SHALE GAS EXTRACTION AND DEVELOPMENT

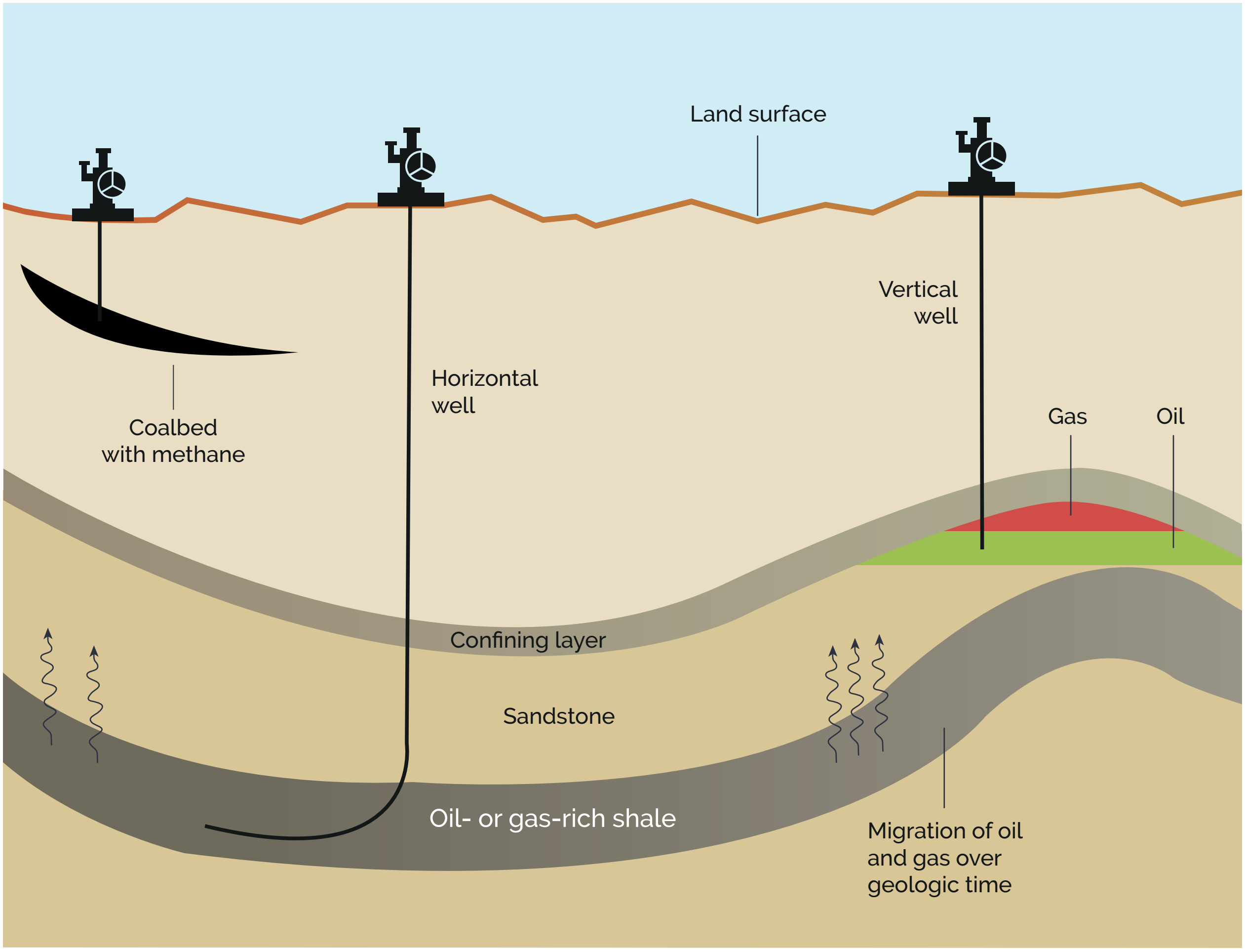
5

5.1 Differences between conventional and unconventional gas

5.1.1 Occurrence of conventional and unconventional gas

The terms 'conventional' and 'unconventional' gas are often misunderstood and have assumed different meanings in different material relating to the gas industry. For the purpose of this Inquiry, 'unconventional' gas is found in relatively impermeable source rocks, where the gas has been trapped where it was formed (**Figure 5.1**). This is different from 'conventional' gas, which has migrated from its original source rocks into more porous, permeable rocks and has then been trapped under a seal of impermeable rocks. Unconventional gas includes CSG, which is found in coal seams, shale gas (found in shale rocks), and tight gas (found in sandstone).

Figure 5.1: Schematic showing different types of petroleum accumulations and development. Source: Modified from US Environmental Protection Agency.



Irrespective of where it occurs, natural gas is composed mainly of methane - up to 98% - with varying amounts of other trace gases such as ethane, propane, butane and other hydrocarbons. From a consumer's perspective, unconventional gas is effectively identical to conventional gas.

5.1.2 Extraction of conventional and unconventional gas

Conventional gas can typically be developed with a limited number of wells, due to the accumulation of the hydrocarbons in a confined area with well-connected pore spaces within the rock trapping the gas that enable effective drainage from strategically placed wells. The gas will generally flow to the surface under its own pressure driven by a water table (or aquifer) underneath a pressurised gas cap or an impermeable barrier.

By contrast, the shales that hold unconventional gas have much lower porosity (that is, the void spaces between the grains that make up the rock are very small) and much lower permeability (that is, the interconnectedness of the pore spaces to allow the gas to move through the rock is very low). In order to extract shale gas, it is necessary to increase the level of porosity and permeability. This is termed 'artificial stimulation' and generally involves hydraulic fracturing.[1]

There are differences in the extraction techniques for the different forms of unconventional gas:

- **coal seams:** are typically found relatively close to the surface (usually no more than 1,000 metres deep). The extraction of CSG does not always require hydraulic fracturing (currently around 8% of wells in Queensland), but does require the removal of water from the coal to unlock the gas ('dewatering'). Large amounts of water are produced (known as 'produced water'), which must often be treated to remove excess salt prior to disposal;
- **shale gas source rocks:** occur deeper at between 1,500 and 4,000 m underground. Extraction of shale always needs hydraulic fracturing, but does not need to remove large quantities of existing groundwater to unlock the gas. Only a portion of the water that is used in the hydraulic fracturing process is returned to the surface. This returned water ('flowback water') can often be reused for subsequent hydraulic fracturing operations, or must be treated and disposed of; and
- **tight gas source rocks:** usually occur at similar depths to shale gas source rocks. These rocks have such low permeability that hydraulic fracturing is always necessary to allow the trapped gas to be liberated. Like shale gas, the returned water (flowback water) can often be reused for subsequent hydraulic fracturing operations, or must be treated and disposed of.

5.2 Shale gas development

5.2.1 History

Hydraulic fracturing was developed more than 100 years ago, but its combination with horizontal drilling in the 1990s began a shale gas revolution in the US that has since transformed the energy market in North America and significantly affected world trade in gas and oil. The shale gas industry has since developed in countries such as Canada, Europe and the UK, and other countries such as China, Russia and Argentina are evaluating its potential. The current world ranking among countries of recoverable shale gas resource is: China, Argentina, Algeria, US, Canada, Mexico, Australia, South Africa, Russia and Brazil, although recent NT discoveries in the Beetaloo Sub-basin are likely to increase Australia's global ranking of gas resources from seventh to sixth (see Chapter 6).

