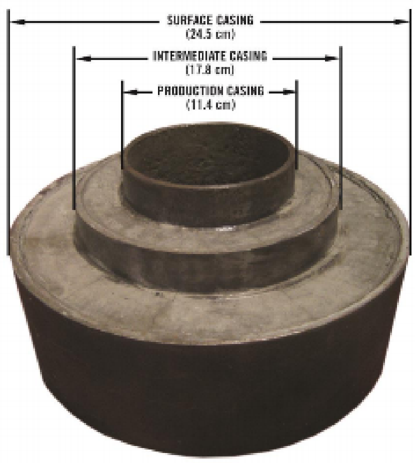


Image 10 Multiple Pipe Casings and Cementation:

3.4.1. Well Perforation

When wells are drilled, the well is cemented with thick steel pipes into the ground to case the well and isolate the various rock strata. This cement isolates aquifers from hydrocarbon zones, stabilises the well, and allows drilling deeper than is possible with uncased wells. However, casing the well also seals off the gas-bearing zone. Drillers must put holes through the casing (and the cement behind it) in order to open the reservoir back up to the wellbore. There are a number of ways to do this, but the most common is using small shaped-charge explosives and a cone of a pyrophoric and relatively soft metal such as zinc or copper.

The small holes cut by the charge allow oil or gas to flow from the reservoir into the wellbore.

Image 11 - example of a perforation charge into sandstone

3.5. What is well integrity?

Well integrity refers to the ability of a well to effectively produce hydrocarbons while protecting the unintended escape of fluids. Well barriers are used to prevent leakages and reduce any risk associated with drilling, production and intervention activities. Some barriers are used temporarily to facilitate various well construction processes. Other barriers are installed permanently to be used during the full service life of the well.

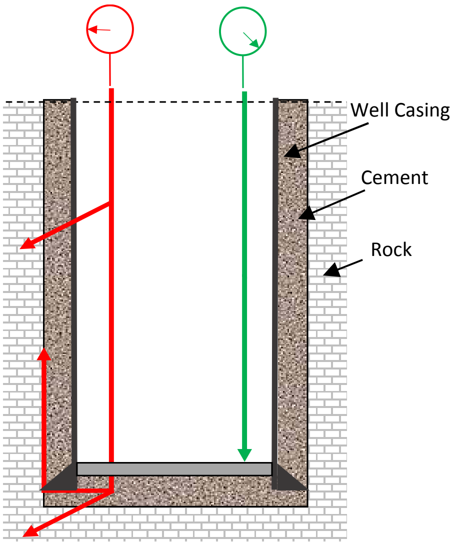
The industry uses three levels of construction and testing to ensure that wells meet required standards:

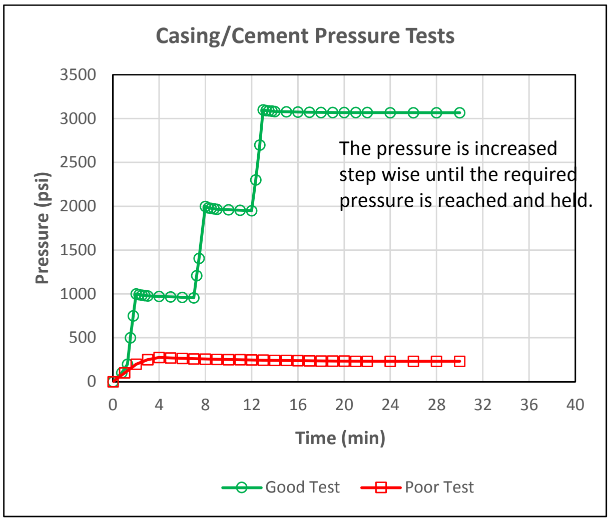
- multiple pipe casings;
- pressure testing; and
- cement bond logs.

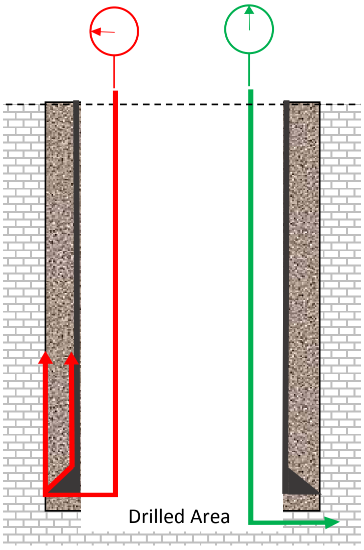
3.6. Pressure testing

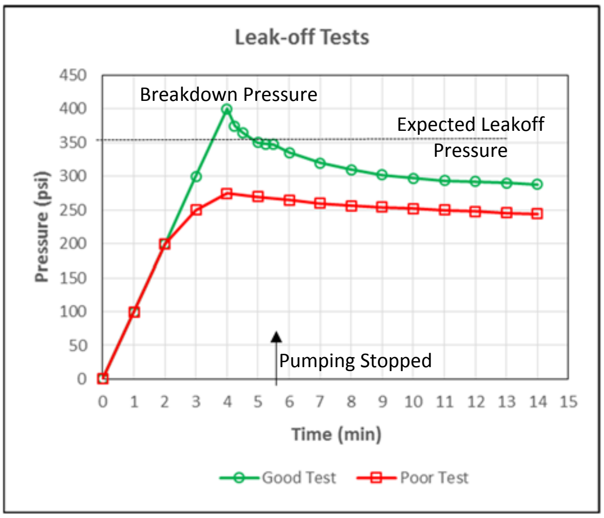
Once a casing has been put in place and cemented, it is pressure-tested to confirm its integrity, or ability to hold pressure. This test is done in steps up to 80 per cent of the maximum pressure rating of the casing to confirm the cement and casing integrity (Figure 2). If further drilling is desired, then the first few metres of rock below the bottom of the casing are drilled and another pressure test is performed. This pressure test is used to confirm that the cement behind the casing can hold pressure up to the point where the rock itself will break down and the pressure leaks off (Figure 3). In other words, a 'good test' signifies that the cement between the rock and the casing can hold pressures higher than the rock itself.

Examples of **'good'** and **'poor'** well pressure tests to confirm well casing integrity: (Postler, 1997)[9]









3.7. Cement bond logs

The third level of well integrity involves measuring the consistency and quality of the cement between the cement, pipe and surrounding rocks. Electronic measuring tools are lowered into the well to measure or 'log' the cement along the depth of the well. Sound waves are used to look at how well the casing is held or bonded to the cement.

The sound waveforms on the log are evaluated for how well the sound waves travel from a transmitter through the pipe, cement and rocks before returning to receivers along the tool.[10] If

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9 Postler, D.P.: *Pressure Integrity Test Interpretation*, paper, SPE-37589-MS, presented at the SPE/IADC Drilling Conference, 1997.

10 Sutton, T., 2009, *Well integrity — Vertical and horizontal cement evaluation*: presentation made at the Stray Gas Workshop, Pittsburgh, Pennsylvania, November 4-6, 2009, http://pa.water.usgs.gov/projects/energy/stray_gas/presentations/3_920_Sutton.pdf

cement bonding is good, sound will not easily transmit through the pipe. Conversely, if cement bonding is poor, the pipe is free to vibrate, allowing for easy transmission of sound.

Cement bond logs are not run in every well, but are a very useful back-up if a pressure test indicates a concern with cement placement, or there are particularly sensitive sections of rock that must be isolated. If a cement bond log shows a large section of poor bonding or quality across an important area, the operator may perform a well maintenance operation with a rig (called a 'workover') to inject cement (called a 'squeeze job') into the problem area.

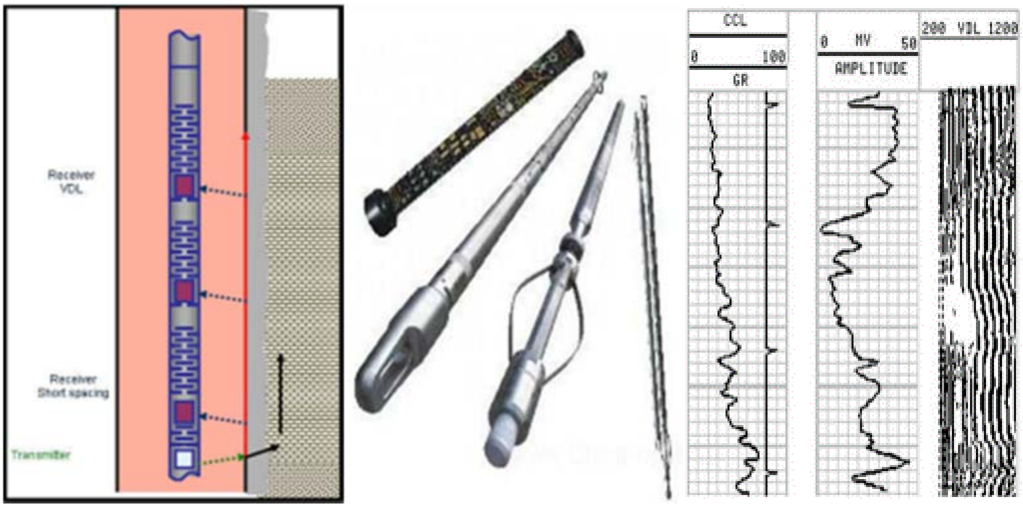


Image 12 Cement Bond Logging equipment and survey data:

3.8. A well's life

Production phase

Once the well has been properly constructed, and its integrity verified, it is then brought into production. A well's productive life is often measured in decades. The world's oldest continuously producing oil well – McClintock Well No. 1 in Pennsylvania[11] – has been producing for over 150 years.

Well maintenance

Each producing well has a maintenance program used to monitor its integrity and schedule regular servicing. Major maintenance programs can occur every few years when a workover rig is brought in to service the well. A measurement of pressure build-up in a casing string (called "sustained casing pressure"), for example, would indicate that a well needs attention. The workover may involve replacing internal piping, testing pressure seals and measuring or logging well parameters such as flow rates and temperatures in the well, fluid sampling and pipe integrity. These measurements can indicate if further tests or repairs are needed, and are a normal part of the well maintenance program that continues for the producing life of the well.

[11] Hill, M. (2011), *150 years later, oil well still producing*, Titusville Herald, published 16 August 2011, www.titusvilleherald.com/articles/2011/08/16/news/doc4e4b452d3c518727905287.txt

End of well life remediation

Once a well has reached the end of its useful life, it must be decommissioned and remediated (the common industry term is 'plugged and abandoned'). Steps taken to remediate a well are usually well defined by the relevant regulator. A typical well remediation uses a drilling rig to remove any equipment in the wells, such as subsurface pumps and pipe tubing. The rig then pumps cement into the well and sets mechanical plugs as a back-up, to create long-term barriers to fluid flow and isolate rock zones.

Once this is done, the well-head is removed, and in onshore wells it is cut off below ground level so that past practices such as agriculture can resume over the well site.

A properly remediated well is very different to a producing well that needs regular measurement and monitoring. A remediated well is designed to be safe and pose no material threat to safety and the environment for future generations.

3.9. Well Abandonment

The industry restores the natural integrity of the formation penetrated by the wellbore. This isolates permeable and hydrocarbon bearing formations are isolated to protect underground resources, prevent potential contamination of potable water sources and preclude surface leakage.

Cement is the most common plugging material used to seal the abandoned wells. Drilling mud, bentonite and mechanical plugs also are used frequently in conjunction with cement.

- **Cement.** Various additives are blended into the cement for specific purposes. Each cementing company uses additives and blends cement based on the customer's specific cementing plan. For instance a retarder or accelerator might be added to slow down or speed up the setting time to allow for longer or shorter pump times and/or the removal of the tubing used to place the cement.
- **Bentonite.** Bentonite, which is a natural material rich in swelling clays, is used commonly to form the base of most drilling muds. Bentonite is placed as a compressed solid and then hydrated to form a dense and low permeability solid mass in the wellbore. Once bentonite is hydrated it creates a potentially more reliable plug that is flexible and self-healing.[12]
- **Mechanical Plugs.** Mechanical plugs are used in some wells to reduce the amount of cement required to plug a well or to provide additional protection from formation pressure in the well.

3.10. Long-term integrity

This claim 'cement can't last forever' is often made by industry opponents to suggest that over time all plugged and abandoned gas wells will leak.

[12] See: www.uq.edu.au/news/article/2017/02/plugging-gap-oil-and-gas

But modeling and analysis into well corrosion show that a properly designed and implemented well can last indefinitely. Yamaguchi, Shimoda, Kato, Stenhouse, Zhou, Papafotiou, Yamashita, Miyashiro & Saito (2013) have investigated the long-term corrosion behaviour of cement in abandoned wells under CO_2 geological storage conditions by simulating the geochemical reactions between the cement seals over a simulated period of 1,000 years. While alteration of the cement seals was found after a period of time, the alteration length after 1,000 years was approximately one meter, leading to the conclusion that cement will isolate CO_2 and upper aquifers over the long-term.[13]

Cement plug integrity in CO2 subsurface storage was also assessed by Van der Kuip, Benefictus, Wildgust & Aiken (2011)[14]. Using estimates for degradation after 10,000 years they likewise came to similar conclusions stating that "*mechanical integrity of cement plugs and the quality of its placement probably is of more significance than chemical degradation of properly placed abandonment plugs*" (literature on corrosion and cement degradation considers CO2 stored at high pressure to be more aggressive than methane).

Rome's Pantheon – built c. 126 AD – has a concrete dome. Almost 2000 years after it was built, the Pantheon still has the world's largest unreinforced concrete dome.

4. More about well integrity

4.1. What is a well failure?

As described above there are multiple barriers in place to protect wells. The terms "well failure" and "well integrity" have sometimes been misunderstood. In the past this misunderstanding has been used to confuse the facts on well integrity. For instance, a 2011 Cornell university study quotes rates of 'barrier failure' (or Sustained Casing Pressure) and gives an impression that an environmental impact follows. This is not true. A single barrier failure with no leak path does not result in well integrity failure. Unless all barriers fail, a leak will not happen.

A failure of a well barrier element will usually result in a well with reduced integrity. A reduction in well integrity does not necessarily mean any environmental impact. If a barrier has failed, there are actions that can be done to restore the failed well barrier (such as re-working the well). Alternatively, the well can be plugged and made secure or in some cases, the well barrier can be redefined and production continued until the failure can be corrected.

[13] Kohei Yamaguchi, Satoko Shimoda, Hiroyasu Kato, Michael J. Stenhouse, Wei Zhou, Alexandros Papafotiou, Yuji Yamashita, Kazutoshi Miyashiro, Shigeru Saito, *The Long-term Corrosion Behavior of Abandoned Wells Under CO2 Geological Storage Conditions: (3) Assessment of Long-term (1,000-year) Performance of Abandoned Wells for Geological CO2 Storage*, Energy Procedia, Volume 37, 2013, Pages 5804-5815, ISSN 1876-6102, www.sciencedirect.com/science/article/pii/S1876610213007467.

[14] M.D.C. van der Kuip, T. Benedictus, N. Wildgust, T. Aiken, *High-level integrity assessment of abandoned wells*, Energy Procedia, Volume 4, 2011, Pages 5320-5326, www.sciencedirect.com/science/article/pii/S1876610211007922.

Failure of all barriers is called a 'loss of well integrity'. The obvious consequences of a loss of well integrity is blowouts or leaks that can cause material damage, personnel injuries, loss of production and environmental damage. How often does well integrity failure happen?

A single barrier loss is more common than a complete barrier loss. The United States has the world's longest history of oil and gas production, and the most intensive drilling programs. The Ground Water Protection Council in the US examined more than 34,000 wells drilled and completed in the state of Ohio between 1983 and 2007, and more than 187,000 wells drilled and completed in Texas between 1993 and 2008. Included in the study period were more than 16,000 horizontal shale gas wells, with multi-staged hydraulic fracturing stimulations, completed in Texas.

The data[15] shows only 12 incidents in Ohio related to failures of (or graduate erosions to) casing or cement – a failure rate of 0.03%**.** In Texas, the failure rate was only about 0.01%**.** Obviously zero is the aim, but this is still a very low percentage considering the large number of wells drilled.

A recent review by King and King (2013) of the data from 253,090 wells in Texas found that only 4 in every 100,000 (0.004%) wells constructed to modern standards experienced a loss of well integrity, compared to 0.2% for older wells.

The Queensland Gasfields Commission has released some information on well integrity in that state.[16] The cementing 'failure' rate after testing, remediation, and follow-up according to the Queensland code has been zero. The likelihood and therefore risk of a subsurface breach of well integrity is thus assessed to be very low to near zero.

- In July 2015, the Petroleum and Gas Inspectorate advised that from 2010 to March 2015, 6,734 CSG exploration, appraisal and production wells had been drilled in Queensland.
- According to the P&G Inspectorate, no leaks have been reported to date for subsurface equipment. This is consistent with recent scientific field measurements which found, in a sample of 43 wells "...no evidence of leakage of methane around the outside of well casings..." (Day et al, 2014: p2).
- There have been 21 statutory notifications (a rate of 0.3%) under the well construction code concerning suspect downhole cement quality during construction.
- For all of these 21 notifications, the gas companies followed up with subsequent testing to assess well integrity and undertake any remedial work.
- The P&G Inspectorate followed-up on all 21 notifications to ensure that the tests, and any required remediation work, conducted on the well was successful before gas production commenced, with the company also having appropriate monitoring programs in place to ensure ongoing integrity of the well.

[15] Kell, S. (2011), *State Oil and Gas Agency Groundwater Investigations and their Role in Advancing Regulatory Reforms: A Two-State Review: Ohio and Texas*, Ground Water Protection Council , fracfocus.org/sites/default/files/publications/state_oil__gas_agency_groundwater_investigations_optimized.pdf

[16] QLD Gasfields Commission (2016), *Well Integrity*. www.gasfieldscommissionqld.org.au/resources/gasfields/onshore-gas-well-integrity-in-qld.pdf

In 2015, the Western Australia Department of Mines and Petroleum (DMP) conducted a survey of 1035 non-decommissioned wells (both offshore and onshore wells) which found that: "*the vast majority of petroleum and geothermal wells are drilled, completed, produced and decommissioned without any adverse environmental impacts*".[17] DMP found that of the 953 active petroleum wells surveyed, 9% have had production tubing failures and 3% have had production casing failures well away from aquifers which were still protected by the surface and conductor casings. There have been no failures of surface or conductor casings.

[17] S Patel, S Webster & K Jonasson, *Review of well integrity in Western Australia*, Petroleum in Western Australia, April 2015, p 24

5. Hydraulic fracturing

Hydraulic fracturing is a distinct process from well drilling. A fracturing operation is performed on an already completed well. More information on well integrity can be found in section 3. In its most basic form, a hydraulic fracturing operation applies water at very high pressure at specifically targeted positions in a rock section to generate a contained fracture in the rock and stimulate production from a reservoir. [18]


The Canberra Times
Wednesday 2 August 1967, page 27

More oil near Alice Springs

A 130-barrels-a-day oil flow was reported yesterday from the East Mereenie No. 4 well in central Australia.

The East Mereenie No 4 well is about 140 miles west of Alice Springs.

Recovery of 36 barrels of oil and 45 barrels of oil was reported in May and June from earlier tests.

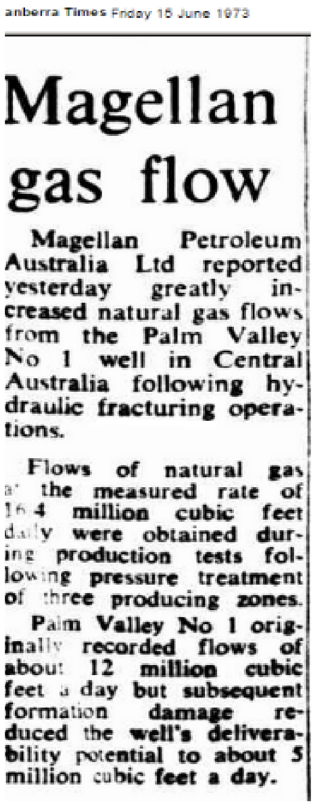
Partners in the well are Magellan Petroleum (50 per cent), Exoil (21 per cent), Transoil (9 per cent), Farmout Drillers (6½ per cent), and Krewliff Investments (13½ per cent).

A report from Exoil said the flow followed stimulation of the upper oil-bearing zones by fracturing.

The company said lower zones would be similarly treated to improve production.

Production tests would then be made on the combined upper and lower oil sands in the well.

[Fracturing of "tight" oil-bearing structures is done by applying strong pressure to special non-silting sand placed in the well. The sand is forced into cracks and keeps them open. This allows oil to flow. The process is being used successfully at Barrow Island, WA.]


anberra Times Friday 15 June 1973

Magellan gas flow

Magellan Petroleum Australia Ltd reported yesterday greatly increased natural gas flows from the Palm Valley No 1 well in Central Australia following hydraulic fracturing operations.

Flows of natural gas at the measured rate of 16.4 million cubic feet daily were obtained during production tests following pressure treatment of three producing zones.

Palm Valley No 1 originally recorded flows of about 12 million cubic feet a day but subsequent formation damage reduced the well's deliverability potential to about 5 million cubic feet a day.

Without hydraulic fracturing, shales will not produce gas in commercial quantities; with hydraulic fracturing, these same shales can produce vast quantities of clean, domestic natural gas.

Hydraulic fracturing and horizontal wells are not new tools for the oil and gas industry.

The first fracturing treatments took place in 1947, and the process was commercial by 1950. The first horizontal well was envisioned in the 1930s, and horizontal wells were common by the late 1970s.

Millions of hydraulic fracturing jobs have been undertaken, and tens of thousands of horizontal wells have been drilled worldwide during the past 60 years. The process has been safely used in over 1,500 wells in Australia since the 1960s.

In fact, some of Australia's first hydraulically fractured wells were in the Northern Territory. Reproduced here are two newspaper clippings demonstrating early hydraulic fracturing in the Northern Territory – 'More oil near Alice Springs', *Canberra Times*, 2 August 1967, and 'Magellan gas flow', *Canberra Times*, 15 June 1973. Both articles refer to hydraulic fracturing operations.

Hydraulic fracturing is well understood. It has been thoroughly researched – many universities, consortia, and public and private scientific organisations have studied fracturing.

More than 10,000 references have been published on rock mechanics, lab research, modelling, case studies, diagnostics, design, execution, and evaluation of hydraulic fractures in many types of rocks.[19]

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[18] See: www.fracfocus.org/hydraulic-fracturing-how-it-works/hydraulic-fracturing-process
[19] See: www.onepetro.org

5.1. Hydraulic fracturing basics

Creating the fractures: Hydraulic fracturing involves pumping water-based fluids down a well bore at high pressures and into specific, isolated sections of rock under carefully designed conditions. These fractures are usually a few millimetres wide, and can extend to more hundred meters from the well bore[20].

Keeping the fractures open: To hold the fractures open after the pumping has stopped, material such as sand (called proppant) is added to prop the fractures open against the pressure of the rocks. Some chemicals are added to neutralise any acidity; increase viscosity so the fluid carries more sand to the ends of the fractures; and to help maximise the flow back to the borehole.

Cleaning up the fractures: When the fracture is set, fluid is allowed to flow towards the well bore to clean up the fractures and establish the paths for the petroleum to travel to the bore hole.

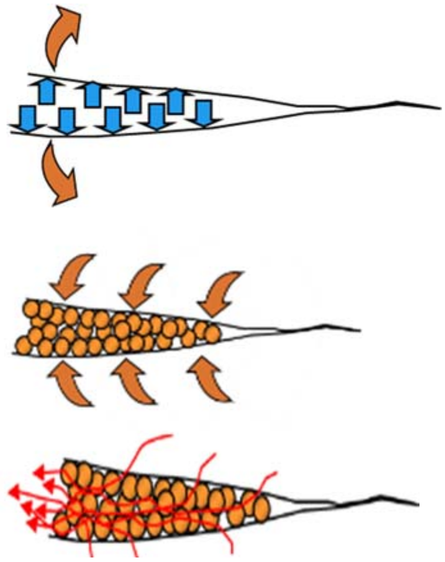
Figure 4 Frac Basics

5.2. Design inputs for hydraulic fracturing

Borehole measurements (or logs) and geologic models are used to assess the rock properties and select the appropriate fracture treatment based on the desired fracture containment, length and growth. The team measures the stiffness or elasticity of the rock at different depths, and the underground forces acting on each layer (known as 'in situ stresses').[21] Log-derived properties are used to identify the layer that has the least pressure. This will be the fracture initiation layer.

[20] Jeffrey, RG. (2012), *Hydraulic Fracturing for Coal Seam Gas (CSG) Stimulation in NSW*. CSIRO, Australia. Report EP122949, 15 pages.
[21] Nolte, K.G. and Smith M.B. (1981), *Interpretation of Fracturing Pressures*, paper SPE 8297-PA, www.onepetro.org

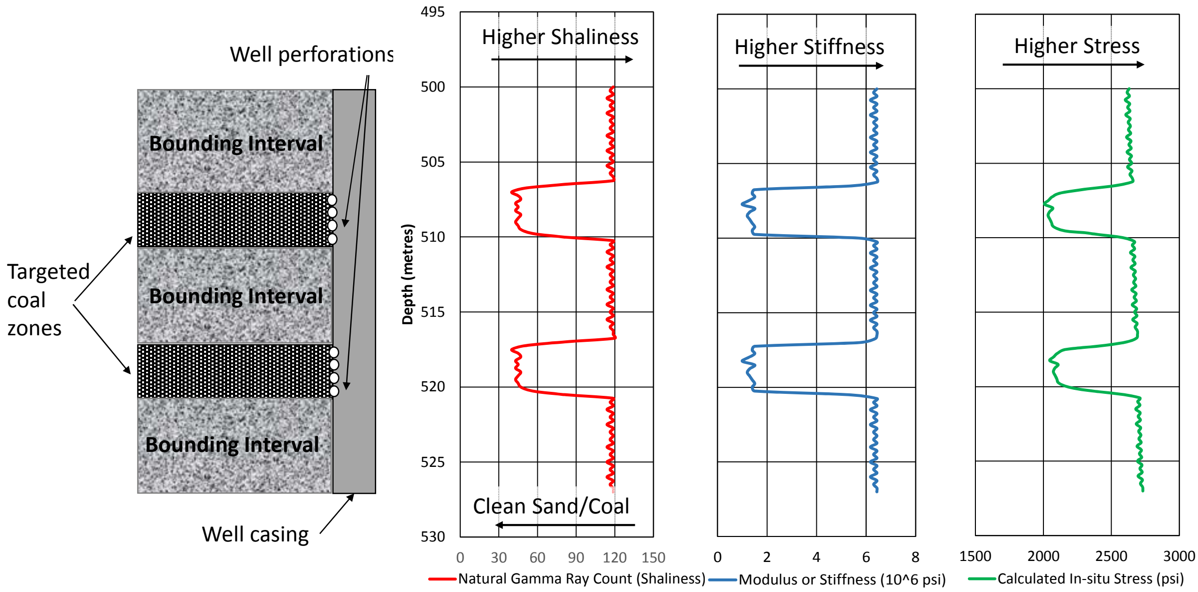

Figure 5 Representation of target interval selection for perforating based on log parameters such as amount of shale in the rocks (shaliness), modulus or stiffness, and in situ stress values.[22]

5.3. The hydraulic fracturing engineering design process

Based on decades of process optimisation, multi-disciplinary teams of petroleum professionals use several tools and processes to design a fracture and guide its successful implementation. The fracture design process includes several steps:

Developing geological models:

- A field geological and geomechanical model is based on geological data and previous wells.
- The geologist and petrophysicist update the models using measurements obtained when drilling the well to make a stress or stiffness log.

Testing well integrity:

- Well pressure integrity is assured by both the drilling and completion engineers pressure testing the casing and well head valves and, where applicable, running cement bond logs.
- Fracturing fluids are tested with the drilling cuttings or cores to achieve compatibility with the rock and protect the well using the minimum required additives.[23]

Detailed planning:

- Based on the logs the lowest stressed (least pressured) section of rock in the total section is targeted for stimulation. It is selected as the fracture start or initiation point and used as the basis of calibrating a hydraulic fracturing model, a process well known since the early 1980s.[24]
- The geologist, fracture engineer and reservoir engineer determine a diagnostics plan that lets them evaluate the fracture execution, and optimise future fracturing operations.

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[22] Crane, et al: *Fracturing Fluid Testing for Design Purposes and Regulatory Oversight in a Shale Gas Project*, SPE 167107, 2013.
[23] ibid
[24] Ajayi, B. et al, *Stimulation design for unconventional resources*, Oilfield Review, Summer 2013: 25, no. 2, www.slb.com/~/media/Files/resources/oilfield_review/ors13/sum13/04_stim_design.pdf

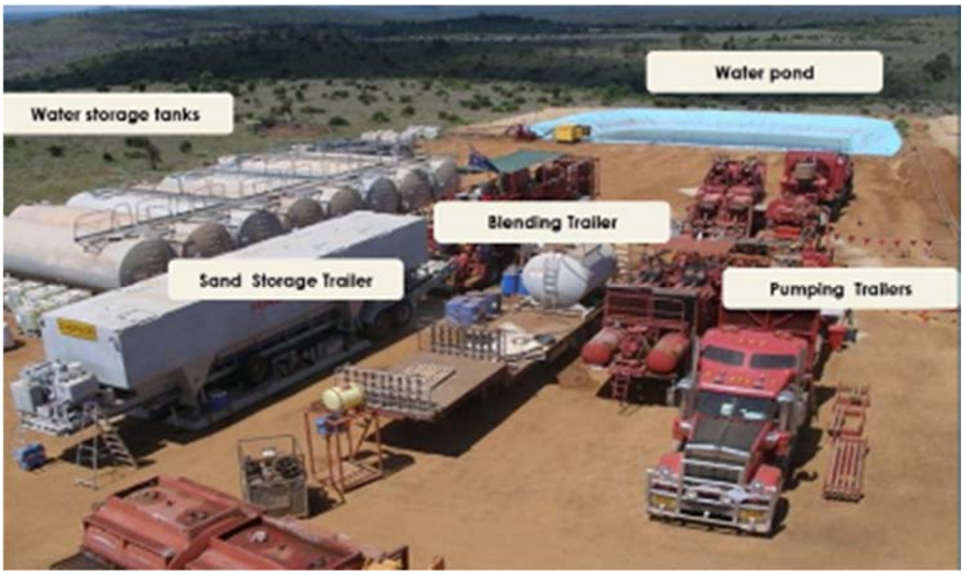
- The frac and completion engineers prepare a comprehensive operational plan that includes safety and environmental management plans and contingencies.

Since hydraulic fracturing is often the most expensive operation performed on a well, most companies have developed detailed processes and workflows to assure the design, execution and evaluation plans are well conceived and verifiable by field observations or diagnostics.

5.4. Execution is carefully monitored to ensure alignment with the design

Once the design has been finalised, the completion and fracture engineer manage the operational and technical execution on-site and:

- perform any additional pressure testing and verifications of wellhead integrity;
- verify the fracture model by performing initial injections in the desired rock section commonly known as a diagnostic fracture injection tests (DFIT) or "mini-fracs", and comparing (or 'history-matching') those results to the frac model predictions;[25]
- adjust the fracture design based on the mini-fracs, if history-matched results vary greatly from the model predictions; and
- execute the hydraulic fracture treatment using the fracture model history-match and diagnostics data collectged from the site.



Typical On-site Hydraulic Fracturing Operation (source QGC)

Wells are usually fractured in many places along the length of the well. The well is divided into a number of isolated sections, known as stages, which are then fractured individually. The number of sections (stages) depends on the length of the well, and can range from 1 up to 50 stages. The more stages a single well has, the less wells that are generally required.

Wells are fractured in stages to ensure fractures are created along the length of the bore (rather than only in the weakest area of the rock). To enable pressure containment within the desired area,

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[25] Johnson, et al. (2010) *Utilizing Current Technologies to Understand Permeability, Stress Azimuths and Magnitudes and their Impact on Hydraulic Fracturing Success in a Coal Seam Gas Reservoir*, SPE 133066.

a section of the well bore is closed off using packers. Once that section is fractured and propped, the completed stage is isolated to ensure that the next area is not affected by the previous stage.

5.4.1. Can you use non-potable or salt water in hydraulic fracturing?

Salt water can be used, depending on the reservoir chemistry. In many cases the minerals dissolved in seawater will have a negative effect on the process depending on the geology and the chemical compatibility. Salinity can drastically alter the effectiveness of the treatment chemicals. But in places where hydraulic fracturing is occurring near the ocean (California, for example), sea water can be used.