Although shale gas resources have been known to exist in Australia for many years, shale gas development is still in its infancy. In 2012, Santos' Moomba-191 well in the Cooper Basin in SA became the first commercially producing unconventional gas (tight gas) well in Australia, following almost 10 years of exploration for unconventional gas in that basin. None of the Northern Territory's considerable shale gas resources have yet been commercially developed (Chapter 6).

5.2.2 Stages of exploration and development

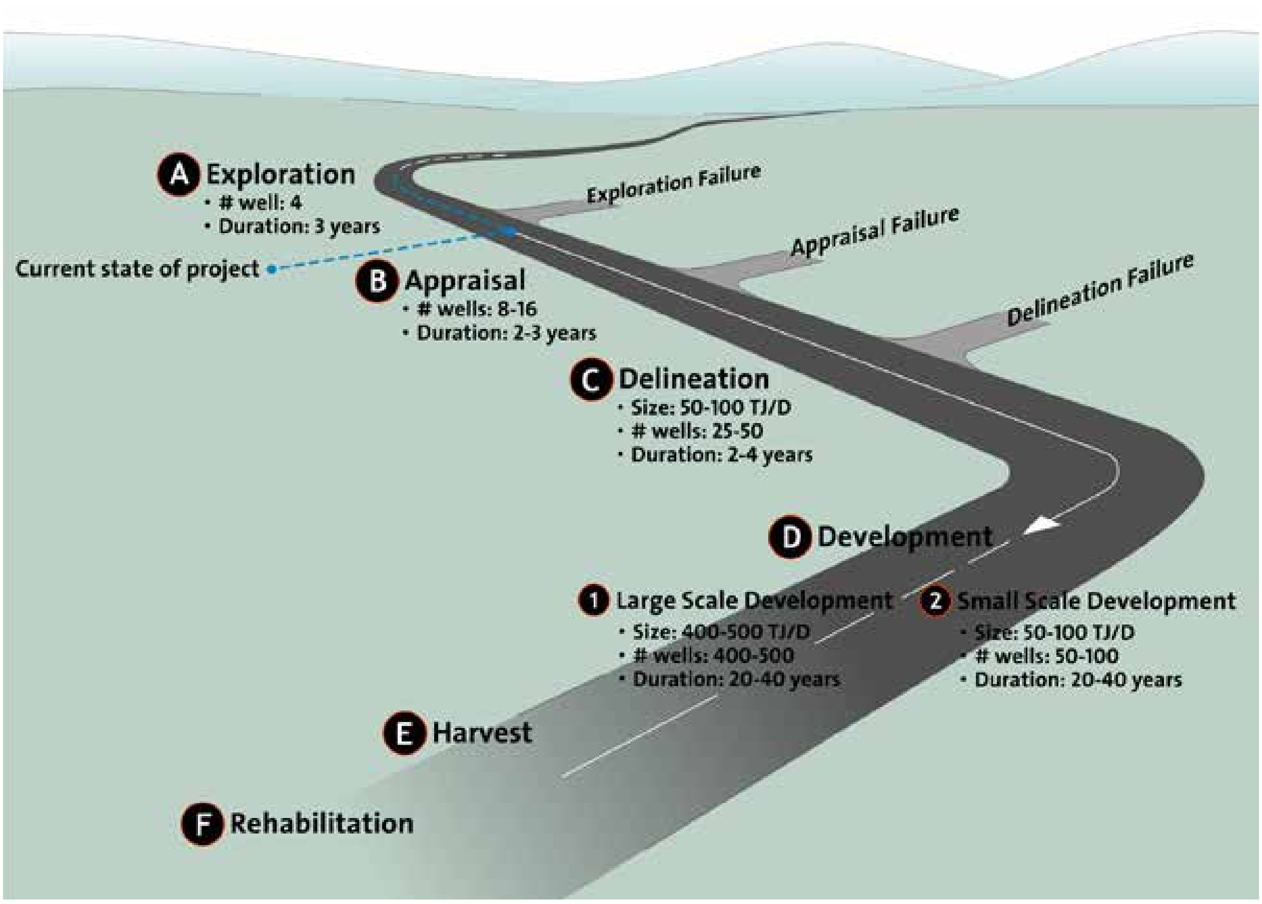
The commercial production of shale gas is the culmination of a process spanning several years, and includes exploration, drilling, hydraulic fracturing, testing and economic analysis (**Figure 5.2**).[2] The different stages of shale gas development are:

- **stage 1:** identification of the gas resource - negotiating land access agreements, securing seismic survey and drilling permits, and undertaking initial geological, geophysical and geochemical surveys;
- **stage 2:** early evaluation drilling - seismic mapping of the extent of gas-bearing formation and other geological features such as faults, initial vertical drilling to evaluate shale gas resource properties, and collection of core samples;

1 King 2012.
2 King 2012; Origin Energy Ltd, submission 153 (**Origin submission 153**), p 38.

- **stage 3:** pilot project drilling - drilling of initial horizontal wells to determine reservoir properties and to help optimise operational techniques, and initial production testing;
- **stage 4:** pilot production testing drilling - drilling of multiple horizontal wells from a small number of single pads, full optimisation of operational techniques including drilling and multi-stage hydraulic fracturing, pilot production testing, and planning of pipeline corridors for field development;
- **stage 5:** commercial development - following a commercial decision to proceed, and government approvals for construction of gas plants, pipelines and other infrastructure, drilling and fracturing of a network of production wells. During drilling and hydraulic fracturing of the wells there will be a concentration of heavy equipment on site, along with large stockpiles of drilling supplies and hydraulic fracturing chemicals. This can involve thousands of truck movements per well site over several months, with directional drilling occurring over several months, and hydraulic fracturing usually taking less than one month.[3] After the completion of drilling and hydraulic fracturing, all heavy equipment is removed and permanent surface infrastructure is constructed, including a cement well pad, a wellhead, gas pipeline, and fencing to keep livestock and other fauna away from the well. The final footprint of the wells and surface facilities is much smaller than the original drilling footprint (see Section 8.3); and
- **final stage:** 'decommissioning' or 'abandonment'. This involves removal of the wellhead, plugging the steel casing with cement and steel, the removal of all production equipment, production waste, pipelines and other infrastructure; and the rehabilitation of all cleared areas.

Figure 5.2: Schematic representation of a project phasing in gas developments, with specific estimates of activity for a notional development in the Beetaloo. Source: Origin.[4]



3 ACOLA Report.
4 Origin Submission 153, p 38.

5.3 Extraction of onshore shale gas

5.3.1 Overview

As stated above, shale gas reservoirs are typically located at depths of 1,500 to 4,000 m below the ground surface. Because of their very low permeability, shales need to be split (fractured) before the gas (mainly methane) can flow to the surface.

The drilling and hydraulic fracturing technologies used in extraction of onshore shale gas have evolved considerably from those used for the conventional petroleum resources over the past two decades.[5] Drilling for shale gas now typically involves the drilling of multiple wells from a single well pad with horizontal extensions ('laterals') increasing the exposure to the target shale formation.[6] In order to produce shale gas, multiple intervals, or sections of hydraulic fracturing, are placed along the horizontal section of the well. The most common hydraulic fracture designs for shale gas wells in the US use water-based hydraulic fracturing fluids, which are pumped into the well at a high pressure.[7] The adoption of these technologies has led to a rapid growth of shale gas and oil production in the US.[8]

The very nature of the extraction process, which involves drilling to great depths and the injection of chemical mixtures at high pressure through the well system, is of paramount concern to the community. The maintenance of well integrity throughout the operational life of a well and beyond is therefore of crucial importance.