In Canada's Horn River gas shale, Apache Energy uses a closed-loop saltwater system, instead of fresh water, for fracture fluids. In other areas, industry is developing alternate water sources, such as saltwater from drilled formations. In the US most shale gas fields are far from the ocean so there is no local source of seawater, the cost of transporting saltwater means that this has not been taken up on a broad scale.

Petroleum companies usually drill water wells in non-potable aquifers (too deep and briny to drink) to provide all of their necessary water.

5.5. Low concentration chemicals are used to make the process more efficient [26]

Chemical additives are used in hydraulic fracturing for a wide range of purposes such as to:

- carry the proppant;
- reduce the friction between the water and the pipe or casing in the well;
- stop the growth of bacteria in the well and underground intervals;
- clean the well and increase permeability near the base of the well;
- prevent scaling, and
- remove oxygen to prevent corrosion of the casing.

Water and sand make up around 97 to 99 per cent of the fracture stimulation fluid. Added chemicals make up about 1 to 3 per cent. Fracture stimulation fluid mixtures are compatible and toxicologically safe for use in the petroleum-saturated reservoirs that constitute the fracture stimulation targets. The additives used are commonly occurring and widely used for a range of applications outside of hydraulic fracturing activities.

- **Water (>90%):** Water is the base fluid used to transmit the pressure from the pumps at the surface down to the rocks and efficiently open the cracks.
- **Gelling agent (<1%):** It is difficult to get water to carry all the sand right to the end of the fractures as the sand is about twice the density of the water. To enhance carrying capability, a 'gelling agent' is used to increase the viscosity. Guar gum (from guar beans) and cellulose gums (from plant fibres) are the most common gelling agents.

[26] King, George E. (2012), *Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells*, SPE 152596, fracfocus.org/sites/default/files/publications/hydraulic_fracturing_101.pdf.

- **Breakers (<1%):** Once the gelling agent has done its job carrying the proppant, it must be removed from the fractures or it will clog the cracks. Oxidizing or enzyme agents are injected to 'break down' the gelling agent's viscosity by degrading the gum's polymers. This allows the fluid to flow back to the well where most of it is brought back to surface for treatment or recycling.
- **Friction reducers (<1%):** Stable polyacrylamides are used to decrease fluid friction. This 'slickening' reduces the horsepower needed to pump the frac.
- **Surfactants (<1%):** These are added to help fluid recovery after the frac by reducing the surface tension of water. In liquid detergents and soaps surfactants are used to shift oil and grease.
- **Biocides (<1%):** These minimise biological contamination and bacterial infestation in the well, which could corrode the steel casing. The most common biocide, chlorine, is used in swimming pools and drinking water. Others are used in large air-conditioning systems or cooling towers.

Component	Volume	Purpose	Other uses
Water	>90%	Applies pressure to the rocks, and carries proppant into the fractures	Groundwater, surface water, or recycled water
Clay management (e.g. sodium and potassium salts)	< 1%	Minimises clay swelling or fluid interaction with the surrounding rock	Swimming pool salt, food additives, soil treatments
Gelling agents (e.g. guar or cellulose gums)	< 1%	Increases viscosity of fluid to carry more sand into the fractures	Cosmetics, ice cream, food thickeners, personal products
Breakers	< 1%	Breaks down the gelling agents after the proppant is carried into the rock fractures, enhancing gas flow and frac fluid recovery	Hair bleach, food additive, washing powder, enzyme products
Friction reducer	< 1%	Reduces friction of frac fluid, which decreases required pumping horsepower	Cosmetics, hair gel, drinking water and waste water treatments
Surfactants (eg alcohols, turpenes)	< 1%	Reduces fluid surface tension to aid fluid recovery and prevent emulsions forming	Soaps, detergents, household cleaners
Biocides	< 1%	Inhibits bacteria that could contaminate the frac fluid, rock or wellbore	Disinfectants, bleach, swimming pool chemicals
Corrosion and scale inhibitors	< 1%	Reduces corrosion of steel casing and the build-up of mineral precipitates in the well	Gelatine, swimming pool scale preventatives, instant coffee, detergents
Cross linkers (eg borate salts)	<1%	Links guar or cellulose polymers to enhance viscosity	Borax, laundry detergents, cleaners
Other stabilisers, buffers and acids (e.g. hydrochloric acid, sodium bicarbonate, acetic acid, sodium hydroxide)	< 1%	Maintains frac fluid stability by managing pH, iron control and reducing chlorine and other free radicals that could affect crosslinking of the polymers	Household cleaners, vinegar, baking soda, swimming pool pH and chlorine adjustors, aquarium chlorine remover

Many of the chemicals are now starting to be replaced with materials that are effective, but that will biodegrade or be completely consumed in their destruction of biological organisms. Some of the biocides and nonchemical approaches are also used in municipal drinking water. Other common fracturing biocides are used in hospitals and food preparation as well. These "greener" chemicals and nonchemical approaches are becoming more common.

5.6. Transparency of chemicals

Chemicals used in hydraulic fracturing can vary depending on geology, the treatment, and the operator. APPEA supports full disclosure of chemicals to the regulator and disclosure to the public where this would not affect intellectual property. APPEA recommends a "system-style" process of disclosure that lists all known chemical constituents in a fracturing fluid but decouples this from their parent additives. Industry is working with service providers to identify alternate, fully disclosable products that do not contain trade secrets.

The NT Government has already published details of the chemicals used in hydraulic fracturing. These should encourage leading practice and the use of innovative, environmentally benign chemicals. A website similar to www.FracFocus.org for Australian jurisdictions could provide a one-stop-shop for information on areas being explored for shale and tight gas and the chemicals used in each well. APPEA supports the NT Government's regulatory approach and welcomes discussion on how the regulationscan support both innovation and transparency.

5.7. Fluid management

The volume of hydraulic fracturing fluid used varies according to the rock being fractured, the depth of the well, and total stages per well. The US EPA found that historically hydraulic fracturing has averaged around 8ML of water per well, depending on the geology (see Table 1 Water use per hydraulically fractured well between January 2011 and February 2013. US EPA.).[27] The CSIRO estimates around 20ML of water for a shale gas operation. This variance in water usage is because well design is evolving to incorporate more fracture stages but with fewer wells drilled. The more stages a well has, the more water is required. A useful guide is approximately 1ML of water per stage and 1 ML of water for the drilling of the well.

Once fracturing has been completed and the pressure from pumping is reduced, water begins to flow back to the wellhead. This 'flow back' is a mix of the original hydraulic fracturing fluid – which is mostly water – and natural formation water. The formation water will contain dissolved constituents from the rock formation. Breakers added to the fluid reduce the polymers to smaller fragments or simple sugars. Sunlight generally degrades biocides to an inactive sulphate salt.

This fluid can be recycled and used to hydraulically fracture other wells. The quantity of water being recycled is increasing as companies become more familiar with handling waste on-site, water treatment technologies become more readily available and as chemical additives are improved. About 40-60% of the injected volume of fluid can be recovered. This is tested and can be filtered or treated. It is then:

- reused in other hydraulic fracturing treatments;
- mixed and treated with other production fluids; or
- allowed to evaporate with any solids disposed of in an appropriate disposal facility.

All operators plan fluid management as part of their environmental management plans. These plans are based on pre-frac tests, the likely interaction between the fraccing fluid and the rock, and the resulting fluid that will return to the surface after intermixing with rock formation fluids.

The industry is keen to work with the government in improving understanding of the NT's water resources. Oil and gas exploration often identifies new water resources or provides more information about known aquifers that could be of value to local landholders and others.

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[27] US EPA (2016) *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*

5.8. Diagnostic techniques optimise fracturing and identify opportunities for improvements

Computerised hydraulic fracturing models and pressure observations can help optimise fracture operations. New technologies such as short-lived radioactive tracers can also be used in the modelling process to better understand fracture height and length.

In the mid-1980s technological advances, such as surface and downhole deformation tiltmeters (or very sensitive inclinometer or level gauge) and micro-seismic monitoring, enabled development of the advanced 3D models the industry now uses.

A mixture of water and sand is pumped back into the well.

5.9. Hydraulic fracturing and aquifer protection

Typically, hundreds of metres of rock separate a fracture stimulation from any sensitive aquifers, such as those used for domestic or agricultural purposes.

The Australian Council of Learned Academics (ACOLA) has published a summary review of the risks associated with fracture stimulation and concluded that there is no evidence of hydraulic fracturing fluids moving up in the earth from a hydraulic fracturing operation to a surface aquifer. Recent studies of deep horizontal well fracturing indicate that it is impossible for induced fractures to travel through several thousand feet of rock.[28] , it demonstrates the significant distance between the well bores (blue) and hydraulic fracturing operations in the Cooper Basin.

Analyses of thousands of wells drilled in various shale gas basins, combined with models of fracture propagation in specific locales, demonstrate that vertical fractures encounter a number of barriers in the complexity and mechanics of layered sedimentary structures. Shale plays vary from basin to basin (and within a basin), including the maximum height of induced vertical fractures. The great majority of vertical fractures propagate several hundred feet, although a few – in the Barnett and Marcellus shales, for example – have vertical extensions of 1,000–1,500 feet and in some cases even more.

[28] Fisher and Warpinski (2012), *Hydraulic fracture height limits and fault interactions in tight oil and gas formations* onlinelibrary.wiley.com/doi/10.1002/grl.50707/pdf

Horizontal drilling and multistage hydraulic fracturing pose limited risks for groundwater contamination in and of themselves (King and King 2013). Surface activities present greater hazards either from gas leakage into the atmosphere or groundwater contamination associated with fracturing fluids and/or produced fluid handling at the surface.

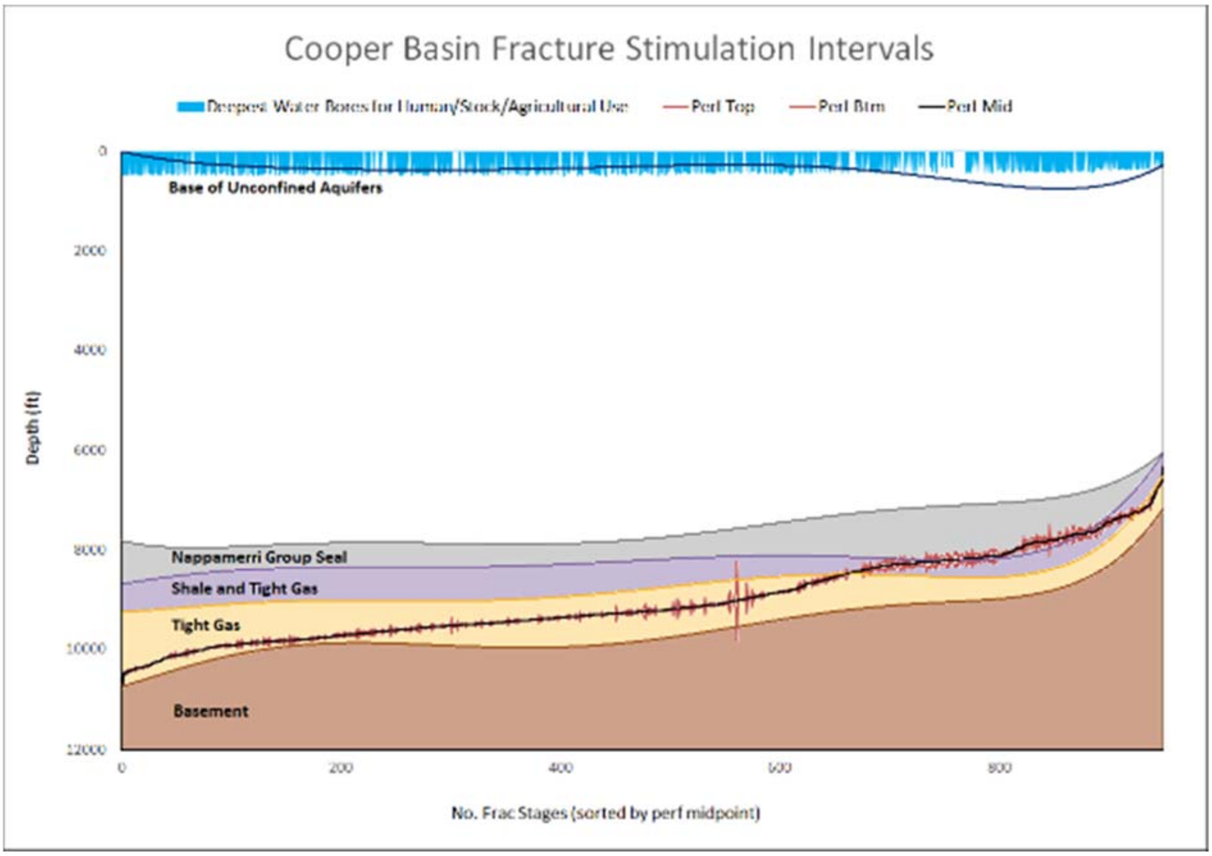


Figure 6 Separation of fracture stimulation in the Cooper Basin from fresh water supplies. Based on 716 fracture stimulated wells to end of August 2014.

Hydraulic fracture design, execution and evaluation began in 1949 as a process of empirical experimentation. By the mid-1980s it was a well-understood science that used the latest computational modelling tools and sensitive geotechnical diagnostics.[29]

Highly trained fracturing engineers specialise in this multi-disciplined process to assure that the most costly operation in a well's life targets only the desired section of the rock that can lead to the highest well productivity. For years, the industry has gathered valuable diagnostic data in a quest to better design, execute, and evaluate hydraulic fracture treatments.

[29] King, George E: "Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells," SPE 152596, http://fracfocus.org/sites/default/files/publications/hydraulic_fracturing_101.pdf, 2012.

5.10. Hydraulic fracturing and earthquakes

No correlation has been found between oil and gas activities in Australia and any earthquakes recorded by Geoscience Australia's Australian National Seismograph Network (ANSN).

Seismic events can be triggered by man-made activities – such as mining, dams and the extraction or injection of material below the ground.[30] This phenomenon is known as induced seismicity. These events have been reported in Australia, such as the 5.5 magnitude earthquake that occurred as a result of the Warragamba Reservoir filling with water. In this case, the weight of the water increased the stress on the ground over a widespread area and triggered the earthquake.[31]

Small seismic events have been known to result from stress changes in the ground due to oil and gas activities. NSW Chief Scientist Mary O'Kane stated that the "*possibility of induced earthquakes may be greater in the related process of wastewater disposal reinjection, especially when this is done at greater depths than for production."* It is important to note that these studies assess American shale plays where significant quantities of water is reinjected into deep aquifers. Wastewater. In a recent review of hydraulic fracturing and induced seismicity, Geosicence Australia found that "*the potential to induce earthquakes through the disposal of formation fluids down wells can be mitigated by proper management of formation pressures*." [32]

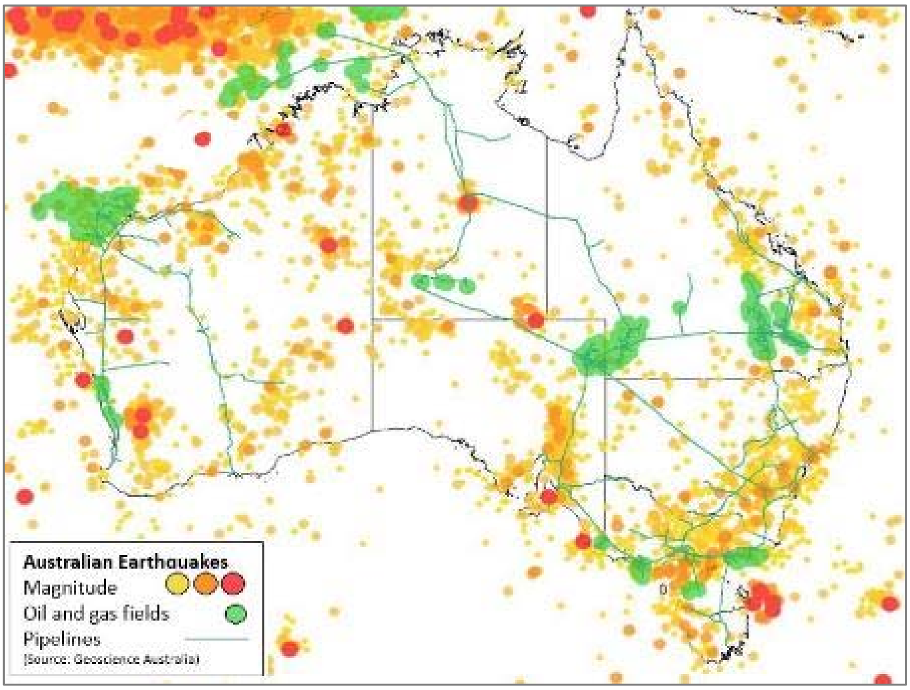


Image 13 Magnitude 4 and above earthquakes in Australia and oil and gas fields.

[30] See: www.src.com.au/earthquakes/seismology-101/dams-earthquakes/
[31] Gibson, G. (2013), *Earthquakes and Dams In Australia*, Australian Earthquake Engineering society http://www.aees.org.au/wp-content/uploads/2013/11/08-Gibson.pdf
[32] Drummond, B. 2016. *Review of Hydrofracturing and Induced Seismicity*. Record 2016/02. Geoscience Australia, Canberra. http://dx.doi.org/10.11636/Record.2016.002

Australian is a stable continent. Earthquakes are infrequent compared to those in plate boundary settings – such as parts of the US, and Pacific Rim countries to Australia's north. "*It is important to note that generally a site that is susceptible to induced earthquakes generally has a pre-existing susceptibility to natural earthquakes. This means that the earthquake that would have occurred eventually without any artificial trigger mechanism* (without being induced). (NSW Chief Scientist Mary O'Kane)

5.11. Studies into Hydraulic Fracturing

Numerous Australian and international reviews have found that the risks associated with hydraulic fracturing can be managed effectively with a robust regulatory regime.

For example, the Australian Government's Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development (IESC) commissioned a review by the Department of the Environment of hydraulic fracturing issues associated with coal seam gas extraction, including the techniques involved, the risks and how they are managed, and the regulatory environment. The review found that:

- Hydraulic fracturing is a long established process with significant international and Australian development in relation to regulation, including the restriction and management of chemicals, drilling and well construction processes.
- From an International perspective, there have been significant developments in the management and regulation of fracturing and this has influenced operators and procedures in Australia, as most of the contractors are large international organisations.
- International experience has shaped the regulatory framework.
- Risk assessments completed by industry for coal seam gas extraction projects suggest that hydraulic fracturing does not pose a significant risk to the environment, subject to implementation of controls and standards.
- The Queensland Environmental Authority conditions and the *NSW Code of Practice on Fracture Stimulation Activities* (NSW Trade & Investment 2012b) provide a good framework for the planning, execution and monitoring of hydraulic fracturing through a risk assessment process, specifically in relation to reporting of site-specific fracture analyses.

APPEA has also included a list of international studies into hydraulic fracturing at Appendix 3. Scientific and Technical reports.

Section 2. Response to Background and Issues Paper

The Background and Issues Paper released by the inquiry on 20 February 2017 identifies nine key risks areas. APPEA makes the following response to those risk areas.

Note: throughout this section of this submission, relevant excerpts from the Background and Issues Paper are reproduced before APPEA's response is detailed.

6. Water

Conservation and protection of groundwater and surface water is a top priority during all oil and gas activities. The use of chemicals during drilling, cementation and hydraulic fracture stimulation of wells is controlled, strictly regulated and carefully managed to minimise environmental risk. Studies and decades of practical experience show the risk of groundwater and surface water contamination is very low.

6.1. Water quality

Water quality	<u>Groundwater</u> There may be a risk of groundwater contamination as a result of: • induced connectivity between hydraulically fractured shale formations and overlying or underlying aquifers; • surface spills of chemicals, flowback water or produced water into near-surface groundwater; • leaky wells as a result of poor design, construction, operation or abandonment practices or as a result of well degradation over the life of the well; • re-injection of flowback water, produced water or treatment brines into a groundwater aquifer; and/or • induced connectivity between different groundwater systems as a result of seismic activity caused by hydraulic fracturing or reinjection of water.

The Australian petroleum industry focuses on conducting all aspects of its activities safely and sustainably. Conservation and protection of ground water is a priority. Environmental protection during oil and gas production is achieved by:

- Designing wells to standards that protect aquifers by ensuring multiple failsafe levels of protection;
- Isolating all fluids that might have a detrimental impact; and
- Being transparent and consulting with communities and government agencies before, during and after activities.

Numerous industry practices that are used in the Northern Territory to mitigate and reduce the risks of petroleum activities on water quality and quantity, as shown in Box 1 overleaf.

Box 1: Managing Water Quality and Quantity

- Detailed well design, testing and monitoring during all stages of well construction, hydraulic fracture stimulation, production testing, suspension, development and decommissioning.
- Monitoring local weather and climate information to make informed decisions regarding site operations.
- Ensure site environmental inductions for all site personnel and contractors include protective measures to prevent avoidable discharge into, or contamination of, waterways or established drainage systems.Ensure appropriate storage of fuel and other flammable and combustible liquids in accordance with "*AS1940:2004 The storage and handling of flammable and combustible liquids*".
- Maintain stormwater containment system as required.
- Have a procedure in place to manage large quantities of water. This may include pumping to an existing dam or watering point.
- Regular inspection and integrity checks of flowback tanks. Test tank integrity during commissioning and prior to use.
- All access roads, culverts and creek crossings will be maintained in proper working order.
- Ensure adequate freeboard is maintained in ponds to allow for a prolonged period of intense rainfall.
- Ensure all pipes and hoses are in good condition and fit for purpose to minimise risk of leaks from pipe.
- Ensure site environmental inductions for all site personnel and contractors includes the issue of water pollution and protective measures to prevent avoidable discharge into, or contamination of, waterways or established drainage systems.
- Maintenance of all water using utilities, such as toilets, showers to ensure in working order.
- Periodic visual inspections of the sites stormwater and waste water containment systems.
- Refuel and transfer chemicals away from drainage lines.
- Ensure site environmental inductions for all site personnel and contractors include protective measures to prevent avoidable discharge into, or contamination of, groundwater.
- Ensure site is equipped with spill clean-up equipment.
- Regular inspection and integrity checks of flowback tanks. Test tank integrity during commissioning and prior to use.
- Ensure well control critical equipment and systems on stimulation equipment are fit for purpose, certified, maintained in good working order and tested as required.
- Ensure appropriate well control training/certification for rig personnel.
- Pressure test verifying integrity of the string.
- Ensure sufficient distance between exploration targets and aquifers. Presence of natural frac barriers and high perm zones to contain fracture height growth.
- Continuous real-time pressure, rate and volume monitoring during HFS to stop pumping as soon as potential loss of containment identified.
- Ensure site environmental inductions for all site personnel and contractors includes the issue of groundwater pollution and protective measures to prevent avoidable discharge into, or contamination of, groundwater.
- Maintain all waste water systems in working order to minimise impact on groundwater.

6.2. Groundwater Contamination

The risk of contamination of aquifers by drilling or fracture stimulation fluids is very low, given the small volumes of chemicals used compared to the large volumes water present in the aquifer, and the multiple engineered containment barriers between the chemicals and the aquifer. These prevent any significant contamination from occurring. Multiple layers of steel casing and cement installed during the drilling process protect potable and non-potable aquifers. The well design ensures structural integrity within the wellbore to isolate the aquifers during stimulation, flowback operations and throughout the life of the well.

There are unsubstantiated claims about the potential risk of fractures propagating into aquifers. Based on current technology and geological data (including thousands of metres of sealing rock between these aquifers and the potential petroleum reservoir fracture stimulation targets), thereis very little risk that fracture propagation will lead to contamination of shallow aquifers.

Generally, the risks of aquifer contamination can be assessed on three levels:

1: Concentration and toxicity
The properties of the additives used in hydraulic fracturing are well known. The additives used are placed hundreds of meters beneath the surface, in very low concentrations (much lower than those used in swimming pools). Higher risks exist at the surface where the transportation, storage, and handling of chemicals must meet prescribed regulatory standards.

2: Likelihood that the chemicals remain in the ground
Drilling fluids are mostly returned to surface for proper disposal or recycling for reuse in the next well. Cementation chemicals are contained in the cement.
For fracture stimulation operations, 40% to 60% of the stimulation fluids return to surface as the well is flushed and cleaned out in the following weeks. This material is either disposed of through regulated facilities, or recycled. Over the life of the CSG well – which may be decades – the pressure gradient towards the well ensures that any chemicals that may be freed up over time are swept to the well and up to the surface for proper processing.

3: Likelihood the chemicals will migrate to uncontrolled areas
The volume of stimulation fluid is carefully calculated and monitored to ensure it cannot travel material distances from the well. Typically there are hundreds if not thousands of meters of rock between a fracture stimulation and any sensitive aquifers such as those used for domestic or agricultural purposes. This can be monitored with seismic or tracer technologies to verify the models for fluid travel.

The Australian Council of Learned Academies (ACOLA) has published a summary review of the risks associated with fracture stimulation[33] that concluded that there is no evidence of hydraulic fracturing fluids moving up in the earth from a fraccing operation to a surface aquifer.
ACOLA also noted research (Fisher and Warpinski[34] and Davies[35]) that showed the fracture stimulation treatments that travel the greatest vertical distance are those that break into natural

[33] Cooke. D. (2012), *A Brief Review of GeoScience Issues associated with Shale Gas development in Australia*, Australian Council of Learned Academies. www.acola.org.au/

[34] 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. (cited with Cooke, 2012)

[35] 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 (cited with Cooke, 2012)

faults. Davies cites a maximum fracture stimulation height of 588m for this type of stimulation treatment. However, ACOLA notes that there are several effective ways to prevent this from occurring or mitigate the effects, including:

- using 3D seismic measurements to map locations where fault risks exist and avoid fracture stimulation in the immediate vicinity; or
- geomechanical modelling to predict the susceptibility of different fault orientations to conduct fluids; or
- using microseismic technology to map in real time the growth of a fracture stimulation treatment and shut down the treatment if unwanted height growth is observed.

The ACOLA report also addresses concerns about contamination of the Great Artesian Basin by pointing out that those aquifers already contain numerous oil fields. For example, the Cooper Basin has more than 500 oil wells and has produced more than 160 million barrels of oil since 1982 without contamination.[36]

6.3. Surface water

Water quality	**Surface Water** There may be a risk of impacts on surface water quality as a result of the following types of incidents: • on-site spills, including as a result of extreme weather events such as cyclones and floods; • spills that occur during transportation of chemicals to or from the site during the development and production phases; and/or • spills of flowback water, produced water or brines produced by water treatment.

The management of water, chemicals and other substances on the surface is a key issue for the oil and gas industry. Proper handling of fluids that are returned to the surface is crucial. Once hydraulic fracturing fluids return to the surface, they are typically stored in tanks or lined pits to isolate them from soils and shallow groundwater zones. Conclusions from most studies into hydraulic fracturing have found that, overall, surface spills of fracturing fluids pose the greater risks to water than hydraulic fracturing itself.

These risks, such as water and chemical handling, are not unique to natural gas and are familiar in many industries. Possible sources of impact on water quality may include:

- accident with chemical spills when handling the fracturing fluid and flowback fluid;
- leakage of fluid through pipelines during flowback; and
- erosion and leaching from cuttings, drill mud.

Shale gas production involves use of fresh water, fracturing fluids, flowback water and produced water, chemicals and additives, as well as drilling muds and drill cuttings. The current best management approach is to minimise the amount of these materials on site, contain materials as fully as possible, reuse or recycle them to the greatest extent feasible, and dispose of the remainder offsite.

[36] 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: www.petroleum.dmitre.sa.gov.au/access_to_data/peps-sa_database (cited with Cooke, 2012)

Operators develop detailed waste management plans that consider all of the planned handling, treatment and disposal of waste. Best management practices are applied to avoid contaminating water supplies, bodies of standing water (e.g. lakes, swamps, etc.) and watercourses.

Oil and gas development and extreme weather

The oil and gas indistry fully considers the risks posed by flooding, high winds and other extreme weather events. The Australian industry has long experience of operating safely in flood-prone areas such as central Queensland and the Cooper Basin. Gas projects undertake full investigations of both 50 and 100 year ARI (Average recurrence interval) weather and regard is given to the historical weather patterns and climate extremes. In tropical areas, work is planned to coincide with the "dry season" and mitigation measures, such as site stormwater management systems, waste containment systems, and infrastructure design ensure personnel and the environment are protected.

This sort of design is standard and the Australian petroleum industry has developed close working relationships with agencies such as CSIRO and the Buereau of Meteorology to understand and mitigate against weather events.

6.4. Water Quantity

Water supply and distribution (quantity)	There may be a risk of adverse environmental impacts (including those listed in this table) as a result of reduced water supply due to the large amounts of water being extracted for use in hydraulic fracturing. There may be a risk of changes to the timing and/or quantity of surface water flows because of the discharge of produced water, which may be significant particularly in arid to semi-arid landscapes. There may be a risk to surface water and groundwater flow processes as the result of possible seismic activity caused by hydraulic fracturing or reinjection of water.

Most of the water used in tight and shale gas production is used in the hydraulic fracturing process with quantities varying depending on local geological conditions, such as depths, porosity and the length and number of horizontal wells.

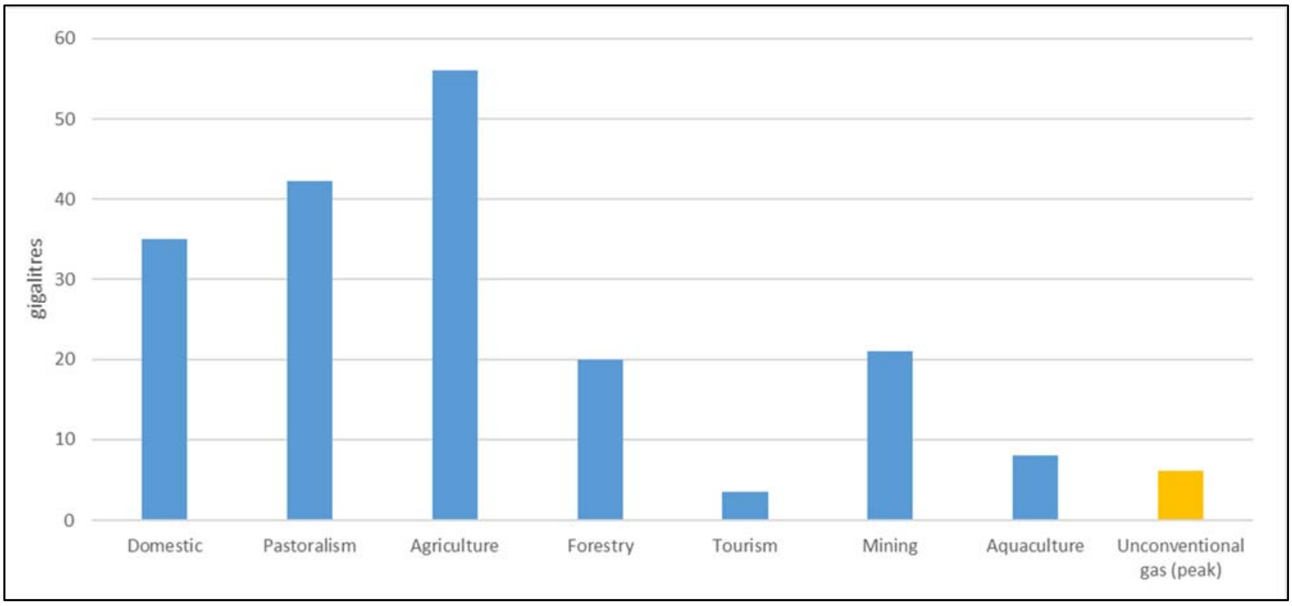
Water is generally obtained within the vicinity of operations and is typically brackish (i.e. not potable). Companies are committed to minimising their footprint and water used in hydraulic fracturing operations will be captured and reused where possible. Salt water can be used in hydraulic fracturing operations and some operators (such as Apache Energy in Canada) use salt water closed-cycle systems.

As noted in the Background and Issues Paper, petroleum activities are currently exempt from the application of the *Water Act 1992* (NT). As part of the existing approvals process, the DPIR requires that a company must demonstrate that the taking of water will not have unacceptable impacts on aquifers. The industry fully supports the removal of the *Water Act 1992* (NT) exemption, provided that this does not lead to a duplication of regulation by both the DPIR and Department of Environment and Natural Resources.