For this reason, the Panel commissioned CSIRO to produce a comprehensive review of this topic (the report is located at Appendix 14). The Panel has drawn heavily on CSIRO's report for producing the well integrity section of this Chapter. However, all conclusions and recommendations are those of the Panel.

5.3.2 Well life cycle

All wells follow a similar life cycle, with some variations in their design and operational aspects depending upon their purpose and the local geology. The well life cycle phases are described below.

5.3.2.1 Design phase

The detailed design phase includes consideration of the overall well life cycle, including all future operations for the well, through to its eventual abandonment. A description of this type of approach to well design was provided by Origin in a submission to the Panel.[9] The design of the casing, cementing and completion are important considerations for long-term well integrity.

The well design is based on a detailed analysis of the following information and definitions:[10]

- well design and specification of materials and equipment (such as casing, cement, completion);
- data acquisition program, including well logging, sample collection and well testing;
- well stimulation activities;
- well barriers to manage well integrity;
- operating procedures, including risk management and well integrity management; and
- plans for final abandonment.

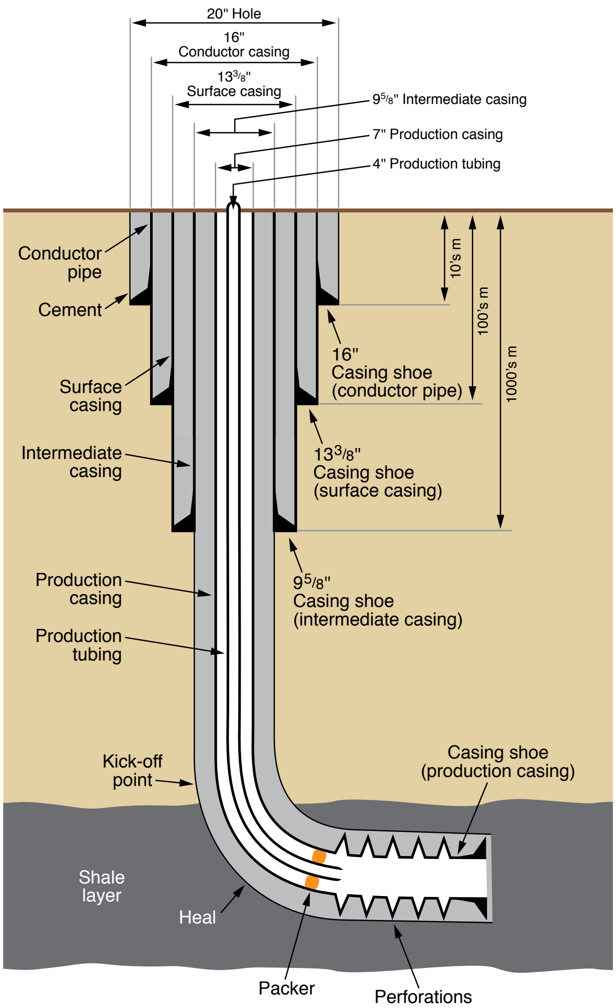
The 'casing' is the steel pipe that provides a pressure tight conduit between the shale gas resource and the surface.[11] It is a highly engineered product that must cope with anticipated wellbore conditions, including the very high pressures applied during hydraulic fracturing. International standards cover the manufacture, testing, engineering specification, mechanical properties and performance of the casing.[12] The casing is designed to prevent the unintended

5 Golden and Wiseman 2015, pp 968-974.
6 Cook et al. 2013, pp 54-56.
7 Gallegos et al. 2015.
8 Cook et al. 2013.
9 Origin submission 153, pp 55-60.
10 ISO 2017.
11 Hossain and Al-Majed 2015, pp 433-501.
12 ISO 2014.

flow of drilling and hydraulic fracturing fluids out of the well, to keep the well open through weak or broken rock layers, and to prevent formation fluids from entering the well and from moving between layers of rock through the well.

Well drilling occurs in stages, with each stage cased before further drilling using a smaller diameter drill bit. **Figure 5.3** shows the general layout of casing used in shale gas wells, demonstrating that the diameter of the well decreases with depth, as successive casings are placed inside the previous casing strings. The design of casing for a well needs to take into account the depths of layers of rock or aquifers that must be isolated from each other, the corrosive nature of fluids or gases (such as hydrogen sulfide or carbon dioxide) that may be encountered, the stresses that the casing will be subjected to, and the operational requirements of the well.

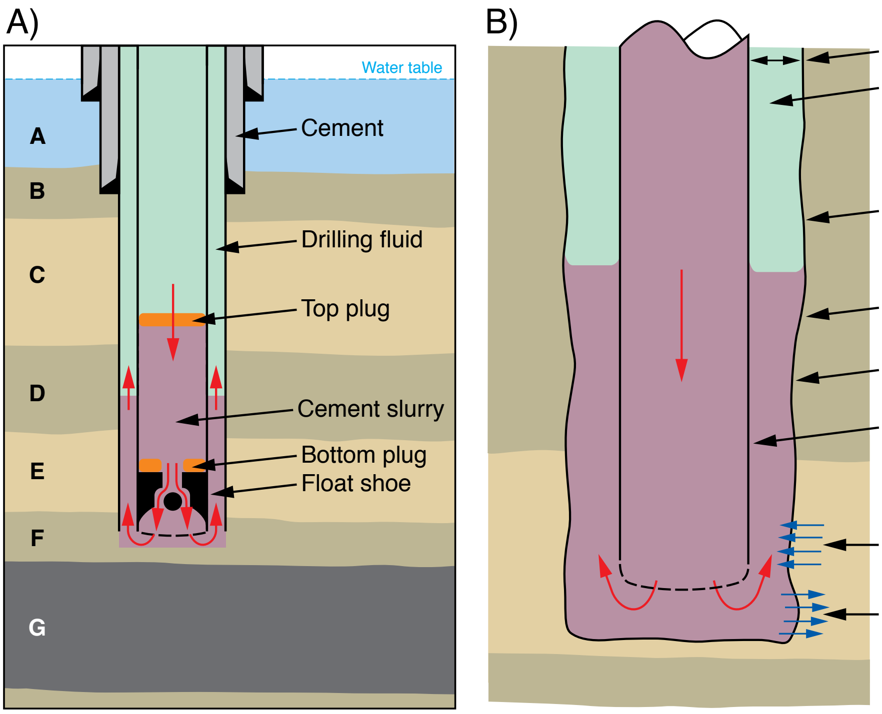
Figure 5.3: General layout of casing in a shale gas well. Not to scale (width is significantly exaggerated). Source: CSIRO[13]



Cementing is essential for two reasons. Firstly, to provide strength to the well, and secondly, to provide a seal between the casing and the surrounding rock so that gas and fluids cannot flow from the shale formation (and other intersecting formations) to the surface.[14] During the cementing process, a cement slurry is pumped down the centre of the well and flows up the annulus (the gap between the rock formation and the most recently placed casing) (**Figure 5.4**). Well cements are designed, tested and prepared using established procedures to meet relevant specifications and have negligible permeability to formation fluids when cured.[15] The casing and cement work together in an integral system that is critical to well integrity. The stability and longevity of cements is covered in Section 5.4.2.4.

13 CSIRO 2017, at Appendix 14 of this Report.
14 Taoutaou 2010.
15 ISO 2009.

Figure 5.4: The process for cementing casing into a well. The cement is pumped down the centre of the well and returns up the outside of the well (A). The well requirements for an effective cementing are shown in (B). Not to scale. Source: Modified from Smith.[16]



The design of wells, the specification of materials and equipment used in their construction, and well operations are covered by a large number of standards. As at June 2016, the International Association of Oil and Gas Producers listed more than 150 primary standards related to well construction and well operations.[17] These standards are mandatory in some, but not all, jurisdictions. Most of them relate to quality control for operations and the provision of services and materials to the industry.

5.3.2.2 Construction phase

Well construction involves drilling, cementing, and hydraulic fracturing in accordance with the well design. Drilling fluids (drilling muds) are an essential component of drilling operations[18] because they provide cooling and lubrication to the drill bit and drill string and lift drill cuttings from the well.

Casing is installed and cemented in place in a number of stages, as shown in **Figure 5.3**. Initially, a large diameter surface casing is set sufficiently deep to protect surface aquifers and is fully cemented in the ground. Once a well is drilled to the depth where a casing string is required, a steel casing string is run into the borehole and cemented (**Figures 5.3 and 5.4**) The cement fills and seals the annulus between the casing strings, or between the casing string and the formation rock. This process is repeated until the well construction is complete. The term 'sheath' is used to describe this encasing layer of cement.

At each stage the well is prepared (cleaned by the circulation of drilling fluid) then cement is pumped down the centre of the well so that it flows around and up the annulus between the casing and the surrounding rock. The well integrity provided by the cement is not only dependent on the cement slurry design but also on a number of other aspects of the well cementing process, such as the cleaning and preparation of the wellbore and the condition and centralisation of the casing in the wellbore.[19]

Importantly, during drilling and cementing, testing of the well's integrity is undertaken.[20] For example, pressurising the well to verify that it can hold the maximum pressures that it may

16 Smith 1990.
17 IOGP 2016.
18 IOGP 2016, pp 73-139.
19 CSIRO 2017, p 12.
20 Standards Norway 2013.

be exposed to over its life, including the initial hydraulic fracturing operation. This will test the integrity of both the well casing and cement.[21] Additionally, there are a number of downhole sensor and logging tools that can be used to measure the state of the casing and the integrity of the bond between the casing, cement and rock.[22]

The final activity in the construction phase is the 'completion' of the well, that is, preparing it for the production of gas.[23] Completion involves the installation of hardware in the well and on the surface to allow the safe and efficient production of gas from the well at a controlled rate.

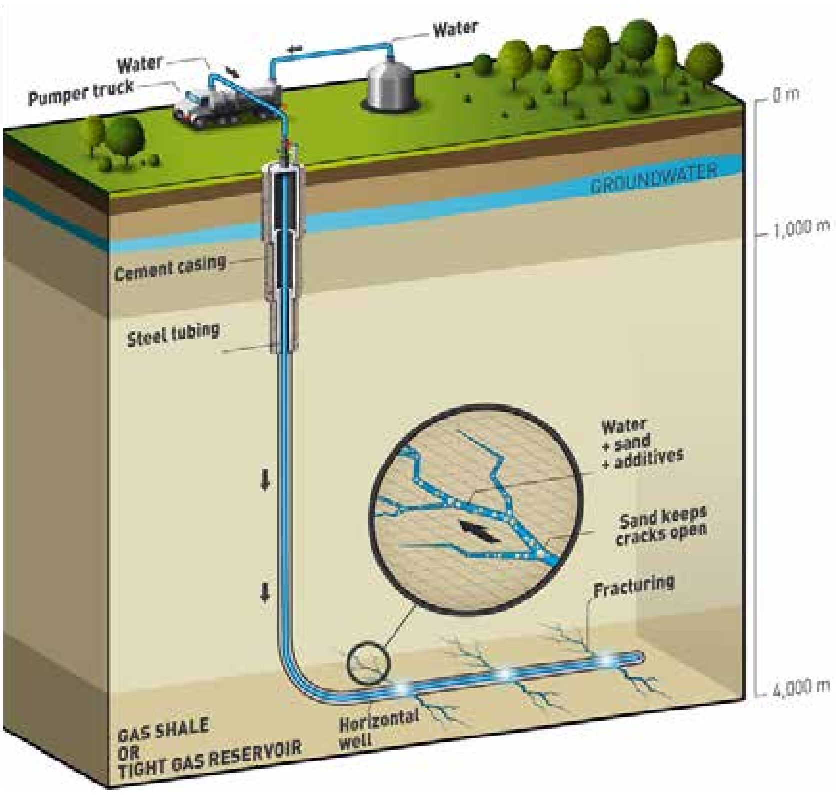
5.3.2.3 Hydraulic fracturing

Hydraulic fracturing is a stimulation technique used to increase the production of oil and gas from unconventional reservoirs, such as shales, by the injection of a hydraulic fracturing fluid at high pressure into a cased wellbore (**Figure 5.5**). Hydraulic fracturing is usually conducted over a number of intervals along the production zone of the well, called 'hydraulic fracture stages' (**Figure 5.6**).

Most hydraulic fracturing treatments in shale gas wells take place in the relatively long (up to several kilometres) horizontal or nearly horizontal section of the well (lateral). The number of fracture stages in a single well has increased over time in US unconventional gas fields. For example, in 2009, 10-12 fracturing stages would have been typical, with a spacing of around 200 m. While in 2017, it is common for 40-100 fracture stages in a single lateral, with a spacing of around 15-30 m between segments that are being fractured.[24]