The IGU estimates that between 11 and 19 million litres (ML) of water – equivalent to four Olympic swimming pools – is required to fracture a well[37]. Water requirements per well depend on the depth and length of the well and the number of fracture stages performed. The ACOLA Report notes that while water requirements might be large when considered independently, they are "modest when set against consumption in irrigated agriculture."[38]

6.4.1. Northern Territory Water Consumption

APPEA has commissioned a study by Northern Territory based EcOz Environmental Consulting to consider the water consumption in the Northern Territory. This report will be submitted to the inquiry. Generally the water required for hydraulic fracturing is much lower than the water requirements of other industries.



Graph comparing estimated annual water use (by industry) in the NT

Source: EcOz Environmental.

The construction, development and operations phases will have additional water requirements typical of those for a large-scale development in the region – but these are not expected to exceed a few megalitres per year.

The report found that each year, around two million gigalitres (GL) of rain falls on northern Australia (including northern Queensland and Western Australia). Up to 90 % of this evaporates before it can be used (Stone & Chilcott 2016). Of the remaining 10 %, less than 2 % enters groundwater (Stone & Chilcott 2016). Aquifers supply up to 90% of the water used by industry and the community in the NT (Harrington & Cook 2014).

According to the Australian Bureau of Statistics, the NT consumed 153 GL of water in 2014-15, a decrease of 8.5 % from 2013-14 (ABS 2016). Households in the NT consumed about 35 GL of water

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[37] *International Gas Union, (2012), Shale Gas: The Facts About Environmental Concerns,* *www.igu.org/gas-knowhow/publications/igu-publications/UG20120064_IGU_ShaleBooklet_Final_forWeb1.pdf*

[38] Cook, P, Beck, V, Brereton, D, Clark, R, Fisher, B, Kentish, S, Toomey, J and Williams, J (2013). *Engineering Energy: Unconventional Gas Production*. Australian Council of Learned Academies (ACOLA), www.acola.org.au

in 2014-15, accounting for 22.9% of total water consumption. Other major uses are discussed below.

For the various companies involved in gas exploration in the Beetaloo Basin, approximately 47 ML of water is expected to be required to drill and stimulate each well. The stimulation component is about half of this requirement, and there is a level of recovery and reuse of that water which is not accounted for in this figure.

Water use in the Northern Territory is regulated under the *Water Act.* The Act allows the enforceable allocation of water to various declared beneficial uses – including agriculture, aquaculture, public water supply and industry – while ensuring that adequate provisions are made to maintain cultural and environmental requirements. Notable exemptions currently apply to the petroleum and mining industries, which are not required to hold water licenses and permits for the extraction of surface and groundwater under the *Water Act.* Likewise, a water licence is not required for use of water (groundwater or surface water) for pastoralism (i.e. watering animals). As noted above, the oil and gas industry fully supports the removal of the *Water Act 1992* (NT) exemption, provided that this does not lead to a duplication of regulation by both the DPIR and Department of Environment and Natural Resources.

Estimated annual volume of water consumption (by industry) in the NT

Industry	Annual water consumption (GL)^
Domestic	35.0
Pastoralism†	42.3
Agriculture	56.0
Forestry*	20.0
Tourism	3.6
Mining	21.0
Aquaculture**	8.0
TOTAL* **	**185.9**
Unconventional gas (peak)	6.2

Amount of water used for hydraulic fracturing

The amount of water required for hydraulic fracturing varies as a result of geology. As a general rule of thumb the industry expects to use 1 ML of water for drilling and completions and an additional 1 ML per hydraulic fracturing stage. In 2016 the US EPA undertook an analysis of water use per hydraulically fractured well between January 2011 and February 2013. The water usage varied from less than half a megalitre (in California) to 30ML (in Lousiana). The average volume across all wells was 8.5 ML. The CSIRO estimates around 20 ML is used per well for hydraulic fracturing in Australia. Wells with more fracturing stages will use more water per well, but less wells are required and water use is not expected to be higher in these circumstances.

Table 1 Water use per hydraulically fractured well between January 2011 and February 2013. US EPA.

State	Number of FracFocus 1.0 Disclosures	Average Volume per Well (Megalitres)	10th percentile (Megalitres)	90th percentile (Megalitres)
Arkansas	1,423	19.91	12.25	26.96
California	711	0.29	0.08	1.08
Colorado	4,898	1.75	0.56	11.70
Kansas	121	5.50	0.04	8.43
Louisiana	966	19.22	6.86	30.08
Montana	207	5.51	1.39	11.35
New Mexico	1,145	0.66	0.13	7.09
North Dakota	2,109	7.66	3.67	12.54
Ohio	146	14.72	10.92	21.09
Oklahoma	1,783	9.81	4.77	28.02
Pennsylvania	2,445	15.84	8.76	25.04
Texas	16,882	5.38	0.22	23.15
Utah	1,406	1.14	0.29	2.91
West Virginia	273	18.97	12.00	27.62
Wyoming	1,405	1.22	0.02	6.96
Total	35,920	8.51	4.13	16.27

6.5. Aquatic ecosystems and biodiversity

Aquatic ecosystems and biodiversity	There may be a risk of adverse impacts on aquatic ecosystems and biodiversity, including groundwater dependent ecosystems. This may result from changes in the quality and/or quantity of surface and/or ground water available to them.

As noted above, proponents closely manage the supply of water, storage, containment and disposal of recovered stimulation fluid through robust operating practices. With effective environmental management procedures, the risk to aquatic ecosystems is considered low.

The main event likely to affect aquatic ecosystems during the development of a project is sediment and nutrient mobilisation. The most likely causes of sediment mobilisation is generally earthworks (clearing etc) that occurs adjacent to watercourses. These impacts are well known and managed and particular care is taken more severe in habitats characterised by lower turbidity as fauna and flora in these habitats are adapted to clear-water conditions.

There is no evidence to suggest that onshore gas activities impact significantly on aquatic ecosystems and biodiversity.

6.6. Amenity values

Amenity values	There may be adverse impacts on general amenity values such as national parks, rangelands and recreational fishing areas. This may result from changes in the quality and/or quantity of water available.

With appropriate well design and protection in place, risks and mitigation in relation to impacts on water from shale gas should primarily focus on reinjection and impacts at the surface.[39] These activities are strictly regulated and companies are required to address the management of water at the surface and disposal in an Environment Management Plan.

Proponents manage the supply of water, storage, containment and disposal of recovered stimulation fluid appropriate to their environmental setting. In many locations, water that cannot be recycled is placed in specially designed ponds for evaporation. The residue from this process is tested and, if required, safely removed to a licensed disposal facility. At no point does this water contact groundwater sources.

The industry is keen to work with the government in improving understanding of the NT's water resources. Oil and gas exploration often identifies new water resources or provides more information about known aquifers that could be of value to local landholders and others.

6.7. Public health

Public health	There may be adverse impacts on human and livestock health due to changes to water quality, supply and distribution as a result of hydraulic fracturing and the associated activities.

The Western Australian (WA) Department of Health (DoH) conducted a detailed scientific study of the health risks on drinking water from activities associated with hydraulic fracturing of shale gas reserves in WA[40].

The report found that, under the right conditions, hydraulic fracturing of shale gas reserves can be successfully undertaken without compromising drinking water sources. The WA DoH concluded that the risks to drinking water sources associated with hydraulic fracturing can be well managed through agreed industry and engineering standards, best practice regulation, appropriate site selection and monitoring of the drinking water source.

As noted above, proponents manage the supply of water, storage, containment and disposal of recovered fluids through robust operating practices.

[39] Cook, P, Beck, V, Brereton, D, Clark, R, Fisher, B, Kentish, S, Toomey, J and Williams, J (2013). *'Engineering Energy: Unconventional Gas Production.'* Australian Council of Learned Academies (ACOLA), www.acola.org.au.

[40] Government of Western Australia (2015), *Hydraulic Fracturing for Shale and Tight Gas in Western Australian Drinking Water Supply Areas: Human Health Risk Assessment*, Department of Health, ww2.health.wa.gov.au/Reports-and-publications/Hydraulic-fracturing-for-shale-and-tight-gas-in-Western-Australian-drinking-water-supply-areas

6.8. Aboriginal people and their culture

Aboriginal people and their culture	Natural water bodies are central to traditional land use and many sites of significance to Aboriginal people relate to water. A reduction in either water quantity or quality may impair the traditional use and/or value of the sites.

The industry is keen to work with government and other users and custodians of water to improve understanding of the NT's water resources. Oil and gas exploration often identifies new water resources or provides more information about known aquifers that could help stakeholders.

Box 2 highlights common industry practices to manage cultural heritage risks:

Box 2: Managing Cultural Heritage Risks

- Site inductions are conducted to ensure that all personnel are aware of cultural awareness obligations.
- Adhering to regulations applying to the area, including specific conditions on the exploration permits and agreements with the relevant Land Council.
- Adhering to and monitoring conditions outlined in Aboriginal Areas Protection Authority (AAPA) Authority Certificates.
- Ensuring all site personnel and contractors are aware of any potential Restricted Work Areas (RWAs) and conditions outlined in the AAPA Certificates.
- Brief personnel on the rules and regulations and disciplinary measures for breaches of the RWAs.
- Considerations and special procedures to be used for protection of archaeological and cultural sites in the define work areas.
- Work practices that avoid or minimise impacts – particularly for operators of machinery such as graders and dozers.
- Ensuring that site personnel and contractors report all new discoveries of archaeological or cultural artefacts. In these circumstances, work ceases and practical protection measures are put in place until the area can be assessed by relevant NT Government personnel.

6.9. Economic

Economic	Changes to water quality, supply and distribution may have an adverse impact on industries that may co-exist with the onshore unconventional gas industry, such as agriculture, pastoralism and tourism.

The onshore gas industry is and will remain a very small user of the NT's water resources compared to co-existing industries such as agriculture, pastoralism and tourism. Oil and gas proponents manage the supply of water, storage, containment and disposal of recovered stimulation fluid appropriate to their environmental setting. Oil and gas exploration often identifies new water resources or provides more information about known aquifers that could be of value to local landholders and others.

Water is recycled where possible. Water that cannot be recycled is placed in specially designed ponds for evaporation. The residue from this process is tested and, if required, safely removed to a licensed disposal facility in accordance with NT, State and Commonwealth regulations.

6.10. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

While APPEA argues any and all risks to water resources associated with our industry are small and manageable, clearly the risks of adverse impacts will be proportionate to the scale of the activities undertaken.

The industry is keen to work with the government in improving understanding of the cumulative impacts of petroleum activities in the NT.

7. Land

Drilling a shale gas well in Australia is very expensive, often costing about $20 million. Operators are therefore very careful in how they plan and execute drilling.

In the current early stage of exploration, companies will primarily rely on vertical wells. As the industry moves towards commercial production, producers will use horizontal drilling. This makes operations more efficient and allows for the drilling of multiple wells from a single drill pad, limiting surface disturbance.

Horizontal drilling involves drilling down to a target depth and then turning and drilling horizontally, usually to a distance of 1-3 kilometres. This practice increases the amount of rock in contact with the well and increases the gas production rate, thereby decreasing the number of wells required.

Typically 6-12 horizontal wells can be drilled from a single surface location or 'pad', which concentrates all activities into an area of about a hectare, thereby minimising surface disturbance.

As the International Gas Union (IGU) notes, shale gas production requires a much smaller footprint than conventional natural gas drilling and other forms of energy production. [41]

While pads with multiple wells are likely to require more land than a pad for a single well, it has been found that this extra land use would more than offset the fewer well pads required overall.

[41] International Gas Union (2012), *Shale Gas: The Facts About Environmental Concerns,* www.igu.org/gasknowhow/publications/igu-publications/UG20120064_IGU_ShaleBooklet_Final_forWeb1.pdf

A pad containing between four and eight wells is expected to cover less than the size of a standard house block after land rehabilitation. In a development where multiple pads are used to commercialise a field, these pads would be placed between one and four kilometres apart.

To reinforce this assessment, ACOLA states, "*overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells*."[42] These levels of land disturbance are also expected to be lower than those associated with agriculture or urban development.[43]

Strategic planning for coexistence of industries should seek to take into account the impact of all activities and how they can minimise their total land disturbance.

After a well is established and a project moves from exploration to production, most of the land is rehabilitated around each well pad and the associated infrastructure.

Each well head will have a two metre tall 'Christmas Tree' – or valve assembly – to control the gas production. These well pads would typically be spaced between one and three kilometres apart across a production area. The number of wells and well pads will depend on the nature of the reservoir rocks identified by exploration programs and production history of the wells.

Planning for multiple land uses to ensure coexistence of potential shale gas activities with existing activities will be very important to industry and landowners.

All sites affected by operations are rehabilitated as close to their original condition as possible. As per the *Petroleum (Environment) Regulations 2016,* companies are required to identify in their approved Environment Plan how land will be rehabilitated after the conclusion of all relevant activities. Companies are also required to report the progress of rehabilitation efforts to DPIR on a regular basis.

Once production is exhausted the operator will permanently seal the well with cement plugs – a process called abandonment. All cements used in operations are specially formulated to withstand high pressures and last for decades.[44] The abandonment process is subject to strict conditions and a company's process is reviewed and approved by DPIR.

[42] Cook, P, Beck, V, Brereton, D, Clark, R, Fisher, B, Kentish, S, Toomey, J and Williams, J (2013). *Engineering Energy: Unconventional Gas Production*. Report for the Australian Council of Learned Academies, www.acola.org.au.

[44] ibid

7.1. Terrestrial ecosystems and biodiversity

Terrestrial ecosystems and biodiversity	There may be a risk that hydraulic fracturing and the associated activities will have an adverse impact on terrestrial ecosystems and biodiversity in the Northern Territory. Specifically, there may be: • a risk of vegetation loss on a local scale as a result of areas being cleared for roads, pipelines and drill pads or as a result of spills; • a risk of loss and/or fragmentation of habitat for fauna on a regional scale as a result of road and pipeline construction and operation; • a risk of adverse impacts on terrestrial ecosystems, including fauna and flora, as a result of changes to water quality and availability; • a risk of weed invasion as a result of increased traffic; • impacts on biodiversity and greenhouse gas emissions due to changed fire regimes; and • a risk of adverse impacts on fauna as a result of increased noise and light from petroleum operations.

While exploration takes place over large areas, the actual development of any potential project in the Northern Territory would take place over a small land area.

APPEA members use sensitivity mapping and landscape management guidelines to plan the location of infrastructure, taking into account the landscape biodiversity values.

The industry aims to minimise adverse environmental impacts to terrestrial ecosystems and to enhancing environmental benefits associated with activities, products or services; conserving, protecting, and enhancing where the opportunity exists, the biodiversity values and water resources.

Where potential impacts are identified, mitigation measures or offsets are determined to reduce risks to acceptable levels.

These measures include the protection of high biodiversity values and related potential impacts across the diverse terrestrial, aquatic, coastal and marine ecosystems.

Origin energy has undertaken a preliminary estimate of the disturbance associated with each well pad is 14 ha (0.14 km^2).

This area includes disturbance for: the well pad, pipeline connections and access roads. Based on a forecast of about 50 well pads within the Development Area, the total disturbance area per Development Area over the life of the Project is 700 ha.

Cleared areas which are no longer required for operational purposes will be rehabilitated. Rehabilitation strategies are typically based on assisted natural regeneration, which combines natural regeneration from locally collected native seed and soil, to enhance germination success.

The oil and gas industry has in place a host of mitigation measures and practices designed to minimise and/or eliminate risks of activities affecting terrestrial ecosystems and biodiversity. For water quality and quantity, these measures have been outlined above.

Box 3 – overleaf – outlines industry practices designed to minimise and/or eliminate risks to terrestrial ecosystems and biodiversity.

Box 3: Industry practices designed to minimise and/or eliminate risks on terrestrial ecosystems and biodiversity

Noise and vibration

- Ensure site environmental inductions for all site personnel and contractors include the issue of noise, vibration and light and protective measures to prevent disturbance.
- Existing noise attenuation devices fitted to drill rig and other machinery used on site will be maintained in good working order.
- Lighting used on drill site to minimise offsite disturbance, while maintaining safety standards.
- Existing noise attenuating devices fitted to camp equipment, such as generators used on site will be maintained in good working order.
- Lighting used on camp site to minimise offsite disturbance, while maintaining safety standards.

Visual amenity

- Locate in area that minimises visual impact as far as practicable
- The degree of light spread and potential impacts on landowners should be considered
- Minimise visual impact, by deviations around topographical features or stands of vegetation, doglegs at road crossings, where feasible.
- Position major infrastructure away from roads.

Vegetation and Flora

- Ensure site environmental inductions for all site personnel and contractors include the management of onsite vegetation and flora, including personnel to only use access tracks and vehicle weed hygiene requirements.
- Stay within designated access roads and work areas.

Weeds

- Site inductions are to ensure that all personnel are aware of vehicle weed hygiene requirements and staying on designated access tracks.
- Ensure vehicles, machinery and equipment entering the permit areas have been cleaned and are free of vegetative matter, or have a valid weed hygiene certificate in accordance with Origin's Vehicle and Mobile Plant Weed Hygiene Procedure (OEUP-1000-PRO-ENV-025).
- All vehicle, equipment and rig movements to stay on formed access tracks, well leases and camp areas.

Fauna Habitat

- Site inductions are to ensure that all personnel are aware their obligations and the correct procedures for fauna encounters.
- Minimise vehicle movements during dawn and dusk.
- Restrict vehicle movement to existing or specifically designated access roads and impose suitable speed limits.
- Lease pad to be stock fenced.
- Ensure waste is managed correctly so as not to attract fauna.
- Site inductions are to ensure that all personnel are aware their obligations and the correct procedures for fauna encounters.
- Employees will be prohibited from bringing firearms, traps and domestic animals into lease area.
- Avoid interactions with fauna where practicable.
- Ensure waste is managed correctly so as not to attract fauna.
- The workforce will be prohibited from bringing domestic animals into the lease area (recognising that pastoralists don't need to comply with this instruction).
- Restrict vehicle movement to existing or specifically designated access roads and impose suitable speed limits.

Feral animals and other pest species

- No rubbish (i.e. food packaging) to be left on sites.
- Domestic refuse will be disposed of in accordance with NT waste guidelines.
- Ensure waste is managed correctly so as not to attract fauna.
- Wastes will be stored in dedicated waste storage areas.

Bush Fires

- Site inductions must ensure all personnel are aware of designated smoking areas and hot work permit requirements.
- Fire or unprotected flame must be kept at least 45 m from unprotected sources of flammable vapour.
- Storage of fuel and other flammable and combustible liquids must comply with AS1940:2004 *The storage and handling of flammable and combustible liquids.*
- Smoking only allowed in designated areas.
- Acquire a work permit before proceeding with any hotwork activity.
- Whenever hotwork activities are undertaken, the area surrounding the work site should be cleared combustible materials and appropriate firefighting equipment kept on hand during such operations.
- Hazardous area diagram for drilling rig is to be developed and implemented.
- Diesel engines must not be used within 15m of a well or other source of flammable vapour unless fitted out appropriately.
- Where safe to do so attempt to put out natural fires in the vicinity of operational areas.
- Fit all fixed engines operating at drilling site with adequate spark arrestor and emergency shut-down devices.
- A flare pit shall be sited and constructed so as not to create a hazard to property of natural vegetation.
- Firefighting equipment should be signposted, accessible and ready for operations.
- Remove any rubbish, debris or oil refuse that could constitute a fire hazard to a safe distance away from all buildings and installations, wells and production facilities.
- Fire breaks to be maintained around the camp (minimum of 4m wide).

7.2. Soil health

Soil health	There may be a risk that the chemicals used in the drilling and hydraulic fracturing process will have an adverse impact on soil health, including as a result of spills of flowback water.

The risk of site contamination associated with a gas development) is similar to other commercial developments. Standard industry controls ensure activities do not affect soil health. The majority of chemicals pose little threat to soil health and will rapidly biodegrade.

Box 4: Ensuring Soil Health

- Ensure site environmental inductions for all site personnel and contractors include the requirement to use only approved access.
- Monitor and maintain sediment fences around lease pad and camp, in accordance with erosion and sediment control plans.
- Monitor lease pad and road conditions and implement management measures where required.
- Use only approved access tracks and established designated parking and vehicle movement areas.
- Ensure site environmental inductions for all site personnel and contractors include the requirement to use only approved access tracks.
- Infrastructure is located where there is minimal risk to sensitive receptors (water courses, public places etc.).
- Flow back storage structures (ponds or tanks) are designed to fully contain fluid. Reliable leak detection system and groundwater monitoring infrastructure

7.3. Aboriginal people and their culture

Aboriginal people and their culture	The landscape, terrestrial ecosystems, plants and animals are central to traditional cultural values. Adverse impacts to these things may have an adverse impact on Aboriginal cultural values.

The industry respects the cultural values of Aboriginal people and the importance placed on the landscape, ecosystems, flora and fauna that are central to these values. Industry practices that address risks to cultural heritage are addressed in the Aboriginal People and their Culture section.

7.4. Economic

Economic	An adverse impact on terrestrial ecosystems may be a risk to industries that co-exist with the onshore unconventional gas industry, such as agriculture, pastoralism, fisheries and tourism.

Long-term co-existence with other activities permited on land where petroleum activities take place is critical for the sustainability of the NT economy. Activities that derive economic benefits from the NT landscape include mining, agriculture, pastoralism, fisheries and tourism. Industry practices that address risks to activities that derive economic benefits from terrestrial ecosystems have been addressed in Boxes 1, 3 & 4 above. Independent evidence from Queensland and South Australia shows the established industries have not be disadvantaged by the development of the natural gas industry.

7.5. Amenity values

Amenity values	The Panel recognises that the Northern Territory has iconic wilderness values as a core part of the Australian outback. There may be a risk that the development of the unconventional gas industry will have an adverse impact on the outback experience (for example, tourism) through infrastructure development (for example, the construction of pipelines and processing plants), and increased traffic, noise and light (from flaring).

The NT outback experience is one that attracts not only domestic and international tourists, but also short and long-term residents to the Territory. The outback supports residential communities, cultural heritage, recreational and economic activities.

Industry practices that address risks to the amenity values of the outback have been addressed in Boxes 1, 3 & 4 above.

7.6. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

The industry aims to work cooperatively with communities, governments and other stakeholders to achieve positive social and environmental outcomes, seeking partnership approaches where appropriate.

The industry has specific measures in place to minimise each of the risks identified. These measures are based on very conservative assessments to effectiviely eliminate risk or manage risks to very low probabilities. As part of its planning and approval processes, the industry considers all other existing and committed projects, and addresses any cumulative impacts.

8. Air

Air quality is an important consideration in the construction and decommissioning phases of any project. The creation of new roads, for instance, may contribute to increased levels of dust or other particulate matter. Air emissions from agricultural activities will generally consist of dust from cultivation and harvesting activities, exhaust emissions from farm machinery, and greenhouse gases from cattle grazing.

Potential operational impacts from the gas industry are primarily associated with a development scenario that includes emissions from plant and equipment. Compressor Stations, in particular, can be associated with emissions from power generation (such as carbon monoxide). These issues are covered in detail in EIS and other impact assessments.

A summary of actions undertaken by the industry to address air quality are summarised in Box 5 overleaf.

Box 5: Air Quality

- Ensure site environmental inductions for all site personnel and contractors include protective measures to control or report air emissions and fire prevention, including smoking and hot work in designated areas.
- All vehicles and equipment used on site will be well maintained with mufflers fitted, in accordance with NT Work Safe requirements and/or Motor Vehicle Registration requirements.
- All access roads, culverts and creek crossings will be maintained in proper working order.
- Use water truck where applicable to manage dust emissions from vehicle movement or drilling operations on the site.
- Keep flaring to a minimum length of time necessary to determine resource and production parameters.
- Monitor gas volumes and report to the DPIR.
- Pressure test all surface equipment during commissioning to minimise the potential of fugitive emissions at surface.
- Potential fugitive emissions, as a result of migration along the well bore, are mitigated by constructing the well to company standards and industry best practices. These require the presence of cemented casing strings, assessment of the cement quality with logging tools and monitoring the well during flowback.
- Minimise vehicle movement to that necessary in the camp area.
- Use water truck where applicable to manage dust emissions from vehicle movement.

8.1. Public health

Public health	The possible health risks associated with the release of gases from the hydraulic fracturing process are discussed below in "Public health".

According to Public Health England, the currently available evidence indicates that the potential risks to public health from exposure to the emissions associated with shale gas extraction are low.[45]

The Public Health England (PHE) assess the *potential* risks from emissions of chemical and radiological pollutants from shale gas extraction, based on the likelihood of harm resulting from exposure to the hazard. PHE uses a common model for assessing risks: the source-pathway-receptor model in which hazards are identified, such as potential contamination of air or water (source), allied to consideration of their fate and behaviour in the environment (pathways) and the presence of any populations that may be exposed (receptors). The review details the potential hazards from emissions of chemical and radiological pollutants andevaluates the associated risks.

The review observed that experiences from countries with commercial-scale operations, particularly the US, demonstrate that good on-site management and appropriate regulation of all

[45] Public Health England, 2014, *Review of the Potential Public Health Impacts of Exposures to Chemical and Radioactive Pollutants as a Result of the Shale Gas Extraction Process*, A Kibble, T Cabianca, Z Daraktchieva, T Gooding, J Smithard, G Kowalczyk, N P McColl, M Singh, L Mitchem, P Lamb, S Vardoulakis and R Kamanyire.

aspects of the operations, from exploratory drilling to gas capture and well abandonment, as well as the use or storage of hydraulic fracturing fluid and the treatment of any wastes, are essential to minimise the risk to the environment and public health. PHE concludes that publicised problems in the US appear to be attributable to operational failures and inadequacies in the regulatory environment.

In 2016 the CSIRO completed a report for the New South Wales Environment Protection Authority into air emissions from gas development in New South Wales. From an air quality perspective, ambient emissions concentrations were low and, with certain exceptions, in the range expected for the particular source and the location or processes within that environment.[46]

In addition, a 2013 Queensland Department of Health risk assessment[47] concluded that, based on the clinical and environmental monitoring data available, a clear link can not be drawn between health complaints by some residents in the Tara region and impacts of the local CSG industry. The assessment found that the available evidence does not support claims that exposure to emissions from the CSG activities is the cause of the reported symptoms.

Emissions monitoring and reporting arrangements are detailed in the following section.

8.1.1. Air Quality monitoring in Queensland

The CSIRO and the Queensland government has established a comprehensive network fo air monitoring stations and has undertaken an assessment of air quality in the Surat Basin, focussed on the Chinchilla – Miles – Condamine area. This comprehensive study has used specialised instruments to measure, over two years, a wide range of pollutants in the atmosphere via a network of five ambient air quality stations. Importantly, the air quality data from the measurement network is streamed live to the Queensland Government website (http://www.ehp.qld.gov.au/air/data/search.php) to ensure transparency of data collection.

Analysis of the live data indicates that the air quality in the regions that host gasfield is of good quliaty. It shows that the air quality in gas field regions is assessed as 'good' to 'very good'. (The air quality in Hopelands is better than Brisbane). A report will be released via the GISERA website in late 2017 which will detail findings and methodology of the Air Quality Modelling study.

8.1.2. Particulate Matter. Reducing air pollution around the world

Particulate matter (PM) refers to everything in the air that is not a gas. Particulate matter, or PM, is the term for particles found in the air, including dust, dirt, soot, smoke, and liquid droplets. In Australia PM load naturally fluctuates due to airborne dust, sea salt, and smoke from bushfires. Motor vehicles and off-road engines such as generators, mining, earthmoving equipment and ships are the main sources of anthropogenic PM in Australia.

Particles less than 10 micrometers in diameter (1 thousandth of a millimetre) pose a health concern because they can be inhaled into and accumulate in the respiratory system.

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[46] Day, S., Tibbett, A., Sestak, S., Knight, C., Marvig, P., McGarry, S., Weir, S., White, S., Armand, S., van Holst, J., Fry, R., Dell'Amico, M., Halliburton, B., Azzi, M. (2016). *Methane and Volatile Organic Compound Emissions in New South Wales*. CSIRO, Australia.

[47] State of Queensland (Queensland Health), March, 2013, *Coal seam gas in the Tara region: Summary risk assessment of health complaints and environmental monitoring data*

Many major cities in the world have serious smog and air pollution problems from burning coal, oil and wood. Natural gas is a very safe and clean burning fuel that greatly reduces urban pollution. The use of natural gas results in very low emissions of nitrogen oxides and sulphur dioxide (reducing acid rain and smog) and has virtually no emissions of mercury, particulates (soot) or other solid waste.

This is one reason why natural gas is popular as an energy source. A former Chinese health minister, Chen Zhu, has estimated that 350,000 to 500,000 people die prematurely as a result of air pollution and air particulates in China each year (some have coined it 'Airpocalypse').[48] Natural gas is one of the key measures that can realistically reduce this. Chinese authorities have recently announced additional measures to increase the use of natural gas as a way of cutting their urban air pollution.

In 2015 and 2016 the International Gas Union released reports that contain case studies on the role of natural gas in improving air quality.[49][50] For instance, the 2016 report looks at the air quality benefits of the shift from coal to natural gas in Germany and how this shift contributed significantly to cleaning up Berlin's air in the decades after reunification.

In the 2015 Global Burden of Disease Study, also published in the Lancet, estimated that airborne particles (PM2.5) caused 4.2 million deaths and 103.1 million disability-adjusted life-years in 2015, representing 7·6% of total global deaths[51], making it the the fifth-ranking mortality risk factor.

[48] Moore, M. (2014), *China's 'airpocalypse' kills 350,000 to 500,000 each year*, The Telegraph, published 7 January 2014. www.telegraph.co.uk/news/worldnews/asia/china/10555816/Chinas-airpocalypse-kills-350000-to-500000-each-year.html
[49] IGU, (2016). *Improving air quality*, www.igu.org/sites/default/files/IGU_Urban_Air_Quality%20Report%202016_1711.pdf
[50] IGU, (2015). Improving air quality, www.igu.org/sites/default/files/IGU_Urban%20Air%20Quality%20FINAL%20for%20web%20etc.pdfhttp://www.igu.org/sites/default/files/IGU_Urban%20Air%20Quality%20FINAL%20for%20web%20etc.pdf
[51] Cohen, Aaron J et al. (2017), *Estimates and 25-year trends of the global burden of disease attributable to ambient air pollution: an analysis of data from the Global Burden of Diseases Study 2015*, thelancet.com/journals/lancet/article/PIIS0140-6736(17)30505-6/fulltext

8.2. Climate change

Climate change	There may be a risk that greenhouse gases, including hydrocarbons (methane and ethane) and carbon dioxide, will be released during hydraulic fracturing and the associated activities. Emissions may be from sources such as well heads, pipelines, compression stations and final use. The potential contribution of hydraulic fracturing and the associated activities to the burden of greenhouse gas emissions will be assessed by the Panel.

Greenhouse gas emissions from all stages of the production, supply and use of natural gas, including natural gas produced onshore, are reported by the Commonwealth's Department of the Environment and Energy (DOEE) in Australia's *National Greenhouse Accounts*.[52]

The measurement, estimation and reporting of emissions, including fugitive emissions, is required by the Commonwealth under the *National Greenhouse and Energy Reporting Act 2007* (NGER Act). The industry meets all its estimation, measurement and reporting obligations under the NGERs Act. Information collected under the NGERs Act is made available to all States and Territories. The NT has a unique emissions profile due to its large land mass, small population, high rate of bushfires, large cattle industry and the presence of emissions-intensive industries such as mining.

According to DOEE, the NT's emissions total in 2014 was approximately 12.6 Mt CO2-e; the energy sector accounted for half of this (6.3 Mt CO2-e) and agriculture around 23 per cent (2.9 Mt CO2-e).

According to the DOEE, fugitive emissions from the extraction of oil and natural gas around Australia have increased 2.9 million tonnes of carbon dioxide equivalent (Mt CO_2-e) since 1990 to 16.0 Mt CO2-e in 2015-2016. This includes methane emitted during production, in particular during drilling, testing, well completion, processing, venting and flaring.

To put this in context, since 1990 fugitive emissions from all sources of fossil fuel production[53] have increased by 14.4 per cent, reaching 40.76 Mt CO2-e in 2016. Fugitive emissions from the extraction of oil and natural gas across Australia was around 39 per cent of the total.

Across Australia, coal mining represents the largest source of fugitive emissions, at around 25 Mt CO2-e or 61 per cent of the total.

The emissions estimation methods used in the *National Greenhouse Accounts* are subject to external independent review each year by an Expert Review Team selected by the United Nations Framework Convention on Climate Change (UNFCCC).

NGERS provides a single national framework for emissions reporting by corporations. Corporations that meet the reporting thresholds must report their greenhouse gas emissions, energy production, energy consumption, and any other information specified under NGER legislation.

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[52] This data is available at www.environment.gov.au/climate-change/greenhouse-gas-measurement/tracking-emissions

[53] Fugitive emissions can occur during the production, processing, transport, storage, transmission and distribution of fossil fuels such as black coal, crude oil and natural gas. Emissions from decommissioned underground coal mines are also included in this sector. In the 2015-16 financial year, fugitive emissions accounted for 7.6 per cent of Australia's national inventory (2.3 per cent from oil and gas and 4.9 per cent from coal). See www.environment.gov.au/system/files/resources/48275b92-3f4b-44d0-aa4e-50ece408df86/files/nggi-quarterly-update-jun-2016.pdf for more.

The reporting thresholds are 25 kt of CO2-e emitted (or 100 TJs of energy consumed or produced) per year for facilities, or 50 kt of CO2-e emitted (or 200 TJs of energy consumed or produced) per year for corporations.

The NGER Determination provides methods and criteria for calculating emissions and energy data under the NGER Act. In addition, the *National Greenhouse and Energy Reporting (Measurement) Technical Guidelines* provide further information and calculation methods to assist with the application of the NGER Determination and the estimation of greenhouse gas emissions. Operators of facilities that meet reporting thresholds are required to report fugitive emissions from all stages of exploration, processing and production under the NGER Act and Regulations. Estimation methods must be consistent with the NGER Determination.

Emissions that occur during other stages of the supply and use of natural gas must also be reported under the NGER Determination if the relevant entities meet reporting thresholds. For example, suppliers may be required to report fugitive emissions due to leakage from pipelines, and large end-use customers are likely to meet thresholds for use of gas for heating or electricity generation.

Box 6: CSIRO Quantitative Study of Fugitive Emissions from CSG Wells

To provide quantitative information on emissions from CSG operations, CSIRO and the then Commonwealth Department of the Environment initiated a project to measure emissions from a range of production wells in Queensland and NSW[54].

Methane emissions were measured at 43 CSG wells – six in NSW and 37 in Queensland. Measurements were made by downwind traverses of well pads using a vehicle fitted with a methane analyser to determine total emissions from each pad. In addition, a series of measurements were made on each pad to locate sources and quantify emission rates.

Of the 43 wells examined, only three showed no emissions. These were two plugged and abandoned wells and one suspended well. The remainder had some level of emission but generally the emission rates were very low, especially when compared to the volume of gas produced from the wells. The principal methane emission sources were found to be:

- venting and operation of gas-powered pneumatic devices,
- equipment leaks and
- exhaust from gas-fuelled engines used to power water pumps.

Equipment leaks were found on 35 wells with emission rates ranging from less than 1 mg min^{-1} up to about 28 g min^{-1} . The median and mean emission rates from these wells were 0.02 g min^{-1} and 1.6 g min^{-1}, which correspond to emission factors of about 0.1 kg CO2-e t^{-1} and 2.4 kg CO2-e t^{-1}, respectively. This is consistent with the current emission factor of 1.2 kg CO2-e t^{-1} commonly used throughout the CSG industry to account for equipment leaks for the purposes of reporting emissions under the National Greenhouse and Energy Reporting legislation.

It is important to note that the field measurements found **no** evidence of leakage of methane around the outside of well casings at any of the wells.

This study's results are the first quantitative measurements of fugitive emissions from Australia's unconventional gas industry.

[54] Day, S., Dell'Amico, Fry, R., Javanmard Tousi, H., (2014). *Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities*. CSIRO, Australia

8.2.1. Fugitive Emissions

Both coal and natural gas are subject to fugitive emissions. Coal operations release gas during and after mining. Oil and gas industry fugitive emissions comprise the gas lost from production, processing, transport and distribution facilities, either from venting or from leaks in pipes, valves and other equipment. For the gas industry, reducing fugitive emissions produces two benefits: lower greenhouse gas emissions and increased volumes of energy. The less gas it loses, the more gas is available for sale. The industry has a strong market incentive to minimise fugitive emissions.

The Australian oil and gas industry measures and accounts for all its emissions, including any fugitive emissions associated with its activities. Fugitive emissions are managed carefully and are a small fraction of Australia's overall emissions. They do not change the fact that greater use of gas in Australia and overrseas is overwhelmingly positive for the Australian and global environment.

8.3. Amenity values

Amenity values	There may be a risk that there will be adverse impacts on amenity values such as national parks and rangelands due to gaseous emissions and flaring.

In Australia there are no established, measurable technical thresholds for significance of change for landscape and visual impacts. Companies consider visual amenity in detailed planning processes by considering the sensitivity of the landscape or visual receptor and the magnitude of change expected as a result of the development.

The sensitivity of a landscape is based on the extent to which it can accept change of a particular type and scale without adverse effects on its character. Sensitivity varies in the NT according to the type of development proposed and the nature of the landscape, including its inherent landscape value and the type of the proposed change. The magnitude of change affecting a landscape or visual receptor depends on the nature, scale and duration of the change.

Industry practices that address risks to the amenity values of national parks and rangelands have been addressed in Boxes 1, 3 & 4 above.

8.4. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

Potential risks associated with air quality and emissions should be considered with other industries and sources in order to provide an accurate understanding of the regional contribution. As noted above, the NT has a unique profile due to its large land mass, small population, high rate of bushfires, and large cattle industry. In Queensland for instance, studies into methane emissions being undertaken by the CSIRO in the gasfields around Dalby are finding cattle feedlots and other agricultural development is contributing significantly to air quality and emissions from the region. [55]

The industry is keen to work with government and other stakeholders to improve understanding of the industry's existing and potential impacts on air quality and emissions in the NT.

[55] GISERA Greenhouse gas and air quality https://gisera.org.au/research/greenhouse-gas-and-air-quality/

9. Public Health

The Industry takes the health and safety of its employees and local communities very seriously. The evidence shows that the industry is safe. Natural gas is commonly used in households all over Australia with no evidence that it is a health risk. Several major studies have found no link between oil and gas operations and health concerns.

9.1. Drilling and fracking chemicals

Drilling and fracking chemicals	There may be a risk that chemicals used during the drilling and hydraulic fracturing process are harmful to humans and livestock. Further, there may be a risk that those chemicals come into contact with humans or livestock via groundwater or atmospheric pathways. While the overall concentration of harmful chemicals in the water is low, the actual amount of chemicals can be significant and may pose a threat to the environment if not properly managed.

As noted in the 2014 Hawke Report to the NT Government[56]:

> *…chemicals used during hydraulic fracturing generally pose a low environmental risk, providing that leading practice is applied to minimising surface spills and managing flowback water after fracturing.*

The Background and Issues Paper identifies at Figure 6 that many of the chemicals used in fracturing fluids are found in processed food and a range of household products. These chemicals are routinely used in many other industries.

Risks to water quality and health risks associated with fracturing fluid chemicals may be minimised by strictly managed storage and handling (as per Material Safety Data Sheets), strict controls to ensure well integrity, and management of waste water after it is returned to the surface.

The 2014 Hawke Report[57] stated that the greatest environmental risk from drilling and fracturing chemicals appears to be surface contamination from spills or accidents during the transport and storage of large quantities of chemicals in their concentrated form before fracturing.

Best practice industry management includes:

- bunding the drill pad
- using spill mats below chemical storage sites and pipework and
- appropriate spill response and clean-up plans.

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[56] Hawke, A. (2014), *Report of the Independent Inquiry into Hydraulic Fracturing in the Northern Territory*, https://frackinginquiry.nt.gov.au/__data/assets/pdf_file/0008/387764/report-inquiry-into-hydraulic-fracturing-nt.pdf

[57] ibid

These chemical handling controls are common to many mining and other industrial processes, with well-developed regulation and guidelines, and the risks are not unique to unconventional gas extraction or hydraulic fracturing.

Evidence presented to the Panel by some opponents of the industry[58] claimed that chemicals used in the hydraulic fracturing process are secret and not publicly disclosed. This is not true. The NT Government has published chemical disclosure reports for a number of years. These are available at: https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/chemical-disclosure-reports. This is in addition to publishing a summary of Environment Management Plans (EMP's) approved by the DPIR. Summary EMP's are available at: https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/reports-for-petroleum-operational-activities. The *Petroleum (Environment) Regulations 2016* require public disclosure of EMP's and chemicals used.

9.2. Hydrocarbons and BTEX

Hydrocarbons and BTEX	There may be a risk that hydrocarbons associated with the extracted gas come into contact with humans or livestock via groundwater or atmospheric pathways. This may include aromatic hydrocarbons such as benzene, toluene, ethylbenzene and xylenes (**BTEX**), which have featured prominently in some risk assessments relating to petroleum and unconventional gas extraction, although BTEX is less likely to be a prominent feature of gas extracted from shale deposits. The use of BTEX in drilling and fracking fluids is prohibited in the Northern Territory.

As noted in the Background and Issues Paper, the use of BTEX in drilling and hydraulic fracturing fluids in the NT is prohibited. The Background and Issues Paper also notes that BTEX is not likely to be found naturally in significant quantities in shale gas reserves

Leusch and Bartkow (2010) state that the primary exposure to BTEX is from breathing air contaminated by motor vehicle emissions, industrial use and cigarette smoke[59].

The levels in drinking water are usually very low and intake from drinking and food sources is usually minor in comparison[60]. Groundwater in the vicinity of natural oil, gas and coal deposits may however contain elevated levels of naturally-occurring BTEX compounds. However, contamination from fuel spillage and industrial activities can result in localised high concentrations in surface and groundwater. In those instances, activated carbon filtration is an effective treatment option to reduce BTEX concentrations to acceptable levels.

Many of the industry operating practices outlined in Box 1 above address the risks associated with hydrocarbon and BTEX exposure. The industry works diligently to reduce the risks associated with development.

[58] For example: Frack Free Darwin, Merrilee Baker, Katherine Marchment, Arid Lands Environment Centre,
[59] Leusch and Bartkow (2010). *A short primer on benzene, toluene, ethylbenzene and xylenes (BTEX) in the environment and in hydraulic fracturing fluids*
[60] ibid

9.3. Radioactive substances

Radioactive substances	There may be a risk that radioactive materials from underground come into contact with humans or livestock as a result of the drilling or hydraulic fracturing process.

In some shales, the water may contain naturally occurring ions such as barium, strontium and bromine. In some cases the water may have low concentrations of naturally occurring radioactive materials (NORMS). Managing NORMs is a common issue for any industry that uses groundwater (such as agriculture) or any mineral development (such as quaries).

"Technically enhanced" naturally occurring radioactive materials (TENORM) refers to a potential accumulation or concentration of NORM from manmade processes. This includes oil and gas drilling, irrigation, water treatment, and any other process that may access groundwater or certain geology. There are well-established guidelines for dealing with NORM; and shale operators follow these industry standards.[61]

Shale rocks typically contain a range of different natural radioactive isotopes, such as uranium, lead, or potassium. NORM found in shale gas operations is usually below the common safety limits of radioactive exposure. When hydraulic fracturing fluid returns to the surface it may NORM. Shale gas developers have to ensure that NORM is managed appropriately. It is worth bearing in mind that even if a large number of wells were drilled in Australia, the amount of radioactive materials produced would be tiny compared to the amount produced by the medical sector and universities.

Movement of subsurface elements

The naturally present chemicals in rocks may be brought to the surface in produced water and needs to be carefully managed. Consultation has raised concerns relating to the movement of benzene, toluene, ethylbenzene, and xylenes (BTEX) naturally occurring in the ground.

Certain elements are naturally occurring in all groundwater – not just oil and gas. For instance, a study completed by the NT Government in 2008 (Karp, 2008) identified Humpty Doo, Darwin River Dam and Lake Bennett as areas whose overlying rocks could contribute arsenic to groundwater. A total of 96 samples were collected, with 88 in the areas where arsenic was suspected. Of the 88 samples, 15 contained arsenic over the Australian Drinking Water Guidelines. [62]

Light condensate, including naturally occurring hydrocarbon compounds may be associated with oil and gas and therefore present in recovered fluids. All flowback fluid is treated and managed. Separators are used to separate water, condensate, and gas for separate handling and the produced fluids are directed into lined pits (e.g. lined with UV stabilised HDPE or equivalent) or tanks before recycling, treatment or disposal.

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[61] Andrew W. Nelson, Andrew W. Knight, Dustin May, Eric S. Eitrheim, and Michael K. Schultz, *Naturally-Occurring Radioactive Materials (NORM) Associated with Unconventional Drilling for Shale Gas*, Hydraulic Fracturing: Environmental Issues. January 1, 2015 , 89-128 DOI:10.1021/bk-2015-1216.ch004

[62] T. Gough, R. Maeda (2012), *Water Quality Test Results from Top End Rural Area*. Northern Territory Department of Natural Resources, Environment The Arts and Sport, www.territorystories.nt.gov.au/bitstream/10070/251013/1/Water%20Quality%20Test%20Results%20from%20Top%20End%20Rural%20Area_FINAL.pdf

Management of NORM risks is common

The management of radioactive material is not unique to the oil and gas industry. The widespread occurrence of NORM means that sands, clays, soils and rocks, and many ores and minerals (e.g. coal, oil and gas, bauxite, phosphate rock, ores containing tin, tantalum, niobium, rare earths, and some copper and gold deposits), commodities (e.g. water, building materials, fertiliser), products (e.g. ceramics, glazes, uranium glass), by-products (e.g. phosphogypsum), residues with potential for future use (e.g. fly ash from coal burning, red mud from alumina production and slags from mineral processing), and devices used by humans (e.g. welding rods, gas mantles and electronic components) can contain NORM.

The Australian Governments Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) is the statutory body that regulates radiation in Australia. Detailed guides developed by ARPANSA outline the wide range of management controls in place to deal with these risks.[63]

For instance, farmers who use phosphate fertilisers (which contain NORM) take many of the same precautions as the oil and gas industry.

9.4. Mental health and wellbeing

Mental health and wellbeing	There may be a risk that the mental health and wellbeing of persons could be affected by an unconventional gas project. These factors could include increased costs of living associated with changing property values, access to social services, business failures, increased traffic, effects on the natural environment and concerns about the amenity of the local area.

The oil and gas industry recognises the importance of community wellbeing wherever it operates. APPEA members in the NT value their positive relationships with communities, recognising that a successful gas project rests on co-existence and community partnerships over decades.

One of APPEA's Principles of Conduct[64] is to support social and economic development in Australia in ways that:

1. Respect the rights, property and dignity of the communities in which we operate and acknowledge Aboriginal and Torres Strait Islanders as the first peoples of Australia.
2. Enable members to co-exist with stakeholders to generate long-term mutual benefit & enable member activities to foster economic growth and enduring value.
3. Provide Australian suppliers full and fair opportunity to compete for commercially competitive resource development activities.

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[63] Commonwealth of Australia, (2008), *Management of Naturally Occurring Radioactive Material (NORM)*, Australian Radiation Protection and Nuclear Safety Agency. www.arpansa.gov.au/pubs/rps/rps15.pdf
[64] See: www.appea.com.au/about-appea/principles-of-conduct/

APPEA members are committed to these principles.

To better understand wellbeing impacts, the CSIRO has identified a number of indicators that a community is adapting well to gas developments[65]. These are further detailed elsewhere in submission.

High community functioning

- good planning and leadership
- access to relevant information
- community is committed (can persevere, support its volunteers and gets involved)
- strong collective efficacy beliefs that the community can work together with government and industry to address problems and make the most of opportunities
- community trust is high
- people feel listened to and heard
- employment and business opportunities are good
- the environment is being managed well for the future

In a recent report on the Western Downs in Queensland, the CSIRO found that the largest change in wellbeing from 2014 to 2016 was the decrease in satisfaction relating to jobs and employment opportunities (associated with the change from construction phase to operations), and the largest improvements were in roads and the quality of the environment (e.g. dust and noise)[66]. The comparative results are shown in Figure 7 below.

[65] Walton, A., McCrea, R., and Leonard, R. (2016). *The 2016 CSIRO Community wellbeing and responding to change survey: Western Downs region, Queensland - Changes between 2014 and 2016 in the Context of Coal Seam Gas Development*. CSIRO report. CSIRO Australia
[66] ibid

Figure 7: Community wellbeing dimensions: 2014 and 2016[67]

The CSIRO report refered to above is a good example of the work produced by the Gas Industry Social and Environmental Research Alliance (GISERA). (GISERA) is a collaboration between CSIRO, Commonwealth and state governments and industry established to undertake publicly-reported independent research. At present, GISERA operates in Queensland and New South Wales.

The purpose of GISERA is to provide quality assured scientific research and information to communities living in gas development regions focusing on social and environmental topics including: groundwater and surface water, biodiversity, land management, the marine environment, and socio-economic impacts. The governance structure for GISERA is designed to provide for and protect research independence and transparency of research.

As part of the COAG Energy Council's Domestic Gas Strategy, the Australian Government is committed to supporting the establishment of GISERA in states and territories with existing or potential onshore gas industries.

APPEA and our members operating in the Northern Territory continue to support the establishment of an NT GISERA.

[67] In Figure 6, dimensions that were rated unfavourably are near the centre of the graph (1 out of 5) and those that rated favourably are near the perimeter (5 out of 5). The neutral point is 3 out of 5.

9.5. Diesel fumes

Diesel fumes	There may be a risk of emissions from plant and equipment, such as diesel fumes from drilling equipment and pumps and from off-site increases in road traffic.

More detail on air quality can be found in Section 8: Air.

Industry operating practices to reduce or eliminate risks associated with diesel fumes from drilling equipment and pumps and from off-site road traffic are identified are above. The combustion of diesel for generators and pumps is comparable with existing industries in the NT; including mining, agriculture and rural power generation. Industry reduces risks from diesel fumes by the selection of efficient and low pollution equipment; such as those fitted with diesel oxidation catalysts (DOC) and diesel particulate filters (DPF).

9.6. Physical safety

Physical safety	There may be a risk that physical safety may be compromised by factors associated with hydraulic fracturing including road transport accidents and seismic activity.

The oil and gas industry places a high priority on the safety of our workforce and the communities in which we operate. Detailed planning goes into the development of work programs and practices that place safety and health as key components. The risks to physical safety from seismic activity is considered to be very low in Australia, further information on seismic risks can be found section 3 of this document.

Road Transport

In a country as large as Australia, driving-related incidents is one of the largest risks for oil and gas company operations. The industry takes the road safety of all users very seriously. All companies operating land transport, or providing services involving land transportation, have in place a management system which includes those land transport operations and is based on a full assessment of the risks and measures to address such risks. The plans consider training, new road development, etc. All employees are required to undertake extensive driver assessment and training. The oil and gas industry in Australia spends millions of dollars investing in new road and upgrading existing infrastructure to reduce the risk to all road users.

One component of road safety is in-vehicle monitoring systems (IVMSIn-vehicle monitoring systems (IVMS), or driver behavior monitoring systems, refer to electronic devices that record data about a driver's behavior and vehicle use, such as date, time, speed, acceleration, deceleration, G-force and seat belt use. Data is sent back for real-time management. IVMS can also include fixed speed settings, whereby any vehicle speed exceeding would automatically trigger driving exception.

9.7. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

The development of a shale gas industry in the Northern Territory would not result in public health risks different from the development of any other industry. However, APPEA recognises that uncertainty can play a role in the level of stress and anxiety experienced in the community. Companies have committed to engage with the communities in which we operate in a genuine and consultative way so that all risks, perceived and real, are openly discussed and addressed. As such the industry is keen to work with the Government to understand and manage cumulitve impacts to public health from oil and gas industry development.

There are also positive cumulative outcomes from increased infrastructure and services in NT. For instance the availability of emergency medical services to local residents would be improved by the presence of a gas development. In southwest Queensland the provision of Lifeflight services has facilitated dozens of evacuations of injured people every year since 2011 – individuals and families have benefited in the most vital way possible through this service.

9.8. Select Public Health Studies

9.8.1. Monash University: Health Watch Study 14th report

- This ongoing university-based research program has been studying the health of 19,000 past and present Australian petroleum industry workers since 1980.
- The research clearly shows that petroleum industry employees have better health than the general Australian community and are less likely to die of the diseases commonly causing death - including cancer, heart and respiratory conditions.
- The 14th report can be found at: http://www.aip.com.au/health/ohs.htm

9.8.2. Queensland Government Department of Health: Coal seam gas in the Tara region - Summary risk assessment of health complaints and environmental monitoring data

This report by the Queensland Government presents the findings of their investigation into claims that gas development was harming residents in the Tara region.

Queensland Health found no clear link could be drawn between the health complaints of some residents and the the local CSG industry.

The Queensland Health report found that the nature of complaints meant there were multiple possible causes and explanations including faecal contamination in the water supply, the use of wood-fired heaters or open fires, and rainwater contaminated with bacteria, viruses or other organisms. These causes are not related to gas operations.

The report noted the most prevalent reported symptoms are headache, transient (reversible) eye irritation, nosebleeds and skin rashes. All of these are common medical complaints, as reflected by the following data:

- WHO (2012) reports an estimated 47 per cent of the adult population suffered a headache at least once within the last year and 1.7–4 per cent of the world's adult population have headache on 15 or more days every month.
- Various surveys of the prevalence of skin conditions in Australia have been reported (Marks, Plunkett, Merlin et al, 1999). These data show that the prevalence of self-reported skin disease, including eczema/dermatitis, is significant in the Australian community generally: The national health survey by the Australian Bureau of Statistics in 1989–90 found 12.7 per cent of the population reported a disease of the skin and subcutaneous tissue within the previous two weeks.
- In regard to nosebleeds, lifetime incidence in the general population is estimated at 60 per cent, though fewer than 10 per cent seek medical attention. Peaks in incidence occur in children under 10 years of age and adults older than 45 years of age (Medscape Reference, 2011; NICE, 2011).

9.8.3. Government of Western Australia Department of Health: Hydraulic fracturing for shale and tight gas in Western Australian drinking water supply areas

In 2015, the WA Department of Health undertook a 'human health risk assessment' of hydraulic fracturing to inform the WA Legislative Council's Environment and Public Affairs Committee's Inquiry into Hydraulic Fracturing for Unconventional Gas.

The assessment reviewed investigations into hydraulic fracturing and the potential impact on public health, including experiences in eastern Australia and overseas.

The Health Risk Assessment found that "under the right conditions, hydraulic fracturing of shale gas reserves in WA can be successfully undertaken without compromising drinking water sources."

This is primarily due to the depth of gas resources, the agreed industry/engineering standards, best practice regulation and appropriate site selection.

9.8.4. Public Health England review of health impacts of shale gas extraction

This review of scientific literature focused on potential impacts from all stages of shale gas extraction, including hydraulic fracturing.

It concluded risks to public health are low when operations are properly run and regulated.

Other findings included:

- potential risks and resulting problems reported in other countries were typically due to operational failure;
- good on-site management and appropriate regulation was essential to minimise environmental and health risks;
- proper well construction and maintenance was essential to reduce the risks of ground water contamination; and
- hydraulic fracturing was unlikely to contaminate groundwater because of the depth at which it occurs.

10. Aboriginal People and their Culture

Shale gas exploration companies working with Traditional Owners in the NT have made it a priority to engage with Aboriginal communities. As the projects move from exploration to commercial development, Traditional Owners will emerge as key beneficiaries of the onshore petroleum industry.

We aim to build enduring relationships with the Aboriginal communities within which we operate. APPEA members have a strong commitment to respecting culture and development of communities. Companies develop comprehensive cultural heritage management systems to support compliance with legislation and agreements with traditional owners.

The development of the onshore gas industry brings significant opportunities to aboriginal people, including employment, training, education and enterprise opportunity associated with our industry.

APPEA aims to assist oil and gas operators and Aboriginal communities by working with the land councils in the development and provision of information about the industry's activities and environmental impacts. Information workshops about onshore oil and gas have been and continue to be delivered.

APPEA is also seeking to ensure that approvals processes for gaining access to land operate in a transparent and efficient manner to the benefit of all parties, including indigenous communities. We view engagement with local indigenous communities as a broad, inclusive and continuous process of interaction between that spans the entire life of the project.

10.1. Land ownership

Land ownership	There may be a risk that hydraulic fracturing or the associated activities will disrupt traditional practices that connect Aboriginal landowning groups with their country and underpin recognition of their ownership of that land.

The oil and gas industry respects the connection Aboriginal people have to their country and the importance placed on the landscape, terrestorial ecosystems, flora and fauna that are central to these values.

Aboriginal peoples in the Northern Territory are the traditional custodians of land and through various legislated provisions the beneficial landowners of some 50% of the NT. For the oil and gas industry they are a key stakeholder.

The recognition of Aboriginal legal rights at a general level, and the explicit recognition of ethnographically identified, land-connected Aboriginal groups on the lands and waters on which extractive companies seek to operate, is a central tenet for working in the NT. Beyond requirements of the *Aboriginal Land Rights (Northern Territory) Act 1976* (Cth) (ALRA), the *Native Title Act 1993* (Cth) (NTA) and at common law, for reasons of self-interest, it also makes complete sense for extractive businesses to forge local level agreements with relevant custodial Traditional Owners.

Industry practices that address risks to connection to country have been addressed in Box 2 above.

10.2. Benefits

Benefits	There may be a risk that the development of the industry will occur without short and long term benefits flowing to local Aboriginal communities.

Developing the Northern Territory's onshore natural gas resources promises to create significant employment and training opportunities and new income streams for Aboriginal Territorians.

In a video released as part of the NT onshore gas industry's communications campaign, Indigenous Construction Resource Group director Russell Jeffrey highlights the industry's importance in providing more opportunities for the socio-economic development of Aboriginal Territorians and their communities.

"*If an industry can come in – and it's regulated, it's safe and it's creating jobs, it's creating opportunities – I think the pride in those communities will actually grow, along with the work*," Mr Jeffrey says in the video, available at: https://vimeo.com/174169715.

Projects such as the Mereenie oil and gas fields west of Alice Springs, now operated by Central Petroleum, and exploration preparations for companies including Origin Energy, Pangaea Resources and Santos have provided Traditional Owners with training and work opportunities on country.

Case Study: Intract Indigenous Contractors at Mereenie

In 2013, Intract Indigenous Contractors won an earthworks contract with Santos' Mereenie drilling and appraisal program. The contract included the construction of lease pads for the drill rigs, new buildings and accommodation camp and about 40 kilometres of roads. The work provided training and employment for members of the local community that will assist them in gaining further work in the industry.
"It's great to work out here on my land, and a lot of my nephews and that, they can see what I'm doing and it might encourage them to do the same. I've learnt a lot of stuff here and I'd like to see more young men like me doing the same.[68]*"*

The oil and gas industry is committed to ensuring opportunities for Aboriginal training and employment are maximised as the industry grows from short-term exploration work through to multi-decade operations.

The resources sector is the largest private sector employer of Indigenous people in Australia, and where an Indigenous business is embedded in a resources project the percentage of Indigenous employment increases dramatically. The broader mining and energy resources industry has a higher proportion of indigenous employees than any other Australian industry, and that stands to increase if the continued development of the Territory's natural gas resources is able to proceed.

Case Study: Pangea Indigenous Employment Training Pilot Program

In 2015, Pangaea developed a close partnership between local contractors and the Northern Land Council (NLC) to develop a program to identify and train a group of cadets with the special cultural knowledge and support of the traditional owners of the land. The Program has been designed to ensure that young people have the opportunity to work 'on their country' while having the support network of family during placement.

The NLC helped Pangaea consult with senior Elders and spokespersons from each of the three family groups (Liwaja, Wubalawun and Jalalabayin people) on whose country Pangea's 2015 exploration campaign was being conducted. The meetings introduced the Program opportunity, but most importantly, engaged with 'Mentors' from each family group who could assist in selecting the most appropriate candidates from their extended families to take advantage of the training and employment opportunity.

The model of linking 'country to candidates' is essential for success. The over-riding sense of responsibility for country - and each other - in a family group was critical to ensuring completion rates and enthusiasm. In the future it also means that the land has been respected and its value preserved for future traditional owners.

The Pangaea drilling project creatied jobs which are needed to ensure that training opportunities lead to the social, cultural and economic benefits that communities need.

The Pangaea Project has been a great boost and potentially holds great opportunity for traditional Aboriginal owners to employ their knowledge in managing their own country in the future.

[68] Anslem Impu Jnr, *Gas and oil expansion generates work for traditional owners*, ABC 7.30 NT Report, www.abc.net.au/news/2013-06-21/gas-and-oil-expansion-generates-work-for/4773150

10.3. Culture, values and traditions

Culture, values and traditions	There may be a risk that the above and/or below ground disturbance associated with drilling and hydraulic fracturing or as the result of seismic activity caused by hydraulic fracturing or reinjection of water will have an adverse impact on Aboriginal culture, values and the traditions that connect landowning groups with their country and sustain community cohesion.

The oil and gas industry respects the cultural values of Aboriginal people and the importance placed on the landscape, terrestorial ecosystems, flora and fuana that are central to these values.

In addition to legislated requirements, detailed, comprehensive and transparent agreement-making with Aboriginal Traditional Owners can include specific provisions for how cultural values and practices are protected. Industry practices that manage risks to cultural heritage and connection to country have been addressed in the Box above.

10.4. Community wellbeing

Community wellbeing	The development of the unconventional gas industry may have an adverse impact on the wellbeing of Aboriginal communities.

The oil and gas industry understands the need to engage respectfully and thoroughly with Aboriginal communities on whose lands we seek to operate. Informed consent is critical to ensure a mutual beneficially partnership that not only delivers positive economic outcomes but also protects the environment and cultural heritage. We refer the Panel to APPEA's comments above in relation to Community Wellbeing in general and agreement making processes for accessing Aborignal land as being relevant to the Panel's consideration of Aboriginal community wellbeing.

10.5. Aquatic and terrestrial ecosystems

Aquatic and terrestrial ecosystems	The development of the unconventional gas industry may have an adverse impact on aquatic and terrestrial ecosystems important to Aboriginal culture.

Industry has in place a number of mitigation measures and practices designed to minimise and/or eliminate risks of activities impacting on aquatic and terrestrial ecosystems.

For water quality and quantity, these are been outlined in Box 1 above. Industry practices that manage risks to cultural heritage and connection to country have been addressed in Box 2 above. In addition, Box 3 above outlines a number of industry practices designed to minimise and/or eliminate risks on terrestrial ecosystems and biodiversity.

10.6. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

Social impact assessments that consider the broad scope of all developments in an area are run to ensure all risks are comprehensively considered. The industry is keen to work with traditional owners and the Government to understand and manage cumulative impacts.

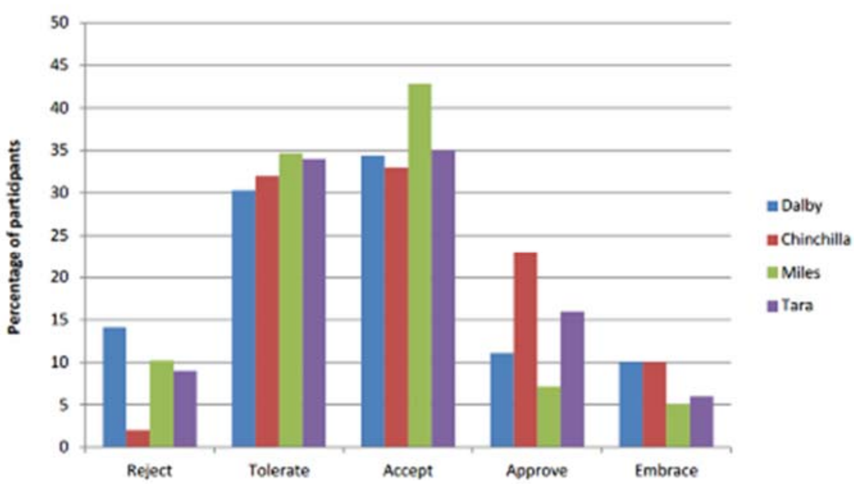
11. Social

Many reputable and independent studies have identified significant positive regional socio-economic benefits of onshore gas and resources production. Community attitudes to the industry have also been found to be positive.

This research confirms that the resources industry is most supported in areas where it operates

- The Australian Government's Bureau of Resource and Energy Economics (BREE) reported in 2015 that there are long term net economic benefits from CSG and negligible impacts of water and air quality to date.
- The CSIRO reported in 2013 that the CSG industry is contributing to poverty reduction, increasing employment and family income, and that there is a growing youth population in regions with CSG development.
- A 2013 study by KPMG showed that resources developments are not only making regions more prosperous, but also making their communities more stable and socially sustainable.
- A 2014 report by the CSIRO found that the majority of the community in Tara, Chinchilla, Miles, and Dalby accept, approve, or embraces the industry with only a small minority rejecting the industry:

Attitude towards CSG



Source: CSIRO survey of community wellbeing and responding to change: Western Downs region in Queensland, September 2014

11.1. Housing and rents

Housing and rents	There may be impacts on local housing, which may decrease or increase rents and house prices as a result of an increased population.