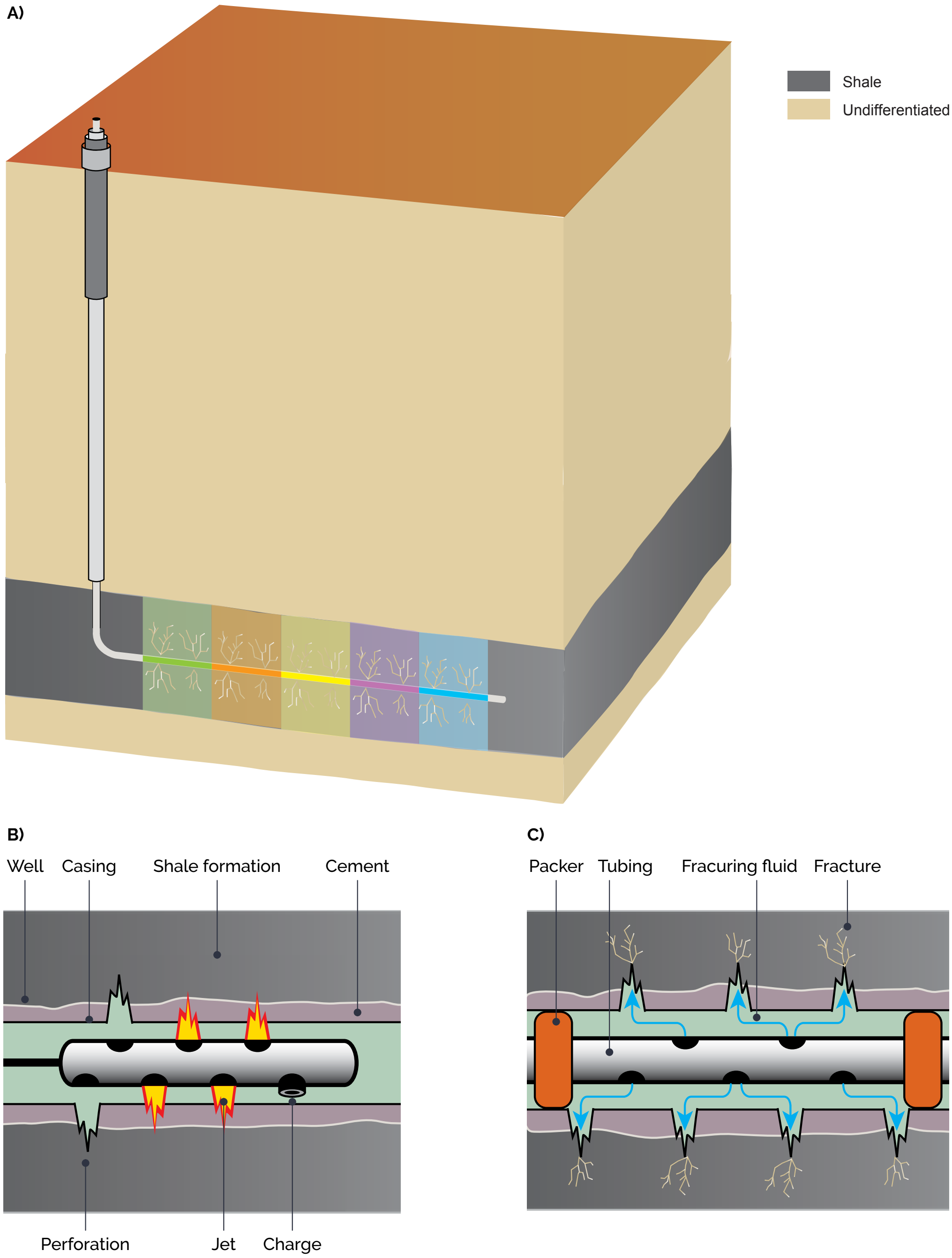
The hydraulic fracturing fluid is predominantly a mixture of water, proppant (commonly sand, or ceramics where formation pressures are high), and small percentage of chemical additives (typically less than 1%).[25]

Figure 5.5: Schematic diagram of shale gas extraction process showing hydraulic fracturing.
Source: Modified from Total S.A.



21 For example, see Origin submission 153, pp 63-66.
22 Jeffrey et al 2017, Section 3.5.
23 Hossain and Al-Majed 2015.
24 CSIRO 2017, p 15.
25 US EPA Report, pp 3-21.

Figure 5.6: Hydraulic fracture stages. Source: CSIRO[26]



Hydraulic fracturing is typically conducted in stages. Each coloured zone in (A) shows a different stage. For each stage, the casing must be perforated to allow the hydraulic fracturing fluid to access the shale formation (B). Hydraulic fracturing is then conducted in each stage within a short section of the well that has been isolated, in this case using packers (C). Not to scale.

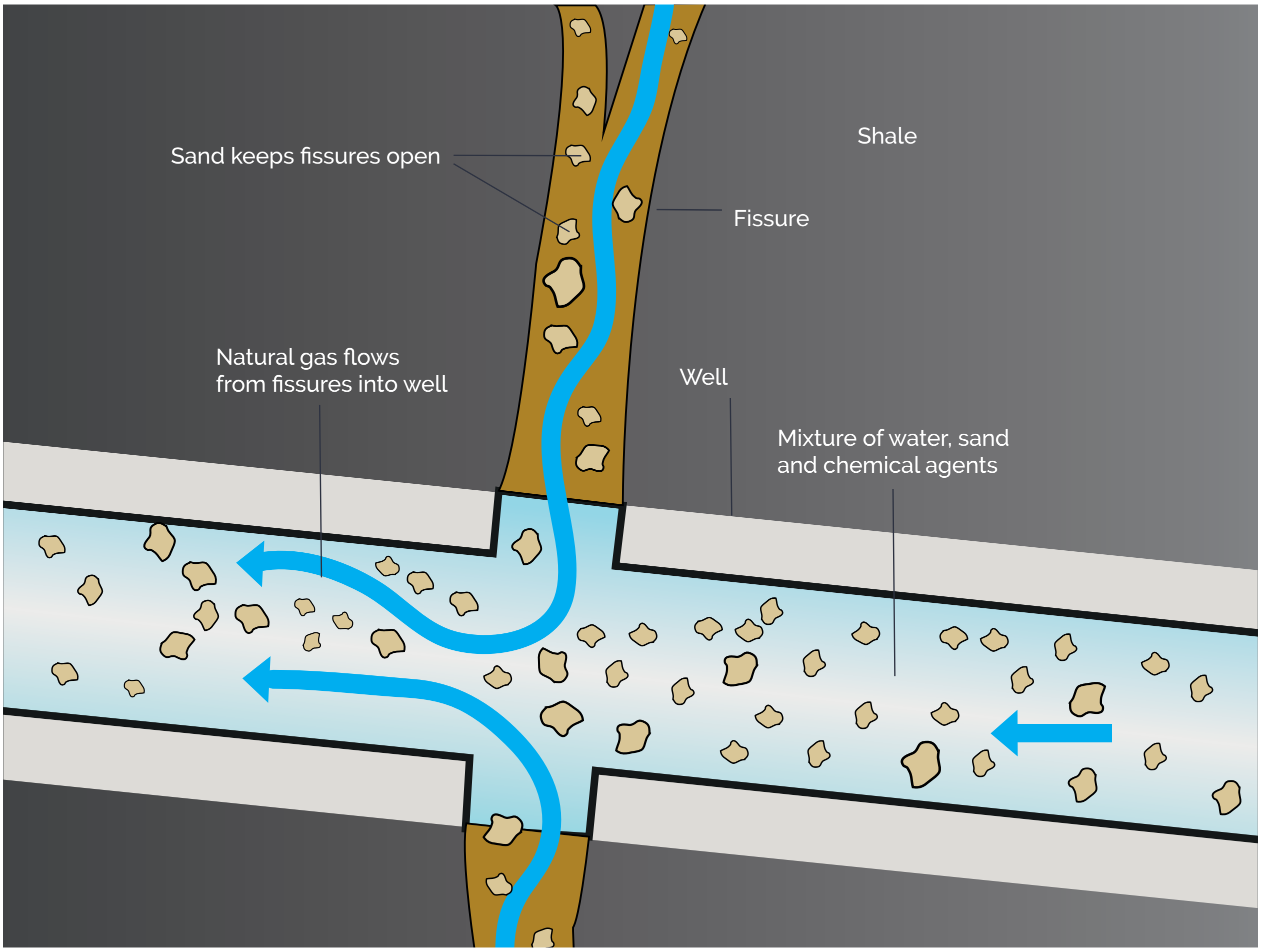
The lateral in the zone to be fractured is perforated using shaped charges and isolated using mechanical plugs or other devices before the hydraulic fracturing fluid is injected into the isolated wellbore zone. As the hydraulic fracturing fluid is contained within the isolated wellbore zone, the pressure builds up until it exceeds a threshold known as the 'breakdown pressure'. Once the hydraulic fracture fluid pressure exceeds the breakdown pressure, it fractures the rock. The direction in which the hydraulic fracture propagates depends on the orientation of in situ stress in the rock, with growth mainly occurring in a direction perpendicular to the minimal principal stress.

26 CSIRO 2017.

Once the hydraulic fracture has been initiated, further propagation is controlled by the fluid flow. Some of the hydraulic fracturing fluid drives hydraulic fracture growth, with the rest being injected or lost by absorption into the formation (a process known as 'leak-off'). The surface area of the hydraulic fracture increases as the fracture grows, thereby increasing the fluid loss into the formation. The hydraulic fracturing fluid injection rate is calculated to propagate hydraulic fractures to the desired size given the expected fluid loss into the formation.

"Proppant" is added to the hydraulic fracturing fluid to hold the fractures open at the end of the treatment. At the start of the stimulation, the hydraulic fracturing fluid is injected without any proppant to initially open a fracture wide enough to allow the proppant to travel along the hydraulic fracture. The wellbore is finally flushed to remove any residual proppant, leaving behind a proppant-filled fracture that acts as a conductive channel through which gas can flow into the wellbore (**Figure 5.7**).

Figure 5.7: Proppant in action. Source: Modified from Granberg.[27]



After hydraulic fracturing is complete, a portion of the hydraulic fracturing fluid, or flowback, will flow out of the wellbore and return to the surface (typically 10-30% of the initial hydraulic fluid).[28] The composition, collection, treatment and reuse of this flowback fluid is covered in Sections 5.7, 5.8 and Chapter 7 (Section 7.6).

5.3.2.4 Operational or production phase

Most shale gas wells are designed to keep producing hydrocarbons for decades. The main activities during production are the monitoring of the well's integrity and performance, and its maintenance. Wireline logging[29] is generally the only means of checking the integrity of

27 Granberg 2008.
28 US EPA Report.
29 This is a technique whereby logging instruments are lowered down the well to measure the integrity of the casing, cement lining, or the geological formations: Jeffrey et al. 2017, Section 3.5.

casing and cement down a well. Abnormal pressures in the annulus between casing strings and changes in production rates can indicate integrity issues.[30]

In some cases, it is necessary to re-enter a well (called a 'workover') to perform maintenance, repairs or replacement of components, for surveillance, or to increase productivity.[31] Such interventions can be critical to maintaining well integrity, and there are a range of technologies that can be applied to repair the casing and cement if integrity issues are detected.[32] Wells may also need to be hydraulically re-fractured to extend their production lifetime.

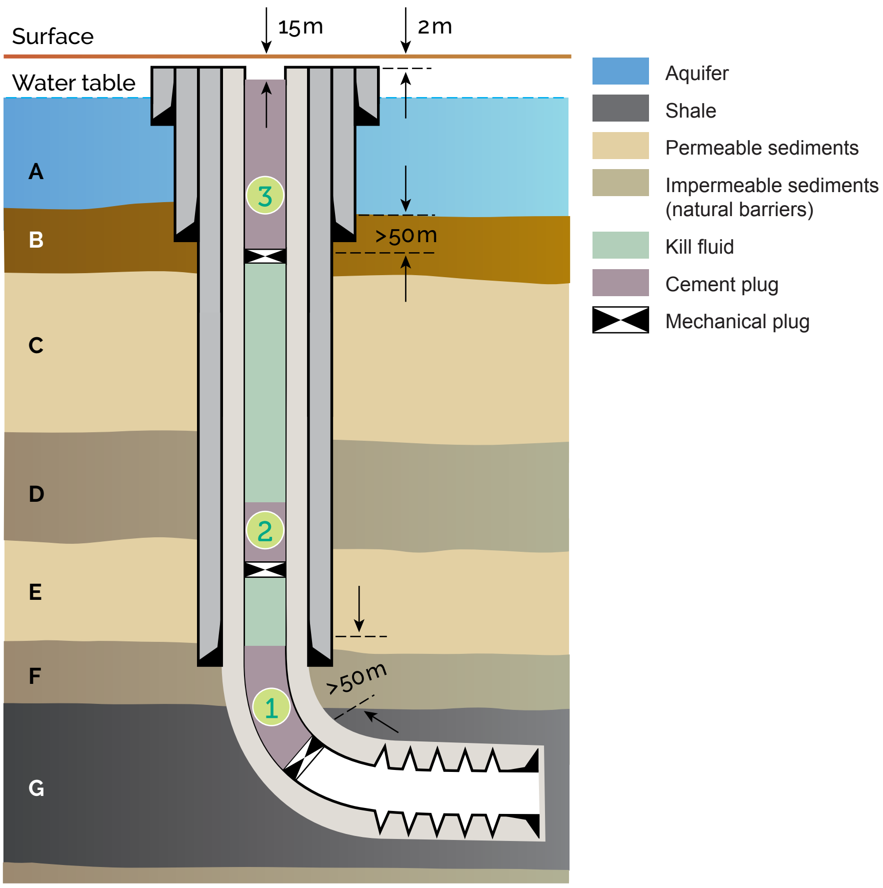
5.3.2.5 Well decommissioning and abandonment

Abandonment, that is, where the wells are decommissioned and 'plugged and abandoned', is the final phase in the well life cycle. The goal of plugging and abandoning a well is to ensure well integrity in perpetuity, effectively re-establishing the natural barriers formed by impermeable rock layers drilled through to reach the resource.[33] The aims of abandonment are to: [34]

- prevent release of formation fluids, or well fluids, to the environment, including aquifers;
- prevent the flow of groundwater or hydrocarbons between different layers of rock; and
- isolate any hazardous materials left in the well.

A schematic of an abandoned well is shown in **Figure 5.8**. The plugs typically consist of cement with a mechanical plug. To provide long-term integrity, the cement (or other barrier material) must not shrink, be able to withstand the stresses in the wellbore, be impermeable, be impervious to chemical attack from formation fluids and gases, be able to bond with steel casing and rock, and not cause damage to the casing.[35]

Figure 5.8: An abandoned well, showing the cement plugs that are placed in the well to prevent vertical flow of fluids. Not to scale. Source: CSIRO.[36]