The low level of unconventional shale gas activity in the NT means that there is little to no research or significant data points to quantify industry impacts on housing.

The onshore gas industry has had an impact on rents and housing. These have been both negative and positive. As noted by the GasFields Commission Queensland[69], some rural property listings underline the benefits of the value of compensation paid by the CSG industry to specific properties or the economic opportunity that comes from being located in proximity to the gas industry.

Companies take steps to house the workforce in temporary accommodation and ensure housing was secured for locals. In some areas the construction phase has resulted in a surplus of housing which has impacted investors and locals alike. The industry needs to work closely with regulators, local government and the local community to collaboratively address housing to ensure supply and demand can be more closely matched.

Assessing the impacts in rural areas has been difficult. In 2014 the Queensland GasFields Commission met with representatives of the rural valuation industry to discuss current property value trends and how to obtin more consistency in valuing the impacts of CSG activity on rural properties for compensation purposes. The meeting included the Queensland Valuer-General and representatives from major Queensland rural valuation firms. The 'overwhelming view' was that:

> *"…given the prolonged drought and lack of property sales with gas infrastructure, there was still insufficient evidence of a trend in rural property values as a result of the onshore gas industry."*

The Queensland Valuer-General's Property Market Movement Reports over 2014, 2015 and 2016 note that in rural areas there is limited sales activity and land values are linked to agricultural market factors, including for example:

- the effects of a long-term and widespread drought;
- restrictive financial policies;
- the weakening Australian dollar;
- the strengthening beef market; and
- agricultural commodity values.

In some regional urban centres the mining and gas sector does influence property values, with the impact being generally positive when the sector is expanding and generally negative during slowdown periods (as is the case for any economic activity).

APPEA is not aware of any reports of banks negatively reviewing farms due to the presence of CSG.

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[69] GasFields Commission Queensland, (2014), *Rural valuers share insights on gas impacts*, 1 April 2014, www.gasfieldscommissionqld.org.au/whats-happening/rural-valuers-share-insights-on-gas-impacts.html

Queensland Valuer-General: Property Market Movement Report 2016

This report summarises the comprehensive analysis of all property markets within the 2016 annual valuation program for Queensland by a team of regionally based registered valuers in the State Valuation Service of the Queensland Department of Natural Resources and Mines.

Key findings include:

- As the gas industry in the Surat Basin moves from exploration and development into the production phase, property markets in the Basin have slowed. Workforce numbers dropped from their construction-phase peak in most communities affected by the slowing of the resource industry sector.
- Across Queensland, limited sales activity in many rural markets—including grazing, broadacre farming, sugar cane and horticulture— resulted in static land values. The exception was increased land values in the grazing and broadacre farming markets of Central Queensland and the Darling Downs.
- Any increase in land values was influenced by the strengthening of beef commodity prices. The grazing and broadscale farming markets are starting to rise from the bottom of the market cycle. The Eastern Young Cattle Index reached a record high at $600.75c/kg in January 2016, compared with $439.25c/kg at the same time in 2015.
- Sales of rural land purchased by resource companies for the purpose of mining or other extractive industry are not used to determine statutory land values of rural land. This market activity has now slowed due to the state of resource sector, and respective markets are now being influenced by rural landowners.

Queensland Valuer-General: Property Market Movement Report 2015

This report summarises the comprehensive analysis of all property markets within the 2015 annual valuation program for Queensland by a team of regionally based registered valuers in the State Valuation Service of the Queensland Department of Natural Resources and Mines.

Key findings include:

- The mining and gas industries continue to influence the property market as the resources sector moves from an exploration and construction phase towards a production and export phase. This slowdown in activity is impacting on centres such as Gladstone, Wandoan, Mackay, and townships within the Bowen Basin and Central Highlands. Limited sales activity in rural markets across Queensland resulted in a continued staticto- softening of land values in grazing, horticulture, small cropping and dryland farming. Rural industries are dealing with the effects of a longterm and widespread drought, restrictive financial policies and rising costs.
- Across Queensland there is limited sales activity in rural markets, resulting in a continued static to softening of land values within the grazing, horticultural, small crop and dryland farming industries. All industries are dealing with the effects of a long-term and widespread drought, restrictive financial policies and rising costs. In contrast, the effects of the recent weakening of the Australian dollar and the strengthening of beef commodity prices may not be reflected in the marketplace for some time.
- The grazing market is at the bottom of its market cycle and has probably stabilised. These trends, where potential purchasers still remain cautious, will continue for some time until there is an improvement in the weather and more confidence in the economy.

Queensland Valuer-General: Property Market Movement Report 2014

This report summarises the comprehensive analysis of all property markets within the 2014 annual valuation program for Queensland by a team ofregionally based registered valuers in the State Valuation Service of the Queensland Department of Natural Resources and Mines.

Key findings include:

- The mining and gas industries continue to influence the property market as the resources sector is moving from an investment phase towards an export phase. This slowdown in activity in infrastructure construction is impacting on Gladstone which is showing evidence of a subdued residential market after years of high growth. Continuing activity in the Surat Basin is still driving development activity and land values in a number of centres including Miles.
- Generally, across Queensland there has been limited sales activity in rural markets resulting in a continued softening of land values within the grazing, horticultural, small crop and dry land farming industries. The combined and ongoing effects of the continuing drought, global financial crisis, changes in bank lending policies, the persistent high Australian dollar, the overseas livestock trade ban, lower commodity prices and rising costs have made potential purchasers cautious.

The construction peak of a large mining or infrastructure project can put pressures on housing affordability and rent, due to the need to accommodate a large temporary workforce. Although this problem should be minimised by the provision of temporary accommodation by project proponents, workers in other sectors boosted by the development (such as hospitality) need housing, and increased demand will push up prices.

Such rises create difficulties for renters in the community who do not benefit from increased wages in the resources sector, which can range from dishwashers and hotel cleaners to teachers, police officers, and state government staff.

Increases in population, combined with increases in income and consumption, can have a large impact on housing affordability, particularly during the peak of the construction period. Both rents and house prices increased in the Western Downs towns during the construction phase. In 2013, housing rents in Miles were roughly $200 higher than the Queensland median, and median house prices peaked around 2013.[70] This University of Queensland study also found that the size of the town made a large difference to the scale of the impact, with smaller towns experiencing much higher pressures on affordability than larger towns, as the size of the non-resident workforce accommodated and working nearby was much greater in proportion to the population of the town centre.

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[70] Witt K, Uhlmann V, May K, Johnson S and Rifkin W (2014) *Interim Data Reports: Possible indicators of impact of CSG development on Chinchilla, Dalby and Miles and district communities, Cumulative Socioeconomic Impacts of CSG Development in the Western Downs Project*, Centre for Social Responsibility in Mining, University of Queensland, Centre for Coal Seam Gas, Brisbane

This pressure is less likely to continue, as worker accommodation villages are being located closer to gas fields rather than in town centres.[71] As at June 2014, around 95 per cent of non-resident workers are housed in these villages rather than other forms of accommodation, including hotels and caravan parks.[72]

Across Queensland's Western Downs, rents and prices have now dropped significantly, with some residents noting that housing is now returning to 'affordable' levels, with some concerns that rental vacancies are now too low.[73]

Resolving the pressure on housing is clearly a matter of balance when a temporary workforce is involved. Communities will be keen to maximise the benefits that can accrue from resident workers rather than non-resident workers. This shift, though, will increase pressure on the existing stock of housing and require new residences to be built. However, once the workforce peaks and employment opportunities are reduced, excess housing supply can also cause problems, as noted by local real estate agents.[74]

11.2. Insurance

Insurance	There may be a risk that there will be an increase in insurance costs and liabilities of landowners, occupiers, and traditional owners.

A common provision in Land Access Agreements with landowners, occupiers and traditional owners is for the petroleum operator to, at its own cost, hold appropriate insurance to industry standards and as required by law in respect of its activities. Such insurances include, but are not limited to:

- an appropriate level of public liability insurance for any one event relating in any way to the land or the petroleum activities or the operator's use of the land; and
- worker's compensation insurance.

Given that the petroleum operator bears the risks and liabilities of impacts of its activities, it is difficult to see circumstances where insurance providers could justify increasing the premiums and liabilities of policies covering landowners, occupiers and traditional owners. This would essentially amount to double dipping by insurance providers.

APPEA is not aware of any direct evidence that landowner's insurance premiums have increased as a direct result of hosting oil and gas activities. In this regard insurance costs can be closely monitored and where detriment is identified, compensatory measures can be implemented.

[71] Queensland Government Statistician's Office (2014a) *Surat Basin Population Report 2014*, Queensland Government, Brisbane
[72] ibid
[73] Witt (2014)
[74] ibid

11.3. Health services

Health services	There may be impacts on the local health system (hospitals, health services etc) as a result of an increased population, including that there may be increased health services in remote communities as a result of industry's presence.

The onshore petroleum industry has a proud record of investing in rural, regional and remote health services.

For example, the Queensland CSG industry has invested in partnerships to improve existing health service delivery and issupporting introduce new programs to improve access to services. A number of case studies are highlighted below.

Case Study: QGC/Shell

QGC/Shell is a leading domestic producer of natural gas and operator of the QCLNG export project. Like all major project proponents QGC proactively invests in social and community infrastructure in order to provide a lasting legacy for the community and offset any impact it may have on existing infrastructure.

An example is QGC's investment in health services. QGC has implemented several initiatives aimed at improving health service delivery as detailed below.

Virtual services—Health-e-Regions

Telehealth is the umbrella term for the electronic and telecommunication-based expansion of health care services. Telehealth adds a new paradigm in healthcare, where the patient is monitored between clinic visits.

Telehealth has been shown to significantly reduce hospitalisations and visits to the emergency departments, while improving patients' quality of life. Telehealth also benefits patients where traditional delivery of health services is affected by distance and lack of local specialist clinicians. Time and cost to access health facilities often constitute a major obstacle to seeking care and can be a burden on the financial stability of a household.

In partnership with the University of Queensland's Centre for Online Health, we established the Health-e-Regions program, a comprehensive network of telehealth services in Dalby, Chinchilla and Miles that provides online and video links between patients and specialists in Toowoomba and Brisbane. In 2015, the program was extended to include Tara and Wandoan.

Between 2013 and 2014, 5935 telehealth consultations were reported through the Darling Downs region, compared with 2912 in the year before the project began. According to the University of Queensland Centre for Online Health's Deputy Director, Associate Professor Anthony Smith: "*We've had an overwhelmingly positive response from patients who have started using the Health-e-Regions telehealth service*." The project has reduced the travel cost for families who previously had to travel significant distances to see a specialist in a major city.

Mobile services

Mobile outreach services enable greater utilisation of specialist competencies to serve remote communities. These services increase the effectiveness of frontline health workers and counsellors and respond directly to patient concerns. Often, outreach services trigger specialist follow-up visits, ultimately reducing inequity in access to care.

QGC funded Lifeline Darling Downs South West Queensland to support three mobile counsellors in the Western Downs Counselling Project, including a financial counsellor, to provide face-to- face counselling and outreach services to people in and around Dalby, Chinchilla, Wandoan, Miles and Tara. From February 2012 to December 2014, Lifeline Darling Downs South West Queensland counsellors supported 813 clients during 5199 sessions. They have also delivered 23 group sessions in these regions. Counsellors were extensively accessed during the floods of 2012 in the Chinchilla community. The mobile counsellors reached many who may not otherwise have had access to counselling.

QGC provided $1.2 million for the Tara Community Outreach Medical Service to provide mobile medical and dental service for families in the Tara Rural Residential Estates and broader region. Delivered by Murri Health Group, a not-for-profit Indigenous owned entity, the aim of the program was to increase the availability of preventative and primary health care. Since September 2013, the service has delivered 593 dental appointments and 563 general medical assessments and treatments. Murri Health Group will be able to continue to provide health services on a sustainable basis, as they are funded through Medicare.

The QCLNG project area covers many remote locations where access by road is difficult and which require aerial transport in medical emergencies and during natural disasters. QGC works in partnership with other Queensland LNG proponents (Arrow Energy, APLNG, and Santos GLNG) to fund the Surat Gas Aero- Medical Service. Launched in 2011, this service has undertaken retrieval missions of community members and CSG workers, provided flood assistance and responded to emergency distress beacons. In addition to our Surat Basin medical evacuation helicopter, Curtis Island Rotary Wing Aeromedical Evacuation Service was launched in 2013 for the Gladstone region. Both services are managed by CareFlight Group Queensland. The joint $35 million funding commitment has provided a dedicated response to medical emergencies and natural disasters across Central and Southern Queensland.

Combined, the aeromedical services conducted 496 retrievals over July 2012 to February 2014 of which 160 were for members of the public who needed urgent medical attention and would not have otherwise had a rotary service available to rapidly respond.

Physical health infrastructure

QGC invested $3.5 million in Gladstone Hospital to establish a renal dialysis unit and refurbish the peri-operative suite. As an outcome of the investment, patients can receive improved treatment in Gladstone, thus reducing the need to travel to Rockhampton or Brisbane for dialysis.

The investment included $2 million for a renal dialysis centre, which included three renal dialysis units, patient chairs and a supporting reverse osmosis facility, refurbishment of the facility, staff training, and the cost of operating the centre for two years. Since the start of operations, the renal dialysis centre delivered 3508 treatments.

The remaining $1.5 million was invested in the refurbishment of the hospital's 35-year-old peri-operative suite. Refurbishment commenced in April 2015 and, once complete, the suite will provide an improved environment for patients, relatives and staff and help in attracting priority services and specialist staff to Gladstone.

It will also complement the planned upgrade of the hospital's high dependency unit by allowing more patients to have operations at the hospital and then be cared for in the unit. Gladstone Hospital Executive Director Dr Nicki Murdock said; "*We are extremely grateful to our industry partners for these generous contributions that will improve the hospital for both patients and staff … Up to 3000 patients are expected to use the new facilities each year and it will be wonderful for our dedicated and professional staff to have a modern, purpose-built workplace which will help them provide even better care to our patients*."

Support and infrastructure for health professionals

QGC identified the need to sustain or increase the capacity of staff in Indigenous community services to deliver rural health solutions. In partnership with Goondir Health Services, QGC invested $166,350 into the Goondir Health Staff and Board Member Training Program.

The training package focused on increasing clinical and governance capacity to provide rural health services with training targeted to up-skill staff in the following six key areas:

- primary health care training for 11 staff
- service plan training for all staff and the Board
- health promotion training for 20 staff
- quality improvement training for 20 staff
- human resource management training for 1 staff member
- governance training for 10 staff and executive.

As a short-term support measure during peak construction period, QGC provided lowcost housing to health workers in order to improve access to health services. QGC provided, at minimal rent, two, four bedroom houses to the Darling Downs Hospital and Health Service to house a senior dentist and Director of Nursing in Miles. QGC also supported the provision of 30 nursing bursaries through the University of Southern Queensland to encourage student nurses to undertake clinical placements in rural and regional hospitals away from family and support services.

Case Study: Arrow Energy regional specialist care

Cardiovascular disease is the largest cause of death in Australians (2011 Census) and current research shows that cases of the disease are over 15 per cent higher in remote and regional areas.

The Heart of Australia program is a partnership between local Brisbane Cardiologist Dr Rolf Gomes and Arrow Energy to deliver Australia's first mobile specialist cardiac service to patients living in rural and remote Queensland. The state of the art clinic, towed by a Kenworth prime mover, has two consulting rooms, new ultrasound, electrocardiogram and cardiac stress testing equipment.

It can instantly share test results with other GPs and hospitals and allow other specialists to dial-in through state-of-the-art telemedicine capabilities.

Since the program's launch in October 2014, the service has delivered:

- 355 specialist clinics in 11 towns across regional Queensland
- Provided care to more than 1600 patients
- Referred 573 urgent cases identified with eight being referred for open heart surgery
- An average of 841kms travel saved per patient
- 216 avoidable hospital admissions/reduced length of stay

Companies operating in the NT are committed to working with the NTG and host communities to both understand the extent of (temporary and/or permanent) population growth in communities and what this means for key public services such as health services.

11.4. Education

Education	There may be an impact on the local education system as a result of an increased population.

Evidence in regions hosting CSG activity in Queensland indicates that development has led to higher youth education levels. There is evidence in CSG areas of education levels higher at younger ages than the broader population, including completion of secondary school, university degrees and advanced technical training.[75] These changes in education and gender patterns were part of a broader positive impact of CSG activity on areas subject to rural decline.

The BREE report notes that migration contributes to this lift in mean levels of education. At the same time, the opportunity for skilled work in the local region can encourage young people into relevant trades training or other education.

The gas industry regularly invests in school-based traineeships and apprenticeships. In addition education programs are implemented in areas where we operate. For instance the Queensland LNG companies invested in a CSG Industry schools program that aimed to raise the profile and interest in science, mathematics, engineering and technology in 35 state schools and six independent schools throughout the Surat Basin from Dalby to Roma and surrounding communities.[76]

Companies operating in the NT are committed to working with the NTG and host communities to both understand the extent of (temporary and/or permanent) population growth in communities and what this means for key public services such as education services.

11.5. Infrastructure

Infrastructure	There may be an impact on infrastructure, such as roads, as a result of increased traffic.

Onshore gas activity involves truck and vehicle movements associated with transporting workers and equipment, which can lead to concerns regarding road safety and degradation of infrastructure. It is worth noting that existing infrastructure in remote parts of the NT is often underused. Where necessary, proponents seek to improve shared local infrastructure such as road and telecommunication infrastructure[77]. For some coexisting industries, improved road infrastructure can open up year round access to markets, providing additional revenue opportunities. It is important to note that the gas industry in Queensland invests millions of dollars in improving road infrastructure. This continues to be a massive benefit to regional areas.

[75] Commonwealth of Australia (2015) *Review of the socioeconomic impacts of coal seam gas in Queensland*, Office of the Chief Economist, Department of Industry, Innovation and Science.
[76] See: www.santosglng.com/media/pdf3140/130731_schools_program_media_release.pdf
[77] Walton, A., McCrea, R., & Leonard, R. (2014). *CSIRO survey of community wellbeing and responding to change: Western Downs region in Queensland*. CSIRO Technical report: CSIRO, Australia.

11.6. Livelihoods

Livelihoods	There may be an impact on peoples' livelihoods.

The CSIRO reported in 2013 that the Queensland onshore gas industry is contributing to poverty reduction, increasing employment and family income[78].

An analysis of census data by Fleming and Measham found that income inequality (measured by the Gini coefficient) has increased on average *less* in resource regions than non-resource regions between 2001 and 2011[79]. The study showed that income inequality increased by an average of 8.7 per cent in non-resource regions, but only around 4.8 per cent in resource regions. Growth in inequality in Queensland's Bowen and Surat Basins, for example, was even smaller, 1.3 per cent and 3.3 per cent respectively.

11.7. Long-term benefits

Long term benefits	There may be a risk that the development of the industry will occur without short and long term benefits flowing to the local community.

With a successful development scenario in the NT being spread over multiple decades, benefits will flow according to short and long term project schedules. The Australian Government's Office of the Chief Economist reported in 2015 that there are long term net economic benefits from onshore gas development in Queensland[80].

11.8. Community cohesion

Community cohesion	There may be an impact on community cohesion and resilience, particularly in relation to fly-in, fly-out workers.

The oil and gas industry has a long history of using a mix of employment strategies that change based on the phase of acvitity from exploration, development and ongoing operations. This includes a mix of residential employees and contractors, fly-in / fly-out (FIFO) and drive-in / drive out (DIDO) workforces.

Short-term changes as a result to swings in numbers from FIFO workers is closely managed. Over the long term companies have committed to provide opportunities for local and regional residents. Gas companies also seek to settle new interstate workers in local towns.

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[78] Measham T. and Fleming D. (2013) *Impacts of unconventional gas development on rural community decline: working paper*, November 2013, CSIRO, Australia.
[79] Fleming D. and Measham T. (2013) *Disentangling the Natural Resources Curse: National and Regional Socioeconomic Impacts of Resource Windfalls*, https://publications.csiro.au/rpr/download?pid=csiro:EP139781&dsid=DS2
[80] Commonwealth of Australia (2015) *Review of the socioeconomic impacts of coal seam gas in Queensland*, Office of the Chief Economist, Department of Industry, Innovation and Science.

APPEA does not anticipate the construction of new LNG facilities to support a development in the NT. Australia's existing export capacity in the NT and Queensland and current supply-demand forecasts suggest that there will be substantial demand for gas in the east coast. This would eliminate the influx of workers seen in other States required for large-scale construction. In addition, pipeline capacity is limited and growth would be limited.

Project proponents have committed to working with host and supporting communities to manage expecations and impacts.

11.9. Crime

Crime	There may be an increase in crime.

A CSIRO report on wellbeing in Queensland's Western Downs region found that community spirit was one of the most positively perceived aspects of wellbeing[81]. Survey respondents reported that they felt that they could rely on others in the community to help, they could work together, and that relationships within the community were friendly.

The oil and gas industry has a zero-tolerance approach to serious crime in its workforce. However, crime impacts have been experienced in regions that have experienced population growth from onshore gas development.

This is in line with population growth. For instance, there has been an increase in reported offences in the Western Downs region, primarily good order (nuisance) and traffic offences. [82] Local police have noted that traffic impacts are the largest concern and that it has primarily been 'locals' involved, not CSG workers.[83]

Actions have been taken to mitigate the increase in offenses, including changing police strategies, community responses, such as implementing a local liquor accord, and company responses, such as computerised vehicle monitoring[84].

[81] Walton, A., McCrea, R., & Leonard, R. (2014). *CSIRO survey of community wellbeing and responding to change: Western Downs region in Queensland*. CSIRO Technical report: CSIRO, Australia.
[82] ibid
[83] Rifkin, W. (2016), *Indicators of change in Roma and district community*, Cumulative socioeconomic impacts of CSG Development in Queensland Research Project, University of Queensland, Sustainable Minerals Institute boomtown-indicators.org/sites/report.boomtown-toolkit.org/files/roma_booklet_v12_celoxis_0.pdf
[84] Rifkin W, Witt K, Everingham JA and Uhlmann V (2015) *Cumulative Socioeconomic Impacts of CSG Development in the Western Downs, Preliminary Draft Report*, Sustainable Minerals Institute Centre for Social Responsibility in Mining, University of Queensland Centre of Coal Seam Gas, Brisbane

11.10. Employment

Employment	They may be an impact on local employment and skill levels.

The level of employement and local benefit is variable depending on the scope and scale of future projects. However, the development of the gas industry has been a significant benefit to local employement in other onshore gas developments. According to a comprehenive survey undertaken by the Queensland Resources Council, the Queensland gas industry supports more than 40,000 direct and indirect employees in 2015-16, representing 1.7% of the State's employement.[85] More than $8.8 Billion was spent in external businesses generating significant employement and economic multipliers.

The CSIRO reported in 2013 that Queensland's onshore gas industry is contributing to poverty reduction, increasing employment and family income, and that there is a growing youth population in regions with CSG development[86]. The same CSIRO report found that in host communities, secondary school completion rates were higher and local populations had higher levels of vocational and tertiary qualifications than regions without an onshore gas industry present.

The development of the gas industry brings significant benefits to employement and skills. These opportunities include:

- Opportunity to increase labour-force participation and increase local skills capacity
- Opportunities for apprenticeships, scholarships and vocational training

Opportunity to support work readiness programs and pre-trade training conceptsProject proponents have committed to working with host and supporting communities to manage expecations and impacts.

11.11. Business

Business	There may be an impact on local business opportunities.

The development of a new industry brings significant opportunities to local businesses. The industry generates regional and local buy sourcing goods and services locally. As noted above more than $8.8 Billion was spent in external businesses in Queesland alone in 2015-16.

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[85] Queensland Resources Council, (2016), *Economic Impact of the Minerals and Energy Sector on the Queensland Economy 2015/16*, www.qrc.org.au/wp-content/uploads/2016/10/FinalReport_compressed.pdf
[86] Measham T. and Fleming D. (2013) *Impacts of unconventional gas development on rural community decline: working paper*, November 2013, CSIRO, Australia.

Local business opportunities is linked to both the phase of industry activity and local skills and capability. APPEA's Principles of Conduct commit members to providing Australian suppliers full and fair opportunity to compete for commercially competitive resource development activities.

A recent communique by the CSIRO forecast oscillating periods of local business activity in Queensland's onshore gas industry and identified a number of implications for local SME's[87]. These include:

- Look after core customers
- Stay connected
- Understand the industry
- Seek business advice early
- Keep a close eye on business figures and beware of possible risks
- Be careful not to overcapitalise
- Be diversified in what you do
- Seek out reliable information
- Personal considerations (impact on work/life balance)
- Opportunities to learn and grow and build resilience.

We welcome working with the local business community to build capacity for local businesses.

11.12. Amenity

Amenity	There may be a risk that the amenity of persons living on the land will be adversely impacted by hydraulic fracturing and its associated activities.

As detailed in previous sections, operators work closely with landowners to position infrastructure and activity away from residential and recreational amenities

11.13. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

Experience shows that the benefits to regional areas from developing a new gas industry is not without it's challenges but is overwhelmingly a positive one. Regional areas that have developed their gas resources have resulted in lower unemployment rates, better infrastructure, skills and economic growth. By working closely with governments and the community the cumulative opportunities from development can be better understood.

[87] Measham, T. and Walton, A. (2016), *Looking to the Future: Job forecasts for the Surat Basin 2014 to 2034*. CSIRO Communique: CSIRO, Australia.

12. Economic

A report for APPEA on economic benefits from the development of an onshore gas industry in the NT by leading economists at Deloitte Access Economics found by 2040, the NT's Gross State Product (GSP) would be between $5.1b and $7.5b higher, in real terms, than if no development had occurred. This represents an increase of between 26 percent and 37 per cent on current estimates for the NT ($19.9 billion in 2012-13). In net present value (NPV) terms (2015 dollars), over the entire period to 2040, the cumulative increase in GSP is expected to be between $17.2b and $22.4b.

Under the scenarios modelled, the development of the sector is projected to add between $236m and $460m per annum, above the base case, to NT Government revenues by 2040.

To put these figures into perspective, the projected revenue for the NT Government from taxation royalties in 2016-17 is $132 million. A permanent increase in annual revenue of between $236 million to $460 million marks a step change in the financial resources available to the Territory to provide infrastructure and services to all NT citizens.

12.1. Distribution

Distribution	There may be a risk that any economic benefits will not be shared by the regions that are directly affected by the industry, and/or will not be shared equitably between the gas companies, the government, and the community.

Communties hosting or supporting onshore gas activity in the NT are already benefiting from the use of local suppliers and employment opportunities. For example, APPEA members Central Petroleum and Pangea Resources highlighted the engagement of local businesses and employees in thier evidence to the Panel on 6 and 10 March 2017 respectively[88].

Should an unconventional gas industry be developed in the NT, further opportunities for local business, employment and government revenue will be realised.

As noted above, Deloitte Access Economics found that, in a range of development scenarios, between $236m and $460m per annum will be added to NT Government revenues. The NT Government will decide where and when to spend any additional revenue streams it receives.

In addition, over the period 2020-2040, the NPV of additional capital expenditure is estimated at $10.1b under Deloitte's 'Success' scenario, with a peak annual estimate of $3.3b invested in 2027. Under the Aspirational scenario the NPV of capital investment is estimated at $13.9b, with a peak of $4.8b in 2030.

In terms of ongoing operational expenditure over the life of projects, Deloitte projected this to stabilise under the 'Success' and 'Aspirational' scenarios at $0.9b and $1.4b p.a. respectively. It is this ongoing spend in the NT that will grow and sustain local businesses, and regional and indigenous communities.

[88] See: www.frackinginquiry.nt.gov.au/submission-library/?a=414045 and www.frackinginquiry.nt.gov.au/submission-library/?a=410613

And finally, the Deloitte report found that employment in the NT is also expected to rise significantly with the development of an unconventional gas industry by between 4,200 Full Time Equivalents (FTEs) to reach 6,300.

12.2. Property values

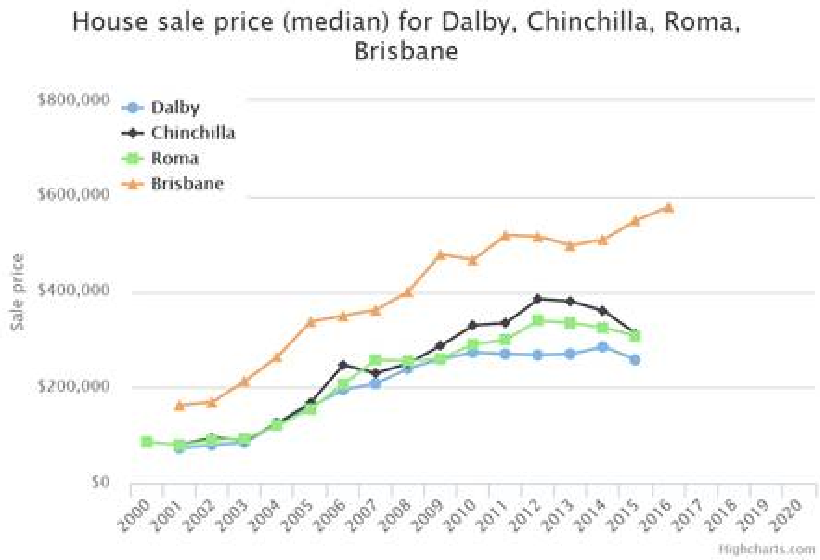
Property values	There may be a risk that there will be a decrease or increase in existing property values.

The challenges of economic growth are preferable to the challenges of economic decline. Gas developments can often cause a spike in local property values due to the additional jobs and general economic activity these projects bring. Please refer to section 11 for more discussion on housing and rents.

In Queensland's Surat Basin, house prices and rents increased while there was a jobs and investment boom. As the initial construction phase has now been completed house prices and rents have eased but remain higher than levels seen before construction. The industry will continue to make a very significant contribution to regional economies for decades to come. Everyone in the Surat now benefits from a diversified economy, more jobs, and more business opportunities.

In the Surat Basin in Queensland property values and rents ave increased while there was a jobs and investment boom. As the initial construction phase has now been completed house prices and rents have eased but remain higher than levels seen before construction.

A range of data on changes to the Surat Basin economy over time have been collated and published by the University of Queensland and is available at https://boomtown-indicators.org. Trends in house prices are shown below.



12.3. Other industries

Other industries	There may be a risk that there will be an adverse impact on other businesses, such as tourism, fishing, agricultural and pastoral businesses.

As an industry that plans to co-exist with other industries for decades, it is in the interests of the onshore gas industry to create and maintain positive relationships with these industries. The increased availability of unconventional gas and the associated development of pipeline infrastructure could:

- increase the use of gas by new industrial projects in Darwin and regional centres,
- improve the economics of supplying gas for power generation to remote communities and mining projects across the NT,
- encourage a switch away from other fossil fuels to gas, and
- encourage investment in new energy intensive processing industries like petrochemicals.

12.4. Energy security

Energy security	There may be a risk that energy security in the Territory will be jeopardised if the gas is undeveloped.

Developing unconventional gas for the domestic market wouldunderpin future energy security, enable the supply of additional gas into the NT market and diversify the Territories gas supply security. Gas exploration and discoveries add to the resource base available to provide gas for the domestic market. Exploring for onshore gas provides greater potential supply diversity than relying entirely on offshore developments.

12.5. Net impacts

Net impacts	There may be a risk that any economic benefits will not outweigh economic detriments.

The Deloitte report referenced above concluded that "*Development of shale and tight gas resources in the NT have the potential to significantly bolster the region's economic growth*"[89].

Deloitte used its in-house CGE model to determine if shocks to the NT economcy of various unconventional gas development scenarios would lead to net positive or net negative economic impacts compared to a base case of no unconventional gas development.

As noted above, across economic metrics such as GSP, employment, and Government revenue, development of unconventional gas results in significant net positive benefits to the NT economy.

APPEA is not aware of any genuine analysis which shows that developing the onshore gas industry will involve significant economic costs.

[89] Deloitte Access Economics (2015), *Economic impact of shale and tight gas development in the NT*, https://www.appea.com.au/wp-content/uploads/2015/08/APPEA_Deloitte-NT_Unconv_gas_FINAL-140715.pdf.

12.6. Management

Management	There may be a risk that, if not properly managed, any economic benefits will result in 'boom and bust' economic activity.