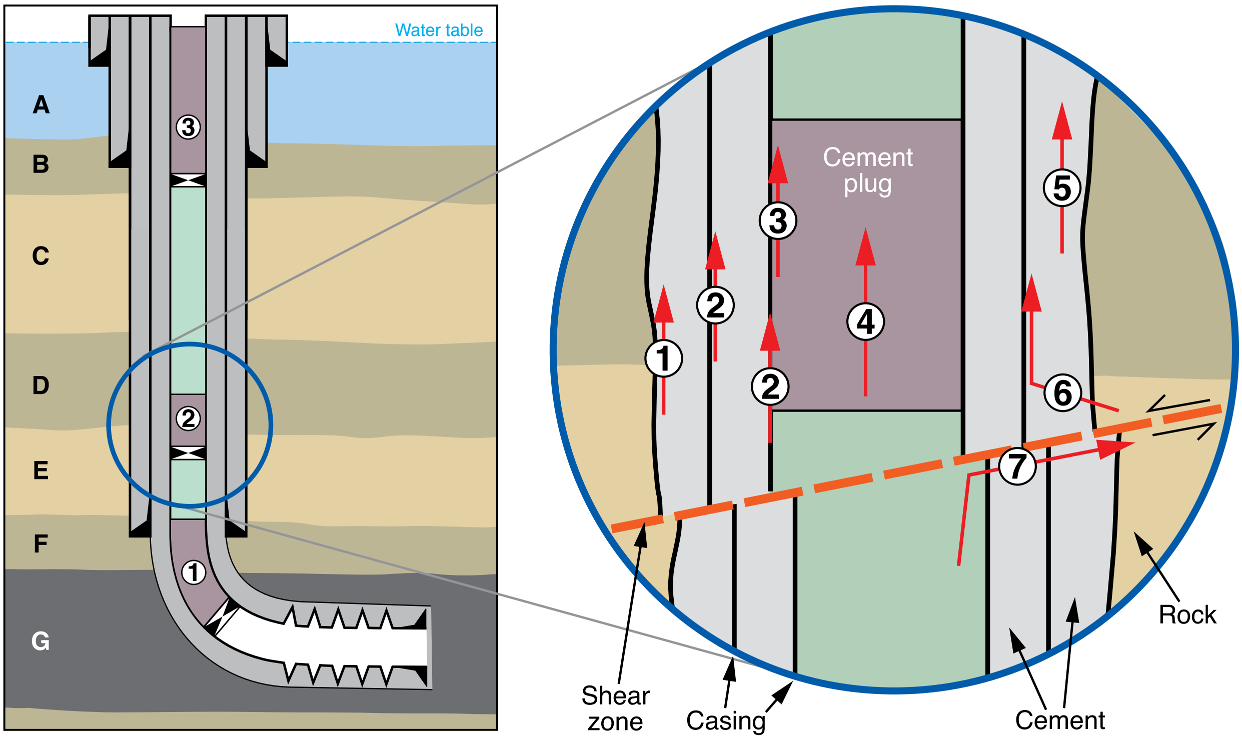
30 ISO 2017.
31 ISO 2017.
32 Durongwattana et al. 2012; Roth et al. 2008; Ansari et al. 2017.
33 Standards Norway 2013; Kiran et al. 2017.
34 Standards Norway 2013; Kiran et al. 2017.
35 Standards Norway 2013, p 96.
36 CSIRO 2017.

For a leak to occur in an abandoned well, whether the leak is to the surface or to the subsurface between different geological formations, three elements must exist:[37]

- there must be a source formation where hydrocarbons or other fluids exist in the pore space;
- there must be a driving force (due to a the difference in pressure, temperature, salinity or buoyancy) between the source formation and surface in the case of a leakage to surface, or between different geological formations in the case of a subsurface flow; and
- there must be a leakage pathway between the source formation and the surface, or between different geological formations.

Figure 5.9 shows a schematic of potential leakage pathways along an abandoned well.

Figure 5.9: Routes for fluid leakage in a cemented wellbore. Source: Modified from Davies et al.[38]



Path 1 – between cement and surrounding rock formations;
Path 2 – between casing and surrounding cement;
Path 3 – between cement plug and casing or production tubing;
Path 4 – through cement plug;
Path 5 – through the cement between casing and rock formation;
Path 6 – across the cement outside the casing and then between this cement and the casing; and
Path 7 – along a shear through a wellbore.

In common with operating wells, leakage or failure of abandoned wells could occur via poorly cemented casing/hole annuli, faults in the interface between cement and the formation rock and casing failure.[39] Additionally, for abandoned wells, the interface between cement plugs and casing has been identified as a preferential pathway for fluid flow.[40] Migration of fluid can also occur through fractures, channels, and the pore space in the cement sheath. In the latter case, fluid flow will only occur when the cement sheath is degraded or does not form properly during the cementing process.[41] For shale gas wells abandoned using current practices it is highly unlikely that if any of these leakage pathways were to develop they would allow large fluid flow rates. The small cross-sectional areas and long vertical lengths of the pathways will limit flow.

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37 Watson 2004.
38 Davies et al.2014.
39 Watson and Bachu 2009.
40 Gasda et al. 2004.
41 Zhang and Bachu 2011.

The low permeability of shale gas formations is also a factor mitigating the potential for adverse impacts due to loss of well integrity post well abandonment. Pressures within the part of the reservoir accessed by the well will have been depleted by production, and the very low permeability of the shale will also act to prevent gas from other parts of the reservoir migrating to the well. Restoration of pore pressure in the reservoir is likely to be slow because of the low permeability preventing migration of any high pressure fluids from outside the reservoir, and the geological time scale of processes that might increase pressures from within the shale. But some gas will remain in the part of the reservoir accessed by the well, and its buoyancy will provide drive for upward flow should pathways be available.

The combination of small cross sectional areas, long vertical lengths of flow pathways and low driving pressure differentials means that overall, there is a low likelihood of substantial vertical movement of fluids post abandonment.

Well abandonment is a global issue, with estimates that around 30,000 wells globally will need to be plugged and abandoned over the next 15 years.[42] It is highly likely that well abandonment practices will experience innovation as the scale of abandonment activity increases globally in the context of increased scrutiny of environmental performance.

The Panel has found that there is a paucity of information available on the performance of abandoned onshore shale wells. Indeed, it appears to be only recently that specific attention has been paid to this issue by regulators. It was the subject of specific questions to expert consultants by the UK Royal Society and the Royal Academy of Engineering when it undertook an extensive review of shale gas extraction in the UK in 2012.[43] When asked about the long-term pressure behaviour of wells after they are plugged and abandoned, Halliburton, one of the largest service providers worldwide to the shale gas industry, responded that pressures are not monitored post abandonment and that there is no statistically based data available to indicate the percentage of wells that fail. Halliburton continued, *"based on reported MIT failure rates in active wells, the percentage should be very low and may be less than 1%."*[44]

Given the current moratorium in the NT, there is unlikely to be a substantial number of wells abandoned in the near future, which provides an opportunity to establish a long-term abandoned well program. This program should assess well abandonment options in the context of the NT's shale resources and consider:

- geological zones along the well which need to be isolated long term;
- reviewing and testing of the durability of cements and casing;
- the partial abandonment of some wells to allow long-term monitoring;
- evaluation of post-abandonment monitoring approaches;
- trials of novel abandonment methods and materials; and
- the costs of abandonment to assist in the calculation of security bonds.

In this context, it should be noted that 236 oil and gas wells have been drilled over the past 50 years in the NT.[45] Out of this total, 145 have been decommissioned (plugged and abandoned), 26 have been suspended for future data gathering or production, and 65 are currently producing from conventional reservoirs.[46] In the event that the moratorium is lifted, these existing decommissioned and suspended wells represent a starting point for implementation of an abandoned well assessment program.