Project proponents will work closely with relevant Government agencies and local communities to manage development expectations, opportunities and challenges. As an industry that expects to operate for decades in the NT, it is in the interests of the industry to seek sustainable economic outcomes and smooth out investments over time.

12.7. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

In a scenario where multiple projects are developed, it is very likely that the cumulative economic benefits are greater than indicated above.

13. Land Access

In Australia, the Crown owns the mineral resources and the NT Government is responsible for allocating permits to explore and licences to produce. Before petroleum companies seek access to properties to explore for Crown resources in onshore areas, they carry out extensive consultation with landholders and farmers. Companies bid for development rights and when producing, pay royalties and other taxes to governments which are used to improve the wealth of the local communities, the Territory and the nation.

The Australian Government's Multiple Land Use Framework (MLUF) is an established position between the Australian and State/Territory governments on co-existence and is supported by APPEA. The MLUF states that:

> *"rights of all land users and the potential of all regulated land uses should be acknowledged and respected, while ensuring that regulated land is not restricted to a sole use without considering the implications or consequences for other potential land uses, and the broader benefits to all Australians."*

APPEA strongly supports policies that foster coexistence. The approach of working together to establish a framework that supports ongoing development in both the agriculture and resources sectors, and of education and mutual understanding of the needs of all parties, has proven successful and continues to be the most effective way to manage land access in Australia.

Experience shows that petroleum companies have been able to successfully negotiate thousands of land access agreements and compensation arrangements with farmers. Over 5,100 landholder access agreements have been successfully negotiated in Queensland alone. Demonstrating that land access can be, and is being successfully managed. In Queensland the gas industry is also delivering infrastructure and investment to several rural and regional districts, providing new jobs and strengthening and diversifying regional economies.

APPEA is working nationally with peak farming and pastoral industry bodies and directly with regional communities to address some of the concerns about development of natural gas production on private land, including in relation to water management and farmers' and pastoralists' rights.

The petroleum sector recognises that good communication and trust-building underpins successful coexistence. On this basis, APPEA is working with companies and the NT Cattleman's Association (NTCA) to establish a shared understanding of how science and cooperation can help in resolving technical issues and concerns about petroleum exploration activities.

The key concerns raised by NT pastoralists include:

- Long-term well integrity and risk to water aquifers;
- Biosecurity and chemicals management;
- Land access, compensation arrangements and pastoralists rights; and
- Uncertainty about the scale, nature and timing of future industry activity.

APPEA and the NTCA worked with the then NT DME to develop a land access process where petroleum companies and landholders will be required to reach a land access agreement before exploration activities are approved and can begin. Notification and consultation requirements must also be followed as petroleum titles are being assessed and granted. This process has been endorsed by APPEA and the Northern Territory Cattlemen's Association.

Other ways of providing information to, and engaging with, NT pastoralists are also being pursued such as APPEA's continued sponsorship and provision of an information booth at the NTCA Annual Conferences and industry information booths provided at a number of NT regional and metropolitan shows.

13.1. Consultation

Consultation	There may be a risk that gas companies do not consult adequately with land owners, occupiers, or traditional owners, in gaining access to the land for exploration and extraction purposes.

APPEA promotes a strategic and coordinated approach to engagement and consultation to provide a framework for productive and positive long-term relationships with stakeholders.

Genuine engagement with stakeholders is essential for promoting and achieving sustainable development. Effective consultation and communication processes must inform and educate the stakeholders to address issues in a timely manner.

The degree of consultation will depend on the nature and scale of any planned activity and the nature of the communities involved. Clear consultation and communication for a planned activity may further reduce impacts, improve research focus and produce better outcomes.

In 2005 APPEA, and other industry associations, supported the development of the "Principles for Community Engagement" by the Government's Ministerial Council on Mineral and Petroleum

Resources.[90] While individual jurisdictions and industries have unique approaches to consultation, the principles (and the corresponding elements under each) provide a sound basis for good practice for use by industry. The principles are:

1. COMMUNICATION
   Open and effective engagement involves both listening and talking
   a. Two-way communication
   b. Clear, accurate and relevant information
   c. Timeliness
2. TRANSPARENCY
   Clear and agreed information and feedback processes
   a. Transparency
   b. Reporting
3. COLLABORATION
   Working cooperatively to seek mutually beneficial outcomes
4. INCLUSIVENESS
   Recognise, understand and involve communities and stakeholders early and throughout the process
5. INTEGRITY
   Conduct engagement in a manner that fosters mutual respect and trust A description of the elements of these principles is included in detail on the subsequent pages

13.2. Consent

Consent	There may be a risk that gas companies enter the land without, where required, obtaining the consent of the landowner, occupier, or traditional owners, causing conflict.

The industry complies with its legal obligations and will not enter land without the required approvals.

APPEA strongly supports policies that foster coexistence, and mutual benefit. There is ample evidence showing that regional businesses, agriculture and the gas industry can and do co-exist in Australia through responsible cooperation and a spirit of goodwill.

The natural gas industry operates according to industry best practice and the relevant regulations in place.

In Queensland, for example, permit holders require the consent of the landowner – in the form of a conduct and compensation agreement - for all activities other than defined 'preliminary activities' which have no or minimal impact on the land use or business of the landowner. In the case of

[90] MCMPR Principles for Community Engagement. http://www.sacome.org.au/images/MCMPR_Principles_for_Community_Engagement.pdf

preliminary activities, a permit holder must give written notice at least 10 days in advance to advise of its intention to enter the property. The notice explains to the landowner the location and timing of the visit and the details of any activities to be carried out. The activities of the permit holder are governed by Queensland's Land Access Code. Access to restricted areas around buildings and other structures requires the written consent of the landowner.

Resource Ownership

Previous Government inquiries have found that providing an absolute right for landholders to veto land access would introduce what is essentially "*akin to a private ownership scheme for certain resources. Large amounts of compensation that private landholders may secure as a result of this would reduce the wider public benefit that arises from state ownership of the resources.*"[91]

There is no benefit to the community if the State maintains ownership of the resource (for the benefit of all) but is unable to ensure its development. Fundamentally, this is an issue of first principles. When the State owns the resource, the right to ensure its development rests with the State.

Furthermore, the right to veto raises significant questions for future use of land for various purposes - including other activities undertaken by the private sector which may have public benefits. For example, if a similar veto was passed in relation to the development of linear infrastructure (roads, rail, power lines, pipelines and irrigation infrastructure), a single landholder could effectively prevent projects and development that are necessary for the nation. It would be difficult to argue why some industries which create a public benefit should be singled out by government, and others which also require access to land to create a public benefit should not be.

Confidentiality clauses

The inquiry has head claims that the industry binds landholders in confidentiality clauses. APPEA members have all agreed that, upon request from a landholder or farmer party to a confidentiality agreement, they will release them from any obligations for confidentiality. It is not the gas companies who are enforcing confidentiality. Landholders do not generally like the idea of their business affairs made public.

13.3. Conditions

Conditions	There may be a risk that gas companies and landowners, occupiers, and traditional owners, do not negotiate mutually beneficial conditions associated with any agreement permitting access.

Landholders around Australia have signed thousands of land access agreements with gas comapnise. We recognise negotiating agreements can be a daunting experience for landholders but communicating early and often helps the parties reach mutually beneficial arrangements.

In 2016 APPEA undertook a sentiment survey across landholders engaged with the gas industry. The survey found that the vast majority of landholders were satisfied with their agreement and the

[91] Commonwealth of Australia, (2015), *Report: Landholders' Rights to Refuse (Gas and Coal) Bill 2015*, Senate Standing Committees on Environment and Communications, , Ch. 4, www.aph.gov.au/Parliamentary_Business/Committees/Senate/Environment_and_Communications/Gas_and_Coal/Report/c04

main reasons for this satisfaction was *'good and fair compensation'*, and *'fair and mutual outcomes'*.

As such APPEA is confident mutually-beneficial relationships between landowners, occupiers and traditional owners can be reached.

13.4. Compensation

Compensation	There may be a risk that compensation paid for access and/or disturbance to land will not be adequate. There may be a risk that if there is an incident in the exploration, extraction or production of any gas, the land may not be properly remediated or the land owners, occupiers, or traditional owners may not be adequately compensated.

Landholders are fairy compensated for their time working with the natural gas industry. The industry's obligation to compensate landowners creates a strong, mutual incentive to negotiate access in ways which minimise impacts on the landowner's business.

APPEA looks forward to working with the NT Government to develop an assessment and government compensation framework for land access.

In other jurisdictions compensation payments are calculated based on the disturbance experienced by the landholder. This varies depending on the type of activity and the type of property. This creates an equitable payment that considers the specific disturbance experienced by the landholder (wells, access tracks, etc) and how the land is used (vacant scrub land, irrigation, etc). Landholders with comparable impact will receive equitable payments.

13.5. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

Companies are required to undertake cumulative scenarios in approvals to ensure all risks are considered.

14. Regulatory Framework

Effective regulation is critical to building community confidence and trust as it ensures that activities are assessed and approved to standards that mitigate risk and minimise environmental impacts. If investment is to be encouraged and maximised, regulation must also be efficient in terms of avoiding duplication while delivering certainty and transparency.

The gas industry is committed to working with the Northern Territory Government in updating and adapting onshore regulatory regimes to changes in the industry. Government also needs to ensure that its reform processes and the outcomes it seeks to deliver are well understood by the community, particularly those with an interest in the land accessed by petroleum explorers and producers.

APPEA notes the information on the regulatory framework outlined on page 12 of the Panel's *Background and Issues Paper*. Industry research has identified many other acts, agreements and guidelines that are relevant to such activities are shown overleaf.

NT Legislation
Petroleum Act 2016 **and associated Regulations and Schedule of Requirements** - Regulates petroleum exploration and production, including environmental protection measures to be used during exploration and production activities, including protection of parks and reserves and rehabilitation
Northern Territory Aboriginal Sacred Sites Act 2012 **and associated Regulations** - Provides for the protection of sacred sites, through establishing procedures for entering such sites and procedures for avoidance of such sites when developing and using land - Generally refers to land other than Aboriginal land
Heritage Act 2011 **and associated Regulations 2012** - Serves to protect archaeological sites
Soil Conservation and Land Utilisation Act 2009 - Provides for the prevention of soil erosion and for the conservation and reclamation of soil
Environmental Assessment Act 1994 **and associated Regulations** - Provides for the assessment of the environmental effects of development proposals and for the protection of the environment - Defines environment as being "all aspects of the surroundings of man including the physical, biological, economic, cultural and social aspects"
Public and Environment Health Act 2011 - This Act provides a framework for regulations to be prescribed for all public health matters
Bushfires Act 2009 - Outlines regulations and established penalties for certain acts relating to lighting fires
Territory Parks and Wildlife Conservation Act 2011 **and associated Regulations** - Provides for the protection, conservation and sustainable utilisation of wildlife
Waste Management and Pollution Control Act 2011 - Protects and where practicable restores and enhances the quality of the NT environment. It encourages ecologically sustainable development and facilitates implementation of National Environment Protection Measures
Work Health and Safety (National Uniform Legislation) Act 2011 - provides for a balanced and nationally consistent framework to secure the health and safety of workers and workplaces
Water Act 2011, as amended 2013 - Provides for the investigation, allocation, use, control, protection, management and administration of water resources, including extraction of groundwater, waste management and water pollution
Weeds Management Act 2001, as amended 2013 - Identifies declared weeds (those which must be controlled) and provides a framework for weed management
Dangerous Goods Act 2012 - Provides for the safe storage, handling and transport of certain dangerous goods
Commonwealth Legislation
Aboriginal and Torres Strait Islander Heritage Protection Act 1984 - Provides for the preservation and protection of places, areas and objects of particular significance to Aboriginal people
Environment Protection and Biodiversity Conservation Act 1999 - Provides for the protection of the environment and conservation of biodiversity, particularly species and places of national significance - Invoked only if a development is likely to have environmental impacts of national significance

Aboriginal Land Rights (Northern Territory) Act 1976 - Provides for the granting of Traditional Aboriginal Land in the Northern Territory for the benefit of Aboriginals, and for other purposes
Native Title Act 1993 - Provides for the recognition and protection of native title for Indigenous peoples
Agreements
Native Title Agreements - Details the environmental and cultural protection measures to be included in the EP
Exploration Permits - Details the environmental protection measures to be included in the EP
Guidelines
AS 1940: The storage and handling of flammable and combustible liquids, 2004 - Provides guidance for the operation and handling of flammable and combustible liquids
Codes of Practice of the Australian Petroleum Producing Exploration Association - Provides guidance for environmental management during petroleum exploration and production activities
Environmental Health Program Directorate Code of Practice for Small On-site Sewage and Sullage Treatment Systems and the Disposal or Reuse of Sewage Effluent, 2014 - Provides guidance of the management of effluent in this context - It is noted that Territory Health Services will issue any amendments to the above Code on an annual basis
ISO 19011: Guidelines for quality and/or environmental management systems auditing, 2002 - Provides guidance on environmental auditing to a certifiable standard
The Northern Territory Dangerous Goods Regulations and Australian Standard 1985 (as amended 2014) - Provides regulation and guidance on appropriate storage requirements for on-site fuel tanks
Northern Territory Pastoral Land Clearing Guidelines (NT Pastoral Land Board, 2010) - Although clearing for roads or tracks is a significant cause of erosion on pastoral leases, there is no requirement to obtain formal approval from the Pastoral Land Board. Instead, clearing must be carried out in accordance with Land Clearing Guidelines (NRETAS, 2010)
Land Clearing Guidelines (NRETAS, 2010) - Provides technical advice for planning and undertaking land clearing in a manner that will avoid/minimise adverse environmental impact - Provides guidance for clearing along linear developments, such as roads, tracks, fence lines, pipelines and exploration lines - Outlines the circumstances under which approval for clearing must be sought
Integrated Natural Resource Management Plan for NT (NT Government, 2011) - Describes the current condition, use and threats, and provides possible management solutions for the Territory's natural resources and environments - Includes guidance for improved management of pastoral land, through control of weeds, responsible clearing, prevention of overstocking and reduction in wildfire occurrence.
Best Practice Erosion and Sediment Control (International Erosion Control Association, 2008) - Facilitates the identification of those issues that should be considered when formulating and evaluating strategies for best practice erosion and sediment control - Facilitates best practice stormwater management - Facilitates active avoidance or minimisation of soil erosion resulting construction activities - Facilitate best practice soil and sediment control management on sites.

The key reference for regulators in Australia should be the Australian Government's 2015 Domestic Gas Strategy and the Standing Council on Energy and Resources (SCER) endorsed National Harmonised Regulatory Framework for Natural Gas from Coal Seams (the Framework).

APPEA supports the Framework. Although it was primarily developed for coal seam gas, it can be readily adapted to unconventional gas more broadly. Adoption of the Framework does not necessarily require developing new legislation, as many of its elements are already in place.

The Framework provides a suite of leading practice principles and provides guidance to regulators. The Framework covers the key areas of operation (and risk), including well integrity, water management and monitoring, hydraulic fracturing and chemical use. The Framework is not in itself a risk assessment of the industry but has developed a set of leading practices which are framed in a way that is compatible with a risk-based approach to regulation.

The Framework recommends that regulatory and legislative settings should be underpinned by the principle of co-existence. This is where a shared commitment exists between the resources industry, other land users, local communities and governments to multiple, merit-based and sequential land use that provides certainty for industry and improved community confidence in land use decision-making.

The Framework identifies 18 leading practices to mitigate the potential impacts associated with the development of natural gas from coal seams and builds a robust national regulatory regime for the industry. These are summarised in Table ES.1 in the Framework which is copied below.

Table ES.1: Summary of leading practices

	Leading practice	Well integrity	Water management	Hydraulic fracturing	Chemical use
1	Undertake a comprehensive environmental impact assessment, including rigorous chemical, health and safety and water risk assessments	✔	✔	✔	✔
2	Develop and implement comprehensive environmental management plans or strategies which demonstrate that environmental impacts and risks will be as low as reasonably practicable	✔	✔	✔	✔
3	Apply a hierarchy of risk control measures to all aspects of the project	✔	✔	✔	✔
4	Verify key system elements, including well design, water management and hydraulic fracturing processes, by a suitably qualified person	✔	✔	✔	✔
5	Apply strong governance, robust safety practices and high design, construction, operation, maintenance and decommissioning standards for well development	✔	✓	✓	✓
6	Require independent supervision of well construction	✔			
7	Ensure the provision and installation of blowout preventers informed by a risk assessment	✔			
8	Use baseline and on-going monitoring for all vulnerable water resources		✔		
9	Manage cumulative impacts on water through regional-scale assessments		✔		
10	Ensure co-produced water volumes are accounted for and managed		✔		
11	Maximise the recycling of produced water for beneficial use, including managed aquifer recharge and virtual reinjection		✔		
12	Require a geological assessment as part of well development and hydraulic fracturing planning processes	✓	✓	✔	
13	Require process monitoring and quality control during hydraulic fracturing activity			✔	✓
14	Handle, manage, store and transport chemicals in accordance with Australian legislation, codes and standards			✓	✔
15	Minimise chemical use and use environmentally benign alternatives			✓	✔
16	Minimise the time between cessation of hydraulic fracturing and flow back, and maximise the rate of recovery of fracturing fluids			✓	✔
17	Increase transparency in chemical assessment processes and require full disclosure of chemicals by the operator in the production of natural gas from coals seams			✓	✔
18	Undertake assessments of the combined effects of chemical mixtures, in line with Australian legislation and internationally accepted testing methodologies			✓	✔

Key:
✔ Leading practice primarily applies to this core area and is discussed within its respective chapter
✓ Leading practice is also relevant to this core area

14.1. Failure to protect the environment

Failure to protect the environment	There may be a risk the regulatory framework does not adequately protect the environment (water, land, and air) from risks associated with hydraulic fracturing and associated activities.

The promolgation of new Petroleum Environment Regulations in mid-2016 introduced an element of best practice environment regulation to the NT. The new regulations address gaps in the regulatory framework that had been identified by independent experts Dr Alan Hawke and Dr Tina Hunter. The new regulations improve transparency and enforcement and enhance public confidence in onshore gas activities.

The regulations have a strong focus on objective-based environment outcomes from activities associated with onshore gas. The regulations require detailed environmental management plans (EMP) based on risk assessments, to be submitted before any exploration or development activity. EMP's are reviewed by the DPIR (as Regulator), in addition to the Environment Protection Authority (EPA). Before any activity can be undertaken the Regulator must ensure that environmental impacts and risks associated with the activity are reduced to a level that is as low as reasonably practical (ALARP) and acceptable.

There are also additional powers under the *Environmental Assessment Act 1994 (NT)*. At the Commonwealth level the EPBC Act can be triggered where a petroleum activity has the potential to have a significant impact on a matter of national environmental significance.

The NT Government also took a Territory wide environment reform policy into the 2016 election. APPEA looks forward to working with the NTG to ensure its regulatory regime is fit-for-purpose for petroleum activities and best practice. As noted in earlier sections, industry supports the removal of the exemption of petroleum activities from the Water Act.

14.2. Land access

Land access	There may be a risk the regulatory framework does not appropriately balance the rights of landowners, occupiers, and traditional owners with those of gas companies.

Coexisting industries and traditional owners have and continue to engage regularly and meaningfully to understand the opportunities and challenges that come with an unconventional gas industry. APPEA and the NTCA worked with the then NT DME to develop a land access process where petroleum companies and landholders will be required to reach a land access agreement before exploration activities are approved and can begin. Notification and consultation requirements must also be followed as petroleum titles are being assessed and granted. This process has been endorsed by APPEA and the NTCA.

Other ways of providing information to, and engaging with, NT pastoralists are also being pursued such as APPEA's continued sponsorship and provision of an information booth at the NTCA Annual Conferences and industry information booths provided at a number of NT regional and metropolitan shows.

As noted in earlier sections, APPEA does not support a right of veto for landowners for onshore gas activity. Governments are the custodians of public good resources, including land and underground minerals and resources. It is appropriate that government determines how public good resources can be accessed through an open and transparent process that ensures that potential developers (above and below ground) have the necessary skills and capability to develop those resources in a responsible manner.

14.3. Public health

Public health	There may be a risk the regulatory framework does not adequately mitigate public health risks associated with the unconventional shale gas industry.

As noted in earlier sections, industry has numerous operating practices in place that prevent the potential for hazardous materials to enter the environment. These practices are continuously improving based on local and international experience and best practice. It is important, therefore, that regulations are objective based, rather than prescriptive, to allow for this continuous improvement.

There is also the opportunity for improved access to public health infrastructure and services from the development of an unconventional gas industry, particularly in remote and rural areas. Examples are provided in section 11.3 above.

14.4. Aboriginal culture and communities

Aboriginal culture and communities	There may be a risk the regulatory framework does not adequately protect Aboriginal culture, values, traditions and communities from risks associated with the unconventional shale gas industry.

As noted in section 10 above, industry takes serious its relationships with Aboriginal people and our responsibilities to protect their culture, values and traiditions. We work closely with traditional owners under common law and relevant legislative processes prior to the commencement of any exploration and development activity.

Box 2 above provides a number of examples of industry practices relevant to this section.

14.5. Social impacts

Social impacts	There may be a risk the regulatory framework does not adequately mitigate the social risks associated with the unconventional shale gas industry.

Evidence presented in section 11 addresses in detail social impacts. It is important that social impact assessments undertaken are appropriate for the nature and scale of proposed activity and initiate the necessary actions as part of existing approval processes.

14.6. Economic impacts

Economic impacts	There may be a risk the regulatory framework does not ensure that any economic benefits are appropriately distributed between the gas companies, the government and the community.

As noted above in section 12, independent analysis of a number of onshore gas development scenarios shows that significant ecomomic benefits will flow to the NT economy.

APPEA believes that the existing regulatory framework strikes the appropriate balance to ensure that economic benefits flow to gas resource owners (NT citizens), gas developers and host communities (landowners and Aboriginal communities).

APPEA looks forward to engaging with the independent consultant to be appointed by the Panel to confirm these benefits.

14.7. Compliance and enforcement

Compliance and enforcement	There may be a risk of inadequate monitoring or enforcement of compliance with the regulatory framework. This may arise from, for example, inadequate resourcing of the regulatory agency or inadequate training of relevant officers. There may be a risk that sanctions provided for in the regulatory framework are inadequate or are not utilised by the regulator. There may be a risk that the cost of complying with the regulatory framework is too high for industry and the industry becomes uneconomic.

While resourcing matters are a matter for the NTG, APPEA believes that agencies must be appropriately resourced, to ensure that sufficient skilled staff are available to review what can be complex and technical data and reports, and assess compliance.

It is also vital that processes across government agencies and regulators are streamlined and coordinated to avoid regulatory duplication and ensure that roles and responsibilities are well understood to avoid any regulatory gaps.

14.8. Complexity

Complexity	There may be a risk that the regulatory framework is needlessly complex.

APPEA considers that governments at all levels should aim to establish regulatory frameworks based on the following principles:

- Clear objectives and transparent oversight:
  - The rationale for any regulation must be well defined and understood and a net benefit clearly identified. Government regulation may not always be the most effective policy solution or mechanism to manage risk.
  - The processes for implementing regulation must be transparent, clear, uniform and predictable.
  - Regulation objectives meet environmental as well as economic and social objectives.
  - Regulation is constantly reviewed to assess its ongoing relevance.
- Underpinned by sound science and evidence:
  - An evidence-based approach should be adopted based on rigorous and reliable information and centred on well-defined risks and environmental values.
  - Information, science and evidence used to underpin regulations should be transparent.
- Risk-based and focused:

  - Objective and risk-based regulation should be adopted rather than prescriptive standards.
  - This allows a flexible and dynamic approach adapting to changing circumstances (technology, environments, science and financial arrangements), and allows actions to be taken to mitigate risk in conditions of scientific uncertainty rather than stopping or banning projects or activities.
- Appropriate to the nature and scale of the project
  - Regulation should be focussed on what is appropriate to the 'nature and scale' and to the risks and impacts from the activity being regulated.
  - The ongoing compliance activity and costs imposed on governments and proponents are appropriate and proportional to the risks and impacts.
- Transparent processes supported by guidance on regulator expectations.

APPEA considers that recent changes updates to the NT regulatory framework are a positive move and represent best practice regulation. The industry will work with the NTG to progress reforms in areas such as whole of Territory environment regulation and to continue the previously proposed reforms to the Petroleum Act, in particular around resource management.

14.9. Regulatory capture

Regulatory capture	There may be a risk of 'regulatory capture' whereby the regulatory body becomes inappropriately aligned with industry and reluctant to regulate.

APPEA believes that the risk of regulatory capture and innapropriate influence from anti or pro industry advocates is significantly reduced when regulation is developed or amended to follow the principles outlined in section 14.8 above.

14.10. Cumulative risks

Cumulative risks	There may be cumulative risks associated with some or all of the risks identified above.

The existing approvals processes are adequate to asses the cumulative risks associated with the nature and scale of unconventional gas activity in the NT.

15. Appendix 1. Questions and Answers to issues raised in Community Consultations

In reviewing the inquiry material and the recent community consultation sessions conducted by the inquiry, APPEA observed a number of questions relating to the development of natural gas. This section aims to address some of the questions raised.

15.1. Question 1: Can you see massive fracking flares from space?

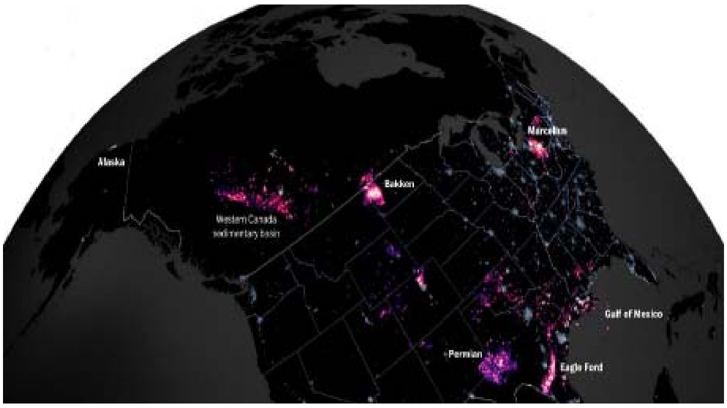
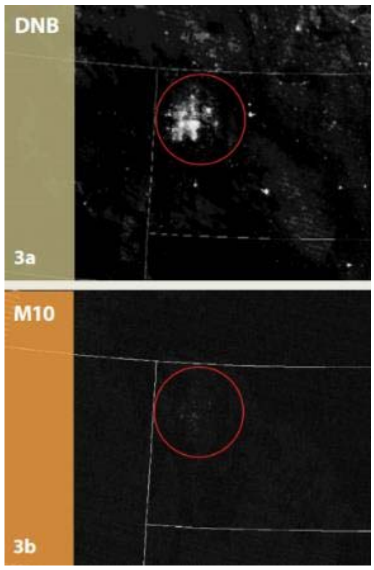


Image 14. An image of Natural Gas Flares in America (source: Lock the Gate submission)

It would be very difficult to see flares from space. A typical flare only occupies a 1/6000 fraction of a satellite pixel (800 m × 800 m), any contamination can easily skew the estimate of flares.

Images such as the one above are misleading in that they give the uninformed public the idea that flares are literally lighting up many square miles of countryside, creating visible light similar to large metropolitan areas. A report from University of North Dakota Energy and Environmental Research center describes how the the photographs have been enhanced (by the wide range of wavelengths) to make it appear the gas flares are the source of huge amounts of light.[92]



The image uses the NASA VIIRS (Infrared Imaging) satellite to pick out and digitally enhance wavelengths of well flares as a composite over 4 years. A more accurate representation is included.

Satellite images of Bakken flares derived from VIIRS satellite spectral bands DNB (top) and M10 (bottom). The picture in Figure 3a is a typical, highly sensitive DNB image showing accumulative light saturation. Figure 3b, in contrast, is the same area with a near-infrared spectral image showing faint, yet discernible, infrared heat signatures, more characteristic of what flares look like from space in the Bakken oil play region of western North Dakota.

Light pollution from flaring and illumination of onshore gas development infrastructure is a real consideration for industry and may impact on the visial amenity of remote areas. As noted in earlier sections of this submission, the

[92] Zhang, X. (2015), B*akken flares and satellite images the science and the facts*, University of North Dakota Energy & Environmental Research Center, www.undeerc.org/bakken/pdfs/Bakken_Flares_and_Satellite_Fact_sheet_2015.pdf

industry comprehensively considers and designs infrastructure to mitigate against light pollution. This can include:

- Using low pressure sodium lighting
- Using timers to reduce the time lighting is used
- Installing movement sensors
- Pits and containment for flaring
- Avoid flaring at night

15.2. Question 2: Can drilling and fracturing for natural gas cause earthquakes?

The risks associated with induced seismicity is low. No correlation has been found between any earthquakes recorded by Geoscience Australia's Australian National Seismograph Network (ANSN) and oil and gas activities in Australia (link).

Small seismic events have been known to result from stress changes in the ground due to human activities in areas that are already suspetible to earthquakes. In oil and gas activities there is literature that suggests small seismic events can be trigger by waste water reinjection, and some emerging studies are also considering hydraulic fracturing. As noted by Chief Scientist Mary O'Kane the "*possibility of induced earthquakes may be greater in the related process of wastewater disposal reinjection, especially when this is done at greater depths than for production."* (NSW Chief Scientist Mary O'Kane). As noted above, industry practice is to treat wastewater on site and/or remove waste material to a licenced waste disposal facility.

Australian is a stable continental region. Earthquakes are infrequent compared to those in plate boundary settings – such as parts of the US, and Pacific Rim countries to Australia's north. "*It is important to note that generally a site that is susceptible to induced earthquakes generally has a pre-existing susceptibility to natural earthquakes. This means that the earthquake that would have occurred eventually without any artificial trigger mechanism* (without being induced). (NSW Chief Scientist Mary O'Kane).

15.3. Question 3: Is depleted uranium used to "perforate" wells?

The oil and gas industry does not use depleted uranium in wells, but it's not a silly question. There are some patents in America that consider using depleted uranium for well perforation which is where this myth originated. Radioactive elements are used in some precise measurement tools in the industry. Depleted uranium (DU) is a very dense material (1.7 times more dense than lead) which is why it is used by the military in armour piercing tank shells.

Depleted uranium is chemically identical to and less radioactive than natural uranium. Uses of DU take advantage of its very high density of 18.95 g/cm^3 (68.4% denser than lead). Depleted uranium has a wide range of civilian applications. For example, it is used in health care (radiation shielding in equipment used for radiation therapy and containers for radioisotopes), aviation (passenger aircraft counterweights) and boat building (ballast counterweight).

We are not aware of anyone in the industry using depleted uranium (in Australia or internationaly) for the purpose of perforating wells. It is not a very good material as it clogs the perforation channels and thus the high density doesn't provide any benefit. Some patents mention the use of depleted uranium for perforating as an alternative material, but there is no engineering basis to use it. It should also be noted that DU is the uranium leftover after enrichment for use in nuclear power plants. There is no commercial source of DU in Australia.

15.4. Question 4: Does natural gas drilling make groundwater radioactive?

Drilling for natural gas doesn't make groundwater radioactive, though the groundwater may already be naturally radioactive.

Naturally occurring radioactive substances are frequently found in groundwater and soils around Australia. The concentration of radiation depends on the surrounding geology. Radiation is present to some extent in all rocks and soils. This is referred to as a Naturally Occurring Radioactive Material (NORM). NORM also exists in air, water, soil and rock. Even food like bananas, Brazil nuts and carrots contain NORM.[93]

Trace elements of radioactive materials are naturally found in Australian groundwaters, such as arsenic, boron, barium, iron, manganese, lead, iron, selenium and uranium and fluoride. The radiological quality of water is addressed at considerable length by Australian and international guidelines (such as the ANZECC Guidelines for Groundwater Protection). [94]

NORM can be brought to the surface by many types of human activity and the risks are already well understood and managed across the different extractive industries.

- The Guidelines for Groundwater Protection in Australia – Literature Review http://www.ga.gov.au/corporate_data/71401/71401.pdf
- ANZECC Guidelines for Groundwater Protection http://www.nhmrc.gov.au/_files_nhmrc/publications/attachments/eh52_aust_drinking_water_guidelines_update_131216.pdf

15.5. Question 5: Is 85% of the NT covered by shale gas and shale gas permits?

Exploration titles are generally large to allow explorers to fully look for and assess a petroleum system. This is a common feature of exploration titles as renewals of tenure reduce in size as knowledge improves and explorers focus their efforts. Unfortunately, most exploration efforts are ultimately commercially unsuccessful. Production titles are small and localised only around an identified petroleum resource.

Approximately 80% of the Northern Territory is covered by 191 exploration permits or applications. The majority of these (128 permits) are areas under *application* with no activity.

Approximately 29% (412,760 sqkm) of the NT is covered by the 63 active, granted petroleum titles. Eight of these titles are producing (or retention titles) in the Amadeus Basin.

[93] ANZECC/ARMCANZ (2000), *Australian and New Zealand Guidelines for Fresh and Marine Water Quality*, National Water Quality Management Strategy, Paper No.4, Vol 1. www.environment.gov.au/system/files/resources/53cda9ea-7ec2-49d4-af29-d1dde09e96ef/files/nwqms-guidelines-4-vol1.pdf

[94] Kleinschmidt, R. (2011), *Radioactive residues associated with water treatment, use and disposal in Australia*, Thesis, Queensland University of Technology. eprints.qut.edu.au/48058/1/Ross_Kleinschmidt_Thesis.pdf

15.6. Question 6: Is it true that a "2003 Schlumberger report" shows that well integrity is a significant problem?

This 2003 report is often cited by industry crticis. This report is entitled "*From Mud to Cement – Building Gas Wells*" and is generally misunderstood.[95]

The report undertakes an analysis of 8,000 offshore wells in the Gulf of Mexico and shows that a percentage of wells developed pressure in the outer strings (called "sustained casing pressure"). This is not a well failure. Sustained Casing Pressure (SCP) is a term that refers to a pressure build up somewhere in the multiple strings of casing. Wells are designed to allow for this. Well maintenance programs address these issues, in the same way we add pressure to tyres on a car. The very low failure rates of wells supports this.

Even when a SCP issue may result in a well barrier issue, there are multiple safety barriers and there must be a pressure or buoyancy gradient for fluids to migrate.

15.7. Question 7: I've heard that "Cement can't last forever".

There's no reason why it can't. This quote is often used by industry opponents and claims that over time all plugged and abandoned gas wells will leak.

Modeling and analysis into well corrosion show a different picture. Yamaguchi, Shimoda, Kato, Stenhouse, Zhou, Papafotiou, Yamashita, Miyashiro & Saito (2013) have investigated the long-term corrosion behaviour of cement in abandoned wells under CO_2 geological storage conditions by simulating the geochemical reactions between the cement seals over a simulated period of 1,000 years. While alteration of the cement seals was found after a period of time, the alteration length after 1,000 years was approximately one meter, leading to the conclusion that cement would be able to isolate CO2 and upper aquifers over the long-term.[96]

15.8. Question 8: Is it true that 6-7% of new wells drilled in each of the past three years already have compromised structural integrity?

This statement is false. Petroleum engineer George E. King explained it well in an International Society of Petroleum Engineers presentation when he said, "*Actual well integrity failures are very rare. Well integrity failure is where **all** barriers fail and a leak is possible. True well integrity failure rates are two to three orders of magnitude lower than single barrier failure rates*."

Chris Tucker, spokesman for industry-supported group Energy in Depth, said what they measured may not be leaks but state inspectors detecting pressure buildup.

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[95] Bruffao, C. et al. (2003), *From Mud to Cement—Building Gas Wells*, Oilfield Review, Autumn 2013, 15:3. www.slb.com/resources/publications/industry_articles/oilfield_review/2003/or2003aut06_building_gas_wells.aspx

96 Kohei Yamaguchi, Satoko Shimoda, Hiroyasu Kato, Michael J. Stenhouse, Wei Zhou, Alexandros Papafotiou, Yuji Yamashita, Kazutoshi Miyashiro, Shigeru Saito, *The Long-term Corrosion Behavior of Abandoned Wells Under CO2 Geological Storage Conditions: (3) Assessment of Long-term (1,000-year) Performance of Abandoned Wells for Geological CO2 Storage*, Energy Procedia, Volume 37, 2013, Pages 5804-5815, ISSN 1876-6102, www.sciencedirect.com/science/article/pii/S1876610213007467.

"The trick these researchers are pulling here is conflating pressure with leakage, trying to convince folks that the mere existence of the former is evidence of the latter."

The Associated Press recently completed an investigation of water contamination and well integrity in four of the most prolific oil and gas states.

It found no confirmed cases of water contamination in Texas; in Ohio there were only six cases; in West Virginia there were four. Finally, based on Pennsylvanian data, the AP found a well failure rate of only about one-third of one percent (0.33 percent) of all the oil and natural gas wells drilled in Pennsylvania since 2005.

15.9. Question 9: Is the emissions footprint for natural gas higher than previously thought?

No. This false claim was made in a number of written submissions to parliamentary inquiries by Lock the Gate. When challenged, the group was forced to admit that it had misled both the NSW Legislative Council and the Australian Senate.[97]

In the Australian context, in 2014 the CSIRO[98] made direct measurements of 43 individual CSG wells in Australia. Its researchers measured a median methane emission for a well of 0.6 g/min, which is about the same as four cows. These measured emission rates are very much lower than those that have been reported for US unconventional gas production.

Ground surveys made between Dalby and Roma over about an 18-month period showed that ambient concentrations in the region were generally consistent with normal seasonal background concentrations, averaging between about 1.75 to 1.80 ppm CH4 (dry basis).

However, there were many instances where elevated levels of CH4 were detected. The peak concentration perturbations in these regions ranged from less than 20 parts per billion (ppb) to almost 20 parts per million (ppm) or more than 10 times background levels. The sources of these CH4 peaks were identified as CSG infrastructure, agricultural activities, natural biogenic sources and ground seeps.

This example highlights the need to ensure that evidence relied on is fact based, relevant to the industry in Australia rather than overseas examples, and reflects scientific consensus.

15.10. Question 10: A 2011 Cornell study suggests that natural gas produces more harmful emissions than coal, is this true?

The 2011 Cornell study citing an 8 percent loss of the total methane produced from every shale well has been refuted by four subsequent 2011 studies.

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[97] Robins, B. (2011), *Coal seam gas claims were 'falsified'*, 21 September 2011, www.smh.com.au/environment/coal-seam-gas-claims-were-falsified-20110920-1kjms.html

[98] Day, S., Dell'Amico, Fry, R., Javanmard Tousi, H., (2014). *Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities.* CSIRO, Australia. www.environment.gov.au/climate-change/greenhouse-gas-measurement/publications/csg-fugitive-emissions

Each of those studies concluded that methane gas is much less harmful, in terms of emissions, than coal. Using scientifically verified data, several universities and corporations have calculated actual methane losses over the life of a shale-gas well at less than 1 percent total.

Also, total emissions of carbon dioxide, nitrous oxides and sulfur oxides, as well as toxins such as mercury, are either absent in shale-gas production or sharply lower than those of coal.

15.11. Qustion 11: A report by the Australia Institute shows that Australian vastly underesimates fugitive emissions.

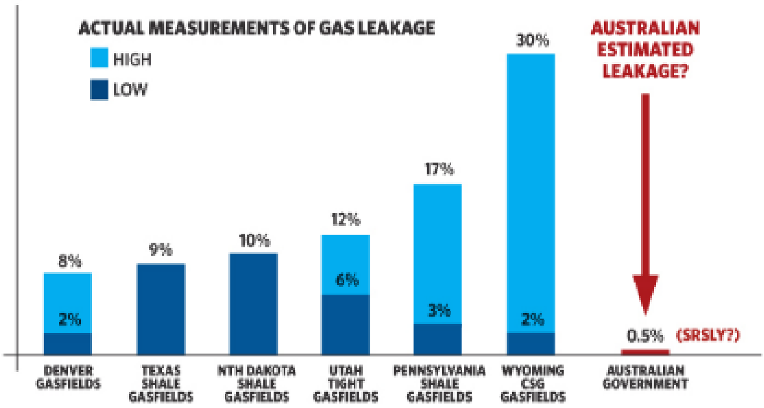

Image 15 Slide from lock the gate

This chart, and the report it is based on is misleading. The Australia Institute report unfortunately cherry picked data samples and refered to outlier figures. Many industry opponents have picked up on this number as representative of the whole industry, which is incorrect. Despite these outliers, the report acknowledges that US EPA's updated position is that methane emissions represent 1.4% of total gas production – well below the 3% to 8 % thresholds mentioned above.

The industry meets all its estimation, measurement and reporting obligations under the *National Greenhouse and Energy Reporting Act 2007* – there is no misreporting or under-reporting of emissions.

Any reference to losses of 6% is not realistic as outlined in the above sections. I.e. this would be several orders of magnitude greater than reputable estimates of actual losses.

15.12. Question 12: Are communities affected by CSG mining experiencing a range of chronic health problems?

This statement is at odds with the findings of an investigation into these claims by health authorities.

According to Queensland Health, no link has been found between coal seam gas operations and health concerns. Queensland Health did however find that the nature of complaints meant there were multiple potential causes and explanations that are not related to CSG activities including faecal contamination in the water supply, the use of wood-fired heaters or open fires, and rainwater contaminated with bacteria, viruses or other organisms.

A further reference is the ongoing Monash University Health Watch Study which has been studying the health of around 19,000 past and present Australian petroleum industry workers since 1980.

The Monash research clearly shows that petroleum industry employees have better health than the general Australian community and are less likely to die of the diseases commonly causing death - including cancer, heart and respiratory conditions.

15.13. Question 13: Is hydraulic fracturing a new process?

Hydraulic fracturing has been around for a long time. The development of hydraulic fracturing can be traced to the 1860s, when liquid (and later, solidified) nitroglycerin was used to stimulate shallow, hard rock wells in Pennsylvania, New York, Kentucky, and West Virginia. Nitroglycerin was extremely hazardous, but was successful for oil wells. In the 1930s, the idea of injecting a less explosive fluid into the ground to stimulate a well began to be tried.

In 1947, Stanolind Oil conducted the first experimental hydraulic fracturing treatment on the Klepper No. 1 well in the Hugoton field located in southwestern Kansas. The treatment used gelled gasoline and proppant - sand from the Arkansas River. J.B Clark and Stanolind (later Amoco and then BP) released a paper on the process in 1948 and a patent for "hydrafrac" was issued in 1949. The paper was entitled "*A Hydraulic Process for Increasing the Productivity of Wells* (1949)".[99] This is the formula we continue to use today.

Since Stanolind Oil introduced hydraulic fracturing in 1947, close to 2.5 million hydraulic fracture treatments have been performed worldwide.

In Australia, hydraulic fracturing has mostly occurred in New South Wales and Queensland since the 1990s. In the Cooper basin in South Australia, approximately 70 wells in total have been hydraulically fractured. Of the approximate 50 more recent wells that have been drilled specifically targeting shale or tight gas in the Copper Basin, approximately 15 have conducted hydraulic fracturing operations[100]. Hydraulic fracturing in the Cooper Basin has occurred without incident.

In Western Australia, hydraulic fracturing has been used extensively to assist with the recovery of gas from conventional resources with an estimated 800 wells having been hydraulically fractured since 1958[101]. Indeed, micro fracturing process has been utilised to recover gas reserves from the environmentally sensitive Barrow Island since the 1970s.

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[99] See: deg.aapg.org/Portals/0/documents/FrackingPatents.pdf

[100] Cook, P., Beck, V., Brereton, D., Clark, R., Fisher, B., Kentish, S., Toomey, J. and Williams, J. (2013), *Engineering Energy: Unconventional Gas Production: A Study of Shale Gas in Australia,* Australian Council of Learned Academies

[101] Department of Mines and Petroleum, *Gas Fact Sheet: Hydraulic Fracture Simulation,* Government of Western Australia

15.14. Question 14: Is "slickwater" fracking more risky than older fracking techniques previously used in the gas industry?

There is no scientific evidence that risks associated with 'slick-water' hydraulic fracturing are higher than other forms of fracturing, and there is no reference in the fact sheet. This is an activist attempt to address the fact that fraccing has been in use since 1949, by suggesting that this 'new' fraccing is different.

15.15. Question 15: What is slickwater?

There are primarily three types of fracturing fluids currently used. Thes are water frac (or slick water), linear gel, and crosslinked gel. All three of these fluids have different properties and applications and are used based on the type of well and a range of other factors such as geology, proppant type, density of the proppant layer etc. It is important to note that other (non-slickwater) treatments are becoming more popular.[102]

- Linear gel is water containing a gelling agent like guar. It may also contain other additives such as biocide, surfactants, and clay control. This fluid has a medium viscosity which results in improved proppant transport and wider frac. It is used in both gas and oil wells.
- Crosslinked gel is water containing gelling agents used in linear gel and a *crosslinker* like boron (B), zirconium (Zr), titanium (Ti) or aluminum (Al). This fluid has a high viscosity which results in better proppant transport and wider fracs compared to other fluids. It is commonly used in oil and high liquid wells.
- Water frac (slickwater) is water containing a friction reducer and possibly a biocide, surfactant, breaker or clay control additive. This fluid has low viscosity and therefore requires higher pump rates to transport the proppant. It is commonly used in gas wells.

Slickwater fracturing is a method or system of hydro-fracturing which involves adding chemicals to water to increase the fluid flow. Mitchell Energy had been innovating in the Barnett Shale since the early 1980's – knowing there was significant amounts of gas, but unable to economically recover it.[103] Mitchell Energy employed a number of hydraulic fracturing treatments – including slickwater. Performance improved and by 1999 the company had achieved economic recovery. In 2001, Devon Energy acquired Mitchell Energy and combined their expertise in hydraulic fracturing with horizontal well drilling. This is the point considered to be the worldwide breakthrough for shale development.

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102 Cook, P, Beck, V, Brereton, D, Clark, R, Fisher, B, Kentish, S, Toomey, J and Williams, J (2013). *Engineering Energy: Unconventional Gas Production*. Australian Council of Learned Academies (ACOLA), www.acola.org.au.

[103] George Waters et al., Use of Horizontal Well Image Tools to Optimize Barnett Shale Reservoir Exploitation 1 (Soc'y of Petroleum Eng'rs, SPE 103202, 2006), available at http:// www.onepetro.org/mslib/servlet/onepetropreview?id=SPE-103202-MS; see also Daniel Yergin, The Quest: Energy, Security, and the Remaking of the Modern World ch. 16 (2011).

15.16. Question 16: Will the water used in fracking put severe pressure on the Territory's underground water resources?

This question was addressed in the report on hydraulic fracturing in the Northern Territory by Allan Hawke AC. As noted in that report:

- The projected water requirements for fracturing are small relative to total water availability at NT or regional scales.
- Moore (2012) estimated that the water requirement of a shale gas well over a decade was equivalent to that needed to water a single golf course for one month, or to run a 1,000 MW coal-fired power plant for 12 hours.

The report's projection of 1.5-2.4 GL/year of total ground water extraction for fracturing activity for the entire NT falls within the range of maximum water entitlements recently granted to individual properties or enterprises in the Daly/Roper water Control District.

15.17. Question 17: Will wildlife migration be restricted by big above surface pipelines?

This has been an issue in other countries. In Australia all pipelines undergo significant environmental approvals. It is important to note that most pipelines in Australia are buried.

16. Appendix 2 Fracturing Chemicals: Regulations and procedures in Queensland and NSW

QUEENSLAND

Risk	Legislation/ instrument	Description	How risk is mitigated
Transport risks – e.g. traffic accident, leakage, operator exposure	Australian Dangerous Goods code	Relevant provisions enacted through state legislation (Transport Operations (Road Use Management) Act in QLD	Sets out a range of requirements for workers and organisations including training, routes, goods too dangerous to be transported by road, packaging, incompatibility etc. Also places specific duties on consignors, packers, loaders and drivers to comply with the ADG Code http://www.ntc.gov.au/heavy-vehicles/safety/australian-dangerous-goods-code/
	Dangerous Goods Driver Licence	Operator training for avoiding issues and managing emergencies	Ensures drivers have the training to act appropriately http://www.qld.gov.au/transport/licensing/driver-licensing/applying/dangerous/driver/index.html
	Dangerous Goods Vehicle Licence	Vehicle operation and technical specification requirements	Ensures vehicles are of appropriate specification, condition and equipped http://www.qld.gov.au/transport/licensing/driver-licensing/applying/dangerous/vehicle/index.html
	Dangerous Goods Documents	Records and Emergency Procedure Guide	Enable compliance to be established regarding the transport of the chemicals, as well as assisting in appropriate responses to emergency situations such as spills http://www.tmr.qld.gov.au/~/media/busind/accreditations/Dangerous%20goods/dangerousgoodsgeneralinfofactsheet.pdf
	Work Health and Safety Act 2011	Duty to do everything reasonably practical to keep workers and the general public safe, including adequately addressing risk of chemical exposure	Incumbent upon chemical transport companies to have systems in place to ensure their staff are protected from risks such as crashes and spills. These are in combination with the specific requirements and duties set out in the Dangerous Goods Code. https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WorkHSA11.pdf https://www.worksafe.qld.gov.au/injury-prevention-safety/managing-risks
	General Environmental Duty	Requirement of the Environmental Protection Act to do everything reasonable and practical to avoid causing harm to the environment.	Incumbent upon chemical transporters to ensure that risks of spilling chemicals (both during transit and transfer operations) are mitigated. These could include only transferring chemicals in contained hardstand areas, having spill response procedures etc.) https://www.ehp.qld.gov.au/management/planning-guidelines/legislation/general_environmental_duty.html
	Waste tracking requirements		Applies to frack flowback transport – requiring detailed records to demonstrate compliance with the relevant waste management requirements for the particular waste

	for waste transport (EP Act)		http://www.ehp.qld.gov.au/waste/pdf/managing-wt-qld-overview.pdf
Off-tenure product handling risks – e.g. worker contact during bulk mixing and preparation of chemicals; spillage of chemicals; chemical fire	*Environmental Protection Act 1994; Environmental Protection Regulation 2008* – ERA 8	Storing 200t or more of chemicals triggers Environmentally Relevant Activity 8 - "Chemical Storage". In order to legally undertake this activity an environmental authority (EA) is required. This EA contains conditions which are specific to the operation and require environmental risks to be mitigated. Conditions will likely include bunding and storage requirements (in line with relevant Aust. Standards), emergency response procedures, training, monitoring and reporting requirements.	Will ensure that environmental risk of the chemical storage and handling activities is adequately controlled. It would be unlikely such a facility would be approved in close proximity to aquatic ecosystems or other environmentally sensitive areas. https://www.ehp.qld.gov.au/licences-permits/business-industry/index.html https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/EnvProtR08.pdf
	Work Health and Safety Act 2011	Duty to do everything reasonably practical to keep workers and the general public safe, including adequately addressing risk of chemical exposure and spills	Incumbent upon chemical storage companies to have systems in place to ensure their staff and the public are protected from risks such as spills and exposure to chemicals. There is also a duty for all staff to follow safety systems and protect themselves and others. These are in combination with the specific requirements of the relevant EA. https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WorkHSA11.pdf https://www.worksafe.qld.gov.au/injury-prevention-safety/managing-risks
	Sustainable Planning Act 2009	Such a facility would require a development approval assessed against the local	If the facility was to be approved in the proposed location it would have a range of conditions about how the site was to be developed and operated in order to ensure safety and consistency with adjacent land uses. http://www.dsdip.qld.gov.au/resources/publication/guide-to-spa.pdf

		planning scheme and relevant state planning instruments. These would include public safety, bushfire risk, proximity of sensitive receptors, proximity of wetlands and many other considerations.	
On-tenure chemical handling (pre-fracture) E.g. worker exposure to chemicals; chemical release to the environment while mixing/preparation	Environmental Protection Act – Resource Activities	The undertaking of activities under the *Petroleum and Gas (Production and Safety) Act 2004* is classed as an Environmentally Relevant Activity. In order to legally undertake this activity an environmental authority (EA) is required. This EA contains conditions which are specific to the operation and require environmental risks to be mitigated. Due to the risks of fracking it is specifically conditioned. A range of more general conditions also apply to the chemical handling associated with fracking.	- A blanket prohibition of releasing chemicals to land - a requirement that chemicals must be contained and comply with relevant Aust. Standards - notification of chemical spills - prohibition of activities within 200m of HES wetlands - prohibition on releasing contaminants to waterways - development of contingency procedures for emergencies including risk mitigation measures, remediation measures and investigative procedures - a site specific risk assessment of hydraulic fracturing activities to avoid environmental harm and including a list of chemicals to be used and an environmental hazard assessment for these chemicals and human health exposure pathways to operators and the general population - no use of BTEX or PAH compounds -no oil or synthetic based drilling muds - Monitoring standards and requirements - Laboratory analysis standards http://www.ehp.qld.gov.au/management/non-mining/documents/guide-model-conditions-petroleum.pdf https://www.ehp.qld.gov.au/management/non-mining/documents/application-requirements-petroleum-guideline.pdf
	Petroleum and Gas (Production and Safety) Act 2004 – Chapter 9	A safety management plan is required for "operating plant" which would be interpreted to	Sets out personal responsibility for safety matters and requires a risk based approach to controls, training, skills and standards. A failure to address safety and health risks associated with chemical handling would be subject to high penalties.

	– Safety management plan	include fracturing operations, and associated chemical handling. Section 675 of the Act stipulates a detailed list of requirements for SMPs.	Competency requirements for well service workers are also set out through relevant standards under the P&G Act. http://mines.industry.qld.gov.au/safety-and-health/safeop.htm https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0015/240702/competency-std-p-g-well-drilling.pdf
Loss of sub-surface containment of fracture fluids risks; e.g. contamination of aquifers; contamination of groundwater resources	Well construction and abandonment code	Sets out the minimum requirements in relation to well design, casing, cementing, control equipment, fluids, logging and monitoring.	Ensures that the well will maintain its integrity and not release chemicals into formations other than the target formation. Deals with risks such as casing failure, cementing isolation etc. to ensure that chemicals do not leak out of the well or migrate between formations. https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0011/119666/code-of-practice-csg-wells-and-bores.pdf
	Petroleum and Gas (Production and Safety) Regulation 2004 R20, r20A	Require a notice of intent to fracture and a notice of completion of fracturing, as well as drilling reports with technical detail around fracturing operations.	Provides government and landholders with an opportunity to comment if any issues are raised with the notice of intent. Also provides specifics to allow rapid responses and ensure compliance. https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/P/PetroleumR04.pdf
	Petroleum and Gas (Production and Safety) Act 2004 – Chapter 9 – Safety management plan	A safety management plan is required for "operating plant" which would be interpreted to include fracturing operations. Section 675 of the Act stipulates a detailed list of requirements for SMPs.	Sets out personal responsibility for safety matters such as well failure and requires a risk based approach to controls, training, skills and standards. A failure to address safety and health risks associated with chemical handling would be subject to high penalties. http://mines.industry.qld.gov.au/safety-and-health/safeop.htm
	Environmental Protection Act 1994– Chapter 5, ERA for Resource Activities	The undertaking of activities under the *Petroleum and Gas (Production and Safety) Act 2004* is classed as an Environmentally Relevant	- a detailed site specific risk assessment of hydraulic fracturing including environmental and geotechnical factors and cumulative impacts to avoid environmental harm *detailed requirements below - notification of incidents including impacting the water quality of aquifers and causing the interconnection of aquifers - practices and procedures to detect the interconnection of aquifers as soon as practical

		Activity. In order to legally undertake this activity an environmental authority (EA) is required. This EA contains conditions which are specific to the operation and require environmental risks to be mitigated. Due to the risks of fracking it is specifically conditioned. A range of more general conditions also apply to fracking.	- demonstration that 150% of the volume of fluid injected into the well has flowed back - extensive pre- and post-fracturing groundwater quality monitoring (including nearby landholder bores)** - flowback water monitoring** - post-event monitoring must continue for at least 5 years - prohibition on releasing contaminants to waters - development of contingency procedures for emergencies including risk mitigation measures, remediation measures and investigative procedures - no use of BTEX or PAH compounds -no oil or synthetic based drilling muds - Monitoring standards and requirements - Laboratory analysis standards http://www.ehp.qld.gov.au/management/non-mining/documents/guide-model-conditions-petroleum.pdf
Handling of chemicals post-fracture (on tenure) risks – e.g. soil contamination; seepage into shallow groundwater; worker exposure; exposure in final waste management solution	*Environmental Protection Act 1994*– Chapter 5, ERA for Resource Activities	The undertaking of activities under the *Petroleum and Gas (Production and Safety) Act 2004* is classed as an Environmentally Relevant Activity. In order to legally undertake this activity an environmental authority (EA) is required. This EA contains conditions which are specific to the operation and require environmental risks to be mitigated. Due to the risks of fracking it is specifically conditioned. A range of more general conditions also apply to fracking.	- a detailed site specific risk assessment of hydraulic fracturing including potential environmental and human health risks for water quality and air impacts - notification of incidents - prohibition on releasing contaminants to waters - prohibition on releasing contaminants to land - all waste fluids must be stored in an above ground container (e.g. tank) or in a dam or pond which contains the wetting front - strict standards for the design, construction and operation of dams, including items such as double lining, leak detection and appropriate design storage allowances http://www.ehp.qld.gov.au/land/mining/pdf/guide-structures-dams-levees-mining-em634.pdf - requirements for annual monitoring of dams and certification and re-certification of medium and high risk dams by suitably qualified registered engineers https://www.ehp.qld.gov.au/land/mining/pdf/mn-mi-assess-haz-cat-hyd-perf-dams-em635.pdf - a seepage monitoring program must be developed by a suitably qualified person in order to detect contaminants escaping from ponds or dams*** - development of contingency procedures for emergencies including risk mitigation measures, remediation measures and investigative procedures - requirement to site major ponds outside of environmentally sensitive areas and associated buffers - no use of BTEX or PAH compounds -no oil or synthetic based drilling muds - any contaminated land is remediated and rehabilitated - Monitoring standards and requirements - Laboratory analysis standards http://www.ehp.qld.gov.au/management/non-mining/documents/guide-model-conditions-petroleum.pdf

	Environmental Protection Act 1994– Chapter 5, ERA for Resource Activities	EA application requirements for CSG require detailed site specific information regarding how CSG water and associated wastes will be managed	This site specific information will need to identify the amount and quality of water that is expected to be produced from both fractured and non-fractured wells. It must then propose: - how the water will be managed - criteria to measure the effectiveness of the management solution - how waste from water management (including flowback water) will be managed This information will then be used to place appropriate requirements on the environmental authority based on how operations will be undertaken https://www.ehp.qld.gov.au/management/non-mining/documents/application-requirements-petroleum-guideline.pdf http://www.ehp.qld.gov.au/management/non-mining/documents/csg-water-measurable-criteria.pdf
	Petroleum and Gas (Production and Safety) Act 2004 – Chapter 9 – Safety management plan	A safety management plan is required for "operating plant" which would be interpreted to include fracturing operations, and associated post-fracture waste management. Section 675 of the Act stipulates a detailed list of requirements for SMPs****.	Sets out personal responsibility for safety matters and requires a risk based approach to controls, training, skills and standards. A failure to address safety and health risks associated with chemical handling would be subject to high penalties. http://mines.industry.qld.gov.au/safety-and-health/safeop.htm Competency requirements for well workers are also set out through relevant standards under th P&G Act. https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0015/240702/competency-std-p-g-well-drilling.pdf

***Detailed stimulation risk assessment requirements**

The stimulation risk assessment must be carried out for every well to be stimulated prior to stimulation being carried out at that well and address issues at a relevant geospatial scale such that changes to features and attributes are adequately described and must include, but not necessarily be limited to:

(a) a process description of the stimulation activity to be applied, including equipment and a comparison to best international practice

(b) provide details of where, when and how often stimulation is to be undertaken on the tenures covered by this environmental authority

(c) a geological model of the field to be stimulated including geological names, descriptions and depths of the target gas producing formation(s)

(d) naturally occurring geological faults

(e) seismic history of the region (e.g. earth tremors, earthquakes)

(f) proximity of overlying and underlying aquifers

(g) description of the depths that aquifers with environmental values occur, both above and below the target gas producing formation

(h) identification and proximity of landholder' active groundwater bores in the area where stimulation activities are to be carried out

(i) the environmental values of groundwater in the area

(j) an assessment of the appropriate limits of reporting for all water quality indicators relevant to stimulation monitoring in order to accurately assess the risks to environmental values of groundwater

(k) description of overlying and underlying formations in respect of porosity, permeability, hydraulic conductivity, faulting and fracture propensity

(l) consideration of barriers or known direct connections between the target gas producing formation and the overlying and underlying aquifers

(m) a description of the well mechanical integrity testing program

(n) process control and assessment techniques to be applied for determining extent of stimulation activities (e.g. microseismic measurements, modelling etc.)

(o) practices and procedures to ensure that the stimulation activities are designed to be contained within the target gas producing formation

(p) groundwater transmissivity, flow rate, hydraulic conductivity and direction(s) of flow

(q) a description of the chemical compounds used in stimulation activities (including estimated total mass, estimated composition, chemical abstract service numbers and properties), their mixtures and the resultant compounds that are formed after stimulation

(r) a mass balance estimating the concentrations and absolute masses of chemical compounds that will be reacted, returned to the surface or left in the target gas producing formation subsequent to stimulation

(s) an environmental hazard assessment of the chemicals used including their mixtures and the resultant chemicals that are formed after stimulation including:

i. toxicological and ecotoxicological information of chemical compounds used

ii. information on the persistence and bioaccumulation potential of the chemical compounds used; and

iii. identification of the chemicals of potential concern in stimulation fluids derived from the risk assessment

(t) an environmental hazard assessment of use, formation of, and detection of polycyclic aromatic hydrocarbons in stimulation activities

(u) identification and an environmental hazard assessment of using radioactive tracer beads in stimulation activities

(v) an environmental hazard assessment of leaving chemical compounds in stimulation fluids in the target gas producing formation for extended periods subsequent to stimulation

(w) human health exposure pathways to operators and the regional population

(x) risk characterisation of environmental impacts based on the environmental hazard assessment

(y) potential impacts to landholder bores as a result of stimulation activities

(z) an assessment of cumulative underground impacts, spatially and temporally of the stimulation activities to be carried out on the tenures covered by this environmental authority; and

(aa) potential environmental or health impacts which may result from stimulation activities including but not limited to water quality, air quality (including suppression of dust and other airborne contaminants), noise and vibration

**** fracturing water quality and well monitoring analyte requirements:**

(a) pH

(b) electrical conductivity [µS/m]

(c) turbidity [NTU]

(d) total dissolved solids [mg/L]

(e) temperature [ºC]

(f) dissolved oxygen [mg/L]

(g) dissolved gases (methane, chlorine, carbon dioxide, hydrogen sulfide) [mg/L]

(h) alkalinity (bicarbonate, carbonate, hydroxide and total as $CaCO_3$) [mg/L]

(i) sodium adsorption ratio (SAR)

(j) anions (bicarbonate, carbonate, hydroxide, chloride, sulphate) [mg/L]

(k) cations (aluminium, calcium, magnesium, potassium, sodium) [mg/L]

(l) dissolved and total metals and metalloids (including but not necessarily being limited to: aluminium, arsenic, barium, borate (boron), cadmium, total chromium, copper, iron, fluoride, lead, manganese, mercury, nickel, selenium, silver, strontium, tin and zinc) [µg/L]

(m) total petroleum hydrocarbons [µg/L]

(n) BTEX (as benzene, toluene, ethylbenzene, ortho-xylene, para- and meta-xylene, and total xylene) [µg/L]

(o) polycyclic aromatic hydrocarbons (including but not necessarily being limited to: naphthalene, phenanthrene, benzo[a]pyrene) [µg/L]

(p) sodium hypochlorite [mg/L]

(q) sodium hydroxide [mg/L]

(r) formaldehyde [mg/L]

(s) ethanol [mg/L]; and

(t) gross alpha + gross beta or radionuclides by gamma spectroscopy [Bq/L]

*****Seepage monitoring program requirements**

(a) identification of the containment facilities for which seepage will be monitored

(b) identification of trigger parameters that are associated with the potential or actual contaminants held in the containment facilities

(c) identification of trigger concentration levels that are suitable for early detection of contaminant releases at the containment facilities

(d) installation of background seepage monitoring bores where groundwater quality will not have been affected by the petroleum activities authorised under this environmental authority to use as reference sites for determining impacts

(e) installation of seepage monitoring bores that:

i. are within formations potentially affected by the containment facilities authorised under this environmental authority (i.e. within the potential area of impact)

ii. provide for the early detection of negative impacts prior to reaching groundwater dependent ecosystems, landholder's active groundwater bores, or water supply bores

iii. provide for the early detection of negative impacts prior to reaching migration pathways to other formations (i.e. faults, areas of unconformities known to connect two or more formations)

(f) monitoring of groundwater at each background and seepage monitoring bore at least quarterly for the trigger parameters identified in condition (Water 14(b))

(g) seepage trigger action response procedures for when trigger parameters and trigger levels identified in conditions (Water 14(b)) and (Water 14(c)) trigger the early detection of seepage, or upon becoming aware of any monitoring results that indicate potential groundwater contamination

(h) a rationale detailing the program conceptualisation including assumptions, determinations, monitoring equipment, sampling methods and data analysis; and

(i) provides for annual updates to the program for new containment facilities constructed in each annual return period.

******Safety management plan requirements**

A safety management plan for an operating plant must include details of each of the following to the extent they are appropriate for the plant—

(a) a description of the plant, its location and operations;

(b) organisational safety policies;

(c) organisational structure and safety responsibilities;

(ca) for an operating plant, other than a coal mining–CSG operating plant—the operator of the plant;

(d) each site at the plant for which a site safety manager is required;

(e) a formal safety assessment consisting of the systematic assessment of risk and a description of the technical and other measures undertaken, or to be undertaken, to control the identified risk;

(f) if there is proposed, or there is likely to be, interaction with other operating plant or contractors in the same vicinity, or if there are multiple operating plant with different operators on the same petroleum tenure, geothermal tenure or GHG authority—

(i) a description of the proposed or likely interactions, and how they will be managed; and

(ii) an identification of the specific risks that may arise as a result of the proposed or likely interactions, and how the risks will be controlled; and (iii) an identification of the safety responsibilities of each operator;

(g) a skills assessment identifying the minimum skills, knowledge, competencies and experience requirements for each person to carry out specific work;

(h) a training and supervision program containing the mechanism for imparting the skills, knowledge, competencies and experience identified in paragraph (g) and assessing new skills, monitoring performance and ensuring ongoing retention of skill levels;

(i) safety standards and standard operating and maintenance procedures applied, or to be applied, in each stage of the plant;

(j) control systems, including, for example, alarm systems, temperature and pressure control systems, and emergency shutdown systems;

(k) machinery and equipment relating to, or that may affect, the safety of the plant; (l) emergency equipment, preparedness and procedures;

(m) communication systems including, for example, emergency communication systems;

(ma) a process for managing change including a process for managing any changes to plant, operating procedures, organisational structure, personnel and the safety management plan;

(n) the mechanisms for implementing, monitoring and reviewing and auditing safety policies and safety management plans;

(p) key performance indicators to be used to monitor compliance with the plan and this Act;

(q) mechanisms for—

(i) recording, investigating and reviewing incidents at the plant; and

(ii) implementing recommendations from an investigation or review of an incident at the plant;

(r) record management, including, for example, all relevant approvals, certificates of compliance and other documents required under this Act;

(s) to the extent that, because of the Work Health and Safety Act 2011, schedule 1, part 2, division 1, that Act does not apply to a place or installation at the plant, details, including codes and standards adopted, addressing all relevant requirements under that Act that would, other than for that section, apply;

(t) if the operating plant is, under the NOHSC standard, a major hazard facility—each matter not mentioned in paragraphs (b) to (r) that is provided for under chapters 6 to 10 of that standard

NEW SOUTH WALES

Risk	Legislation/ instrument	Description	How risk is mitigated
Transport risks – e.g. traffic accident, leakage, operator exposure	Australian Dangerous Goods code	Relevant provisions enacted through state legislation *Dangerous Goods (Road and Rail Transport) Act 2008* and *Dangerous Goods (Road and Rail Transport) regulation 2014*	Hazardous materials are substances falling within the classification of the Australian Code for *Transportation of Dangerous Goods by Road and Rail (Dangerous Goods Code)* The EPA regulates the on-road transport of dangerous goods while WorkCover regulates activities prior to transport, including correct classification, packaging and labelling. These are effectively the same as the Queensland regime as they are both based on national model legislation. http://www.legislation.nsw.gov.au/sessionalview/sessional/sr/2014-398.pdf
	Dangerous Goods Driver Licence	Operator training for avoiding issues and managing emergencies	Ensures drivers have the training to act appropriately
	Dangerous Goods Vehicle Licence	Vehicle operation and technical specification requirements	Ensures vehicles are of appropriate specification, condition and equipped
	Dangerous Goods Documents	Records and Emergency Procedure Guide	Enable compliance to be established regarding the transport of the chemicals, as well as assisting in appropriate responses to emergency situations such as spills
	Work Health and Safety Act 2011	Duty to for officers to exercise due diligence to ensure safety of employees and duty of workers to ensure safety of themselves and other persons and comply with instructions	Incumbent upon chemical transport companies to have systems in place to ensure their staff are protected from risks such as crashes and spills. These are in combination with the specific requirements set out in the Dangerous Goods Code. http://www.legislation.nsw.gov.au/maintop/view/inforce/act+10+2011+cd+0+N
	Environmental offences	The *Protection of the Environment Operations Act 1997* provides offences for wilfully or negligently causing harm to the environment.	Incumbent upon chemical transporters to ensure that risks of spilling chemicals (both during transit and transfer operations) are mitigated. These could include only transferring chemicals in contained hardstand areas, having spill response procedures etc.) The Environment Protection Authority (EPA) has the power to inspect and prosecute companies for environmental and health breaches. http://www.epa.nsw.gov.au/legislation/aboutpoeo.htm#P90_6221
	Waste tracking requirements for waste transport	The *Protection of the Environment Operations (Waste) Regulation 2005*	Would likely apply to frack flowback transport – requiring detailed records to demonstrate compliance with the relevant waste management requirements for the particular waste

		implements requirements to track and record the transportation of high environmental risk wastes.	http://www.legislation.nsw.gov.au/inforcepdf/2005-497.pdf?id=15937bef-eef8-c8ed-d2c1-dd4c148cc79c
Off-tenure product handling risks – e.g. worker contact during bulk mixing and preparation of chemicals; spillage of chemicals; chemical fire	Environmental Protection Licence – Chemical Storage	Storing 5,000kL or more of chemicals triggers a requirement for an Environment Protection Licence (EPL). EPLs contains conditions which are specific to the operation and require environmental risks to be mitigated..	Will ensure that environmental risk of the chemical storage and handling activities is adequately controlled. It would be unlikely such a facility would be approved in close proximity to aquatic ecosystems or other environmentally sensitive areas. http://www.legislation.nsw.gov.au/fragview/inforce/subordleg+211+2009+sch.1+0+N?SRTITLE=%22Protection%20of%20the%20Environment%20Operations%20(General)%20Regulation%202009%22&nohits=y&tocnav=y
	Work Health and Safety Act 2011	Duty for officers to exercise due diligence to ensure safety of employees and duty of workers to ensure safety of themselves and other persons and comply with instructions	Incumbent upon companies handling chemicals to have systems in place to ensure their staff are protected from risks such as exposure and spills. These are in combination with the specific requirements set out in the PEL where over the 5,000kL threshold. http://www.legislation.nsw.gov.au/maintop/view/inforce/act+10+2011+cd+0+N
	Environmental Planning and Assessment Act 1979	Such a facility would require a development application be submitted to Council and assessed against the planning scheme and relevant state instruments Goes to joint regional planning panel for regional development.	If the facility was to be approved in the proposed location it would be likely to have a range of conditions, about how the site was to be developed and operated in order to ensure safety and consistency with adjacent land uses. http://www.legislation.nsw.gov.au/maintop/view/inforce/act+203+1979+cd+0+N
On-tenure chemical handling (pre-fracture) E.g. worker exposure to chemicals; chemical release to the environment while	*Protection of the Environment Operations Act 1997*	The undertaking of CSG exploration and production activities triggers a requirement for an Environment Protection Licence	Requires compliance with a range of conditions built around mitigating impacts associated with discharges to land, air and water. Requires the preparation of pollution incident response management plans and or pollution reduction programs for non-compliance with EPL conditions. These conditions have requirements relating to contingency management and chemical storage standards etc. No "model conditions" for CSG EPLs are currently available, however examples can be obtained from various recent approvals.

mixing/preparation			http://www.legislation.nsw.gov.au/sessionalview/sessional/sr/2014-852.pdf
	Petroleum (Onshore) Act 1991 and *Work Health and Safety Act 2011*	The Office of Coal Seam Gas has responsibility for implementation of safety requirements for the CSG, including those around chemical handling and storage. Both pieces of legislation apply.	It is incumbent upon companies handling chemicals to have systems in place to ensure their staff are protected from risks such as exposure and spills. The safety standards for the NSW CSG industry are currently under review with recommendations due early 2015. http://www5.austlii.edu.au/au/legis/nsw/consol_act/whasa2011218/ http://www.legislation.nsw.gov.au/xref/inforce/?xref=Type%3Dact%20AND%20Year%3D1991%20AND%20no%3D84&nohits=y
	Code of Practice for Fracture Stimulation	The Code of Practice for Fracture Stimulation has been approved by the Minister for Resources and Energy and is mandatory for CSG operators	The Code of Practice for CSG fracking provides that chemical use should be minimised and prevents the use of BTEX chemicals. It also requires a fracture stimulation management plan which outlines: - The volumes and concentrations of those chemicals - Potential risks to human health arising from exposure to those chemicals - The risk, likelihood and consequence of surface spills of these chemicals - How those chemicals will be stored and managed. The code also provides for the development of an Emergency Plan dealing with matters such as evacuation procedures, medical treatment and assistance and training requirements. Further, the code provides for the mandatory development of an Environmental Incident Response Plan dealing with matters including chemical spills and other pollution incidents including: - details of the pre-emptive action to be taken to minimise or prevent any risk of harm to human health or the environment arising out of the activity - an inventory of potential pollutants on the premises or used in carrying out the activity, - the maximum quantity of any pollutant that is likely to be stored or held at the location of the fracture stimulation activity - a description of the safety equipment or other devices that are used to minimise the risks to human health or the environment and to contain or control a pollution incident - details of the mechanisms for providing early warnings and regular updates to the owners and occupiers of premises in the vicinity of the fracture stimulation activity - the arrangements for minimising the risk of harm to any persons who are present where the fracture stimulation activity is being carried out http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0018/516114/Code-of-Practice-for-Coal-Seam-Gas-Fracture-Stimulation.PDF
Loss of sub-surface containment	Well Integrity Code	Sets out the mandatory minimum	Requires risk management planning to be applied to well operations in the context of the *Work Health and Safety Act 2011* and further requires a Safety

of fracture fluids risks; e.g. contamination of aquifers; contamination of groundwater resources		requirements in relation to well construction to ensure integrity.	Management Plan to be developed for each stage of well operations. The code details reporting requirements including a record of all work undertaken on a well*. Cementing reports are also required in order to demonstrate isolation. Extensive requirements to ensure that no loss of containment are stipulated in relation to the following: - well design (including casing setting depths accounting for aquifers and production zone locations) - casing (e.g. designed to withstand loads and pressures and meet API standards) - cementing (including cementing from shoe to surface and verification of zonal isolation) - well heads (to API standards) - drilling fluids (including no oil-based muds, records of each chemical used and managed in accordance with MSDS requirements) - evaluation (well downhole survey carried out) - ongoing appropriate monitoring and maintenance - suspension and abandonment (including extensive requirements to ensure safety and integrity of the well into the foreseeable future) http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0006/516174/Code-of-Practice-for-Coal-Seam-Gas-Well-Integrity.PDF
	Code of Practice for Fracture Stimulation	The Code of Practice for Fracture Stimulation has been approved by the Minister for Resources and Energy and is mandatory for CSG operators	Contains extensive detailed requirements and implements a risk based approach to ensuring safety and environmental outcomes in relation to hydraulic fracturing activities. Requires a fracture stimulation management plan* be in place prior to fracturing including in relation to fracture stimulation design, assessment of risks, protection of water resources and monitoring requirements. Further, the code requires an Environmental Emergency Response Plan which deals specifically with loss of well integrity. A completion report must be submitted following fracturing events which demonstrates that no environmental harm has been caused. http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0018/516114/Code-of-Practice-for-Coal-Seam-Gas-Fracture-Stimulation.PDF
	Protection of the Environment Operations Act 1997	The undertaking of CSG exploration and production activities triggers a requirement for an Environment Protection Licence	Requires the preparation of pollution incident response management plans and compliance with a range of conditions. These conditions have requirements relating to the undertaking of fracture stimulation activities. No "model conditions" for CSG EPLs are currently available, however examples can be obtained from various recent approvals. http://www.legislation.nsw.gov.au/sessionalview/sessional/sr/2014-852.pdf
	Strategic Regional Land Use Policy	An Agricultural Impact Statement (AIS) is now required for	A comprehensive Agricultural Impact Statement must be provided by the applicant at both the exploration stage (where there is a requirement for a

		various minerals and petroleum (incl. CSG) activities at the exploration and development application stages	Review of Environmental Factors) and at the development application stage. http://www.resourcesandenergy.nsw.gov.au/miners-and-explorers/rules-and-forms/pgf/guidelines/agricultural-impact-statements
	Water Management Act 2000	A Water Access License is required to take water in the course of undertaking a mining activity.	Determines requirements for taking groundwater, whether for consumption or incidentally, unless an exemption applies. Any new mining and petroleum exploration activities that take more than three megalitres per year from groundwater sources will need to hold a WAL.
Handling of chemicals/flow back post-fracture (on tenure) risks – e.g. soil contamination; seepage into shallow groundwater; worker exposure; exposure in final waste management solution	*Protection of the Environment Operations Act 1997*	The undertaking of CSG exploration and production activities triggers a requirement for an Environment Protection Licence	Requires the preparation of pollution incident response management plans and compliance with a range of conditions. These conditions have requirements relating to the undertaking of fracture stimulation activities. Flowback water is defined as a liquid" waste which must be managed, stored, transported and disposed of in a way that protects the environment and in accordance with the EPL condition requirements. The EPA requires that flowback water must be appropriately stored and transported to a facility that is licensed by the EPA to take that type of waste. All CSG facilities must also keep detailed records of their liquid waste. No "model conditions" for CSG EPLs are currently available, however examples can be obtained from various recent approvals. http://www.legislation.nsw.gov.au/sessionalview/sessional/sr/2014-852.pdf http://www.epa.nsw.gov.au/resources/licensing/150007csgflowbackwater.pdf
	Code of Practice for Fracture Stimulation	The Code of Practice for Fracture Stimulation has been approved by the Minister for Resources and Energy and is mandatory for CSG operators	Contains extensive detailed requirements and implements a risk based approach to ensuring safety and environmental outcomes in relation to hydraulic fracturing activities. Requires a fracture stimulation management plan be in place prior to fracturing including in relation to fracture stimulation design, assessment of risks, protection of water resources and monitoring requirements. It is specifically required to detail the management storage and disposal of flowback water. Further, the code requires an Environmental Emergency Response Plan which deals specifically with spills. A completion report must be submitted following fracturing events which demonstrates that no environmental harm has been caused. http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0018/516114/Code-of-Practice-for-Coal-Seam-Gas-Fracture-Stimulation.PDF
	Petroleum (Onshore) Act 1991 and Work Health	The Office of Coal Seam Gas has responsibility for implementation of safety	It is incumbent upon companies handling chemicals to have systems in place to ensure their staff are protected from risks such as exposure and spills.

	and Safety Act 2011	requirements for the CSG, including those around chemical handling and storage. Both pieces of legislation apply.	The safety standards for the NSW CSG industry are currently under review with recommendations due early 2015. http://www5.austlii.edu.au/au/legis/nsw/consol_act/whasa2011218/ http://www.legislation.nsw.gov.au/xref/inforce/?xref=Type%3Dact%20AND%20Year%3D1991%20AND%20no%3D84&nohits=y

*** Good industry practice well records:**

- Engineering design basis
- Kick tolerance/well control design assumptions
- BOP pressure testing requirements, and actual test records
- Laboratory test results for cement slurries
- Casing tallies for all casing strings run (including lengths, weights, grades, inside diameter, outside diameter, setting depth)
- Cementing records for each casing string in each well
- casing pressure test reports
- Leak off test and/or formation integrity test reports
- Wireline logs
- Core description reports
- Downhole installation records/schematic
- records of chemicals used downhole, including any chemicals used in drilling fluid, treatment and workover or other well procedures (name, type CAS number and volume of each chemical used should be recorded)
- Records of drilling and cementing, including any problems encountered during the drilling
- Risk assessments
- Well drilling and completion programs including casing running and cementing procedures
- Daily rig reports
- Daily geological reports, if relevant
- Service company reports

**** Requirements for fracture stimulation management plans:**

a) Fracture stimulation activities must not be conducted except in accordance with a FSMP approved by the department.

b) The FSMP must describe the nature, location, scale, timing, duration, hours of operation and other relevant features of the fracture stimulation activity.

c) The FSMP must demonstrate that all risks to the environment, existing land uses, the community and workforce, as a result of the fracture stimulation activity, are managed through an effective risk management process that includes identification of hazards, assessment of risks, implementation of control measures and monitoring of the integrity and effectiveness of the control measures.

d) The FSMP must identify how the titleholder will address and comply with the requirements of this Code.

e) The FSMP must be reviewed and as necessary revised by the titleholder:

i. before making a significant change to the design or operation of the fracture stimulation activity

ii. if the sensitivity of potentially affected environmental, land use or community features significantly increases

iii. in the event that monitoring indicates that the consequences of the fracture stimulation activity exceed those identified in the FSMP, or that a risk control measure does not adequately control the risk Fracture Stimulation Activities

f) The detail provided in the FSMP must be appropriate to the nature, scale, intensity and potential impacts of the proposed fracture stimulation activity.

g) The FSMP is a public document and may be published by the department on its website or by other means. Commercially sensitive or personal information should not be included within a FSMP unless specifically required by this Code.

The design of the fracture stimulation activity must be described in the FSMP. This description must incorporate the following:

a) characterisation of geological formations, including the identification of rock types and conditions, aquifers and hydrocarbon-bearing zones

b) definition of distances to these aquifers from the target coal beds

c) identification of the characteristics of intervening strata, including porosity/permeability and the extent of natural fracturing

d) determination of geological stress fields and areas of faulting

e) determination of maximum pressures to be used for fracture stimulation, based on the characteristics of the surrounding geology

f) modelling of the likely fracture propagation field, including extent and orientation

g) discussion of any potential for the fracture propagation field to exceed that modelled in (f).

Risk assessment

a) The FSMP must include a risk assessment complying with AS/NZS ISO 31000:2009 Risk management - Principles and Guidelines.

b) The risk assessment must identify risks associated with the fracture stimulation activity, the likelihood of each risk and the consequence of each risk.

c) The risk assessment must define appropriate management controls to ensure identified risks are constrained to acceptable levels.

d) At a minimum, the risk assessment must address risks associated with:

i. workplace health and safety (see heading 5 of this Code)

ii. public safety (see heading 5 of this Code)

iii. chemical use (see heading 6 of this Code)

iv. impacts on water resources (see headings 7 and 8 of this Code)

v. land contamination

vi. air pollution

vii. noise & vibration

viii. waste management (e.g. flowback water as per heading 8 of this Code)

ix. loss of well integrity

x. induced seismicity

xi. induced subsidence or other induced ground movements

xii. conflicts with existing land uses

Water resources

a) Identify the location, extent, pre-existing water quality and use of water sources which have the potential to be impacted by the fracture stimulation activity.

b) Identify sources of fracture stimulation injection water, the estimated quality and volume to be injected and any licensing/approval requirements under the Water Management Act 2000 or Water Act 1912.

c) Include a qualitative risk assessment for risks associated with the fracture stimulation activity, including:

i. cross-contamination between coal bed waters and shallower water sources

ii. changes to groundwater pressure and levels

iii. changes to surface water levels

iv. changes to water quality characteristics.

d) If the risk of establishing a connection between the target coal bed and other water sources as a result of the fracture stimulation activity is assessed to be moderate or higher, then a fate and transport model study must be undertaken to quantify the impacts on water sources and the likelihood of any changes to the beneficial use category applicable to any affected aquifer.

e) If there is a moderate or greater risk of significant changes to pressure or levels as referred to in c) (ii) or (iii), the impacts on all affected aquifers must be quantitatively assessed.

f) Describe consultation undertaken with the NSW Office of Water in developing the water resources component of the risk assessment.

Monitoring

a) The FSMP must describe any monitoring arrangements, including monitoring before, during and after the fracture stimulation activity.

b) The titleholder must carry out sufficient monitoring to establish that significant risks have been:

i. identified

ii. quantified

iii. avoided, or appropriately managed so that residual risks are within acceptable limits before, during and after the fracture stimulation activity.

c) Monitoring of overlying water sources must be undertaken over an area sufficient to encompass the predicted fracture length plus a sufficient margin to provide for any uncertainty.

d) Prior to fracture stimulation, monitoring must be undertaken to characterise water source level, pressure and quality. This monitoring should include existing wells and water bores at a minimum.

e) During fracture stimulation, monitoring must be undertaken to:

i. record key parameters such as bottom hole pressure and surface injection pressure

ii. establish the volume, composition, viscosity and pumping rate of fracture fluids and proppants

f) Post-stimulation monitoring must be undertaken to ensure that induced inter-aquifer connectivity has been prevented by:

i. determining the volume and quality of flowback and produced water

ii. quantifying any changes in surrounding water sources

iii. pressure testing of casing to verify that the integrity of the well and well equipment has been maintained.

17. Appendix 3. Scientific and Technical reports

17.1. Australia

1. The Australian Council of Learned Academies (2013). *Engineering Energy: Unconventional Gas Production. A study of shale gas in Australia.* ACOLA undertook a three year research program funded by the Australian Research Council, conducted for the Prime Minister's Science, Engineering and Innovation Council (PMSEIC) through the Chief Scientist and his Office. The ACOLA Report includes important findings in relation to landscape and biodiversity, water, induced seismicity, greenhouse gas emissions, community issues, and monitoring, governance and regulation. (link)
2. The NSW Chief Scientist and Engineer (2014). - *Study of Regulator Compliance Systems and Processes for Coal Seam Gas.* Professor Mary O'Kane, delivered her Independent review to the NSW Premier on 30 September 2014 (the final of three volumes). The CSE found that CSG mining in NSW was manageable subject to appropriate safeguards. (link)
3. Allan Hawke AC for the Northern Territory Government (2014). *NT hydraulic Fracturing Inquiry.*
   The Hawke Inquiry itself found that the environmental risks associated with hydraulic fracturing can be managed effectively, subject to the creation of a robust regulatory regime and that there was 'no justification whatsoever for the imposition of a moratorium on hydraulic fracturing in the NT'. (link)

17.2. Scientific and Technical reports (International).

4. Nova Scotia Hydraulic Fracturing Independent Review and Public Engagement Process (2014). This independent panel concluded that that the industry can bring benefits from climate change, public health, and community economic development perspectives. But, as with any industrial activities, there a range of risks and costs. (link)
5. The German Institute for Geosciences and Natural Resources (2016) Schieferöl und Schiefergas in Deutschland - Potenziale und Umweltaspekte. *Shale oil and shale gas in Germany - potential and environmental aspects.* The report concluded that developing Germany's shale gas and oil resources through hydraulic fracturing would not pose a threat to drinking water resources. (Released in German at this link) English summary by Reuters.
6. The New Zealand Parliamentary Commissioner for the Environment (2014)
   The interim report concludes that the environmental risks associated with fracking can be managed effectively. The report quotes the United Kingdom Royal Society, "*operational best practices are implemented and enforced through regulation*". (interim report link)
7. Dr Wright's Final Report (June 2014), '*Drilling for Oil and Gas in New Zealand: Environmental Oversight and Regulation.* (link) The final report identifies regulation that could be improved to manage potential environmental issues. The final report emphasises that the biggest issue is not a local environmental effect, but the potential global effect of climate change. *However,* it does acknowledge that Natural gas is the most benign of the fossil fuels, and when it is used as an energy source instead of coal, carbon dioxide emissions are generally lower.
8. The Council of Canadian Academies (2014). '*Environmental Impacts of Shale Gas Extraction in Canada'* (link) Overall, the Panel found that well-targeted science is required to ensure a better understanding of the environmental impacts of shale gas development.
9. Council of Canadian Academies (2014). '*Harnessing science and technology to understand the environmental impacts of shale gas extraction.'* The report found that uncertainties

exist in assessing potential impacts at individual sites that differ in their geology, hydrology, climate, access infrastructure and socio-economic conditions. (link)

10. The United States Environmental Protection Agency (2015). *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources.* This comprehensive report is almost 1,000 pages long and took four years to compile. The EPA stated[104]: "We did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources". "".

1. The United States EPA (2004) Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. (link)
2. US Groundwater Protection Council. (2011) State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms A Two-State Review: Ohio and Texas (link)
3. UK. House of Commons Energy and Climate Change Committee (2011). Shale Gas.
   The committee of the United Kingdom House of Commons undertook an inquiry into Shale Gas in 2010. The committee found that "hypothetical and unproven risk must be balanced against the energy security benefits that shale gas could provide to the UK." They concluded that "on balance, a moratorium in the UK is not justified or necessary at present."[105] (link)
4. UK. Royal Society and Royal Academy of Engineering (2012). Shale gas extraction in the UK: a review of hydraulic fracturing.[106] The UK Government's Chief Scientific Adviser, Sir John Beddington FRS, asked the Royal Society and the Royal Academy of Engineering to review the scientific and engineering evidence of Shale gas extraction. The final report found that the Health, Safety and Environmental risks associated with hydraulic fracturing can be managed effectively as long as operational best practices are implemented and enforced through regulation. (link)
5. International Energy Agency (2012). Golden Age of Gas.
   This report describes the key environmental and social risks and how they can be addressed and suggests 'Golden Rules' necessary to obtain the economic and energy security benefits while meeting public concerns. (link)
6. French Académie des Sciences (December, 2012). La recherche scientifique face aux défis de l'énergie; Rapport du Comité de prospective en énergie de l'Académie des sciences Ed.[107]
   The scientific report concluded that "Overall, we found that the risks associated with the extraction of shale gas can be controlled with appropriate regulations". The expert report also highlights how France could take advantage in terms of growth, employment, industrial competitiveness and energy independence.
7. Final report of the Impacts of Unconventional Hydrocarbon Exploration in France. (March 2012). The final joint report of the French General Council of Industry, Energy and

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[104] "Assessment of the Potential Impacts…." page ES-6
[105] http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/79505.htm#a4
[106] https://royalsociety.org/~/media/policy/projects/shale-gas-extraction/2012-06-28-shale-gas.pdf
[107] http://www.bibsciences.org/bibsup/acad-sc/common/articles/rapport-defis-energie.pdf

Technology (CGIET) and the General Council of the Environment and Sustainable Development (CGEDD). The report recommends more time to improve the quality of the law based on a better knowledge of the subject. It also recommends the establishment of a national commission to investigate shale oil and gas exploration and development. The law to ban HF and Shale development in France was announced prior to this report being finalised and presented.

8. Dutch Ministry of Economic Affairs (2013) published a report on the potential risks and of shale gas extraction. The report takes the view that the environmental risks associated with extraction are manageable, so long as the correct guidelines are in place.[108] (link)
9. International Risk Governance Council (2013) Risk governance guidelines for unconventional gas development.[109] a (link) This report was generated based on an expert workshop, held in November 2012, an extensive literature review and numerous conversations with experts in academia, scientific institutions, industry, regulatory authorities and policymakers. The report finds that the risks can be managed, but "political legitimacy and local community cooperation" is paramount.
10. Independent Expert panel. Scottish Government. (2013). Report on Unconventional Oil And Gas. An Independent Expert Scientific Panel report on the scientific evidence relating to unconventional oil and gas.[110] The panel found that the impacts can be mitigated if carefully considered. They also found that "the regulatory framework is largely in place to control the potential environmental impacts of the production of unconventional oil and gas in Scotland". (link)
11. German Federal Ministry of the Environment. (2013) Environmental Impacts of Fracking Related to Exploration and Exploitation of Unconventional Natural Gas Deposits. The German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and the Federal Environmental Agency (UBA) presented a study on the environmental impact of shale gas development.[111] The study recommends that hydraulic fracturing should not be banned, but its application should only be allowed with strict regulation in place and should be accompanied by intensive administrative and scientific supervision. (link)
12. European Commission – technical reports. (2013). An overview of hydraulic fracturing and other formation stimulation technologies for shale gas production. (link)
13. Lithuanian Academy of Sciences (2014) Genesis of shale geological formations and hydrocarbon extraction: impact on environment and human health.[112] Compiler Algimantas Grigelis. (link) The report acknowledges potential risks, but notes that technological means available used for shale gas are technically safe, if requirements are met. The report recommends strengthened regulatory controls.

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[108] http://www.rijksoverheid.nl/ministeries/ez/documenten-en-publicaties/kamerstukken/2013/08/26/brief-aan-de-tweede-kamer-schaliegas-resultaten-onderzoek-en-verdere-voortgang.html (In Dutch)
[109] http://www.irgc.org/wp-content/uploads/2013/12/IRGC-Report-Unconventional-Gas-Development-2013.pdf
[110] http://www.gov.scot/Resource/0045/00456579.pdf.
[111] http://www.umweltbundesamt.de/publikationen/environmental-impacts-of-fracking-related-to
[112] http://skalunudujos.lt/wp-content/uploads/2014-12-02_Genesis_of_shale_geological-formations_LMA-website.pdf

14. Swiss Academies of Arts and Sciences (2014) Eine Technik im Fokus: Fracking – Potenziale, Chancen und Risiken (A technique in focus: Fracking - potentials, opportunities and risks). The report discusses hydraulic fracturing and notes that the creation of a legislative framework or guidelines for licensing is a priority. One of the main concerns of the authors is the high space requirements in the relatively small country like Switzerland (link).
15. European Union. EASAC Council. (2014).
    This EASAC analysis provides no basis for a ban on shale gas exploration or extraction using hydraulic fracturing on scientific and technical grounds, although EASAC supports calls for effective regulations in the health, safety and environment fields highlighted by other science and engineering academies and in this statement.[113] (link)
16. Polish Academy of Sciences (2014) Description of the shale gas formations: reserves and characteristics of problems related to its exploitation. The Presidium of Polish Academy of Sciences. The existing regulations in Poland and Europe concerning environmental protection are effective, but also restrictive. The report recommends effective oversight of operations. (link)
17. Polish Geological Survey (2014). The development of shale gas in Poland and its prospects in the Czech Republic - analysis and recommendations. (link). "The results of environmental tests are the basis of the position of the Polish government, which believes that existing EU legislation provides sufficient protection of the environment during the exploration and production of shale gas and does not require modification." "The moratorium (in the Czech Republic) itself can be seen as a populist, poorly articulated response to the need to change legislation that, in fact, need serious reform."
18. Acatech. German Academy of Science and Engineering (2015). Hydraulic Fracturing, A technology under discussion. (link) The German Academy found that "A general ban on hydraulic fracturing cannot be justified on the basis of scientific and technical facts. The use of the technology, however, should follow strict safety standards, be clearly regulated and are comprehensively monitored."
19. German Institute for Geosciences and Natural Resources (BGR) started the project NiKo in 2011, in close collaboration with the United States Geological Survey USGS. The project will run until 2015. NiKo investigates the shale gas potential for Germany, with a first report published in May 2012 (in German). The conclusion of the study on environmental concerns is this: "From a geoscientific point of view, environmentally-friendly application of the technology is possible, as long as the law is observed, the necessary technical measures are taken and local baseline studies and pilot surveys are carried out. Hydraulic fracturing is compatible with the protection of freshwater reservoirs." (link)

17.3. Other studies of interest.

1. German Hydrofracking Risk Assessment – Panel of Experts. (2012) Study concerning the safety and environmental compatibility of hydrofracking for natural gas production from unconventional reservoirs. The analyses focuses on worst-case scenarios - The results of this study show that fears that toxic substances will flow upwards into usable groundwater are unjustified, provided that specific underground related requirements are adhered to. However, leaks and accidents in wells and during the transport and storage of fluids containing hazardous substances are a very real possibility, and fears of such events are justified. (link)

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[113] http://www.leopoldina.org/uploads/tx_leopublication/2014_EASAC_ShaleGasExtraction_STATEMENT.pdf

2. Center for European Policy Analysis (2014). Energy Security in Central and Eastern Europe Science-Based Decisions and U.S. Best Practices in Hydraulic Fracturing.
   The Authors summarise "Almost 70 years worth of U.S. experience in hydraulic fracturing can attest to its relative safety as a method of hydrocarbon extraction. Many claims about the environmental dangers from fracking cannot be substantiated by scientific fact" (link)

17.4. Scientific and Technical reports (Industry).

3. Society Of Petroleum Engineers (2012) Paper 152596 Hydraulic Fracturing 101. What Every Representative, Environmentalist, Reporter, Investor, University Researcher, Neighbour and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells. The paper introduces Hydraulic Fracturing, and discusses risk and risk management. (link)