In the NT the rules around well abandonment are set out in the *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (**Schedule**). A gas company must apply to the Minister for Primary Industry and Resources (**Minister for Resources**) to abandon a well, and the application must include a proposed abandonment program *"including the method by which the well will be made safe"*.[47] A well cannot be abandoned unless Ministerial approval is given. However, the Schedule does not make explicit what the Minister must consider when making a decision about a proposed abandonment program. Clause 329 of the Schedule prescribes how

42 Ouyang and Allen 2017.
43 Royal Society Report.
44 Halliburton Royal Society submission, pp 5-6.
45 Department of Primary Industry and Resources, submission 226 (**DPIR submission 226**), p 46.
46 DPIR submission 226, p 46.
47 Schedule, cl 328(5)(f).

a well must be abandoned, including that cement plugs are to be placed at certain intervals of the well.[48] It is not clear whether the terms of the approved abandonment program or the requirements of cl 329 will prevail in the event of an inconsistency. The Schedule also provides that, *"on completion of production activities and prior to the surrender of a production licence"*, all wells must be plugged and abandoned in accordance with an *"approved decommissioning plan"*.[49] Again, it is not clear how the approved abandonment program or the approved decommissioning plan, and the requirements of cl 329 interact. The Panel's concerns about the Schedule are discussed in further detail in Chapter 14.

Ensuring that world leading well abandonment practices are used and ongoing assessment of abandoned wells is undertaken represents a challenge for any regulator because it occurs at a time when the cash flows associated with the well have come to an end. The regulatory aim is to ensure that wells are abandoned safely, that there is funding available for ongoing monitoring, and that in the event that a well has not been abandoned properly, there is money available (from industry) to ensure problems can be remedied. In Chapter 14, the Panel recommends the establishment of an abandoned well levy to ensure that long-term funding is available to remedy wells that have not been abandoned properly and to implement the ongoing monitoring program recommended below. The Panel explores how to address this issue in Chapter 14.

Recommendation 5.1

That the Government mandate a code of practice setting out minimum requirements for the abandonment of onshore shale gas wells in the NT. The code must be enforceable and include a requirement that:

- ***wells undergo pressure and cement integrity tests prior to abandonment, with any identified defects to be repaired prior to releasing the well for decommissioning; and***
- ***testing must be conducted to confirm that the plugs have been properly set in the well.***

Recommendation 5.2

That the Government mandate a program for the ongoing monitoring of abandoned shale gas wells in the NT. The program must include the ongoing monitoring of water quality by bores installed adjacent to the well and the results of such monitoring to be published in real-time.

5.4 Well integrity

5.4.1 Overview

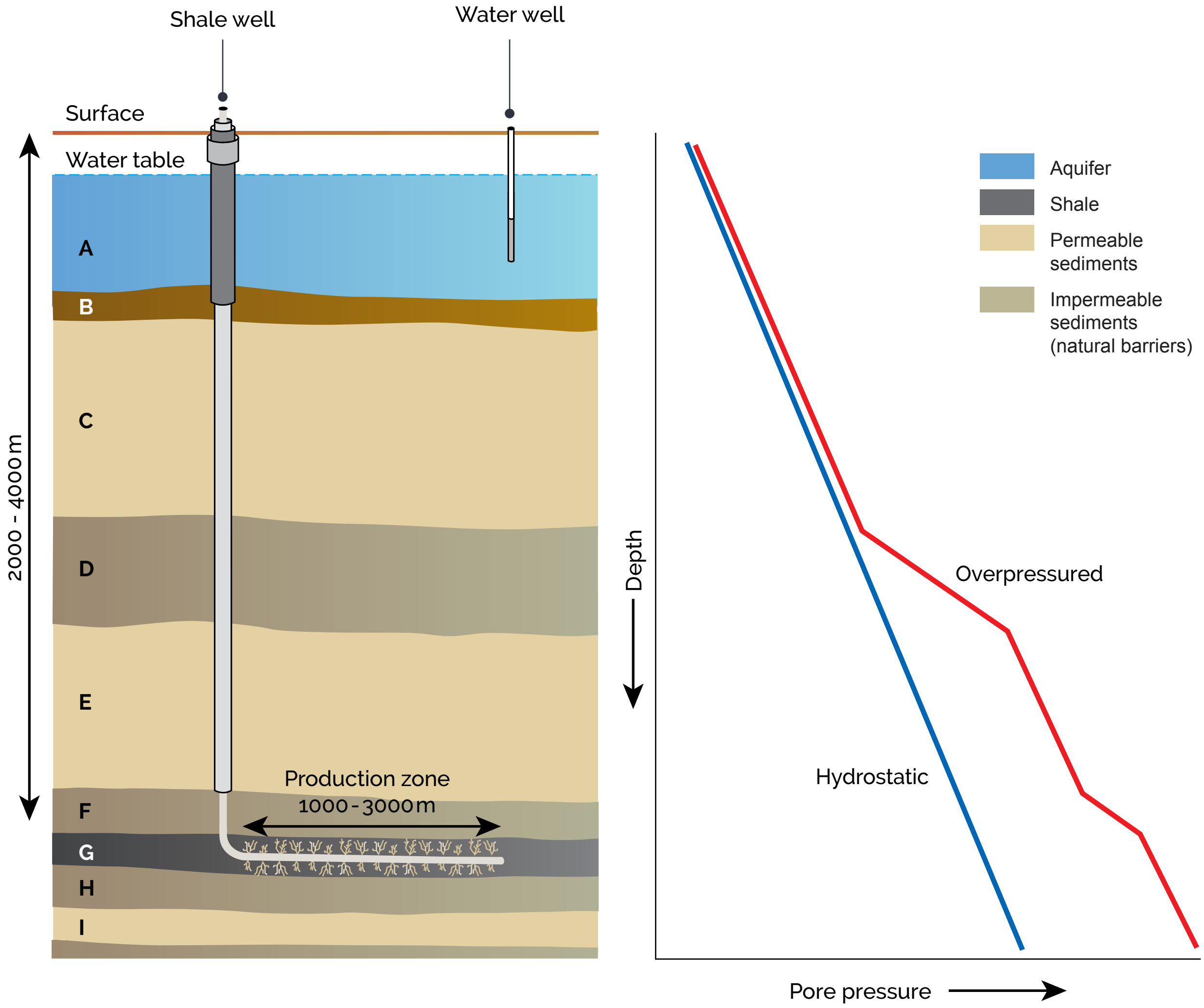
The integrity of onshore shale gas wells has been a key issue raised during the Panel's consultations throughout the NT (see Chapter 3). Well integrity is crucial for the safe operation of a well and to ensure that aquifers are not contaminated. The International Standards Organisation (**ISO**) defines well integrity as follows:

> *"Well integrity refers to maintaining full control of fluids (or gasses) within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment."*[50]

A knowledge of the processes that force fluids and gases to move to the surface from a shale layer is important to the understanding of how these may flow out of or into the well, or between layers of rock or to the surface via the well. **Figure 5.10** shows a simplified shale gas resource, consisting of the shale layer at the base, with overlying layers of various sedimentary rocks referred to as overburden. This overburden will include layers that can be classified as 'permeable', which allow fluid to flow through them, and 'impermeable', which form a barrier to fluid movement. Some of the permeable layers may be aquifers containing water that is used for agriculture or stock and domestic purposes, while others may contain salty water (brine). Hydrocarbons (oil and/or gas) may also be present in some rock layers.

48 Schedule, cl 329.
49 Schedule, cl 426.
50 ISO 2017.

Figure 5.10: Simplified shale gas resource. Source: CSIRO.[51]



Rock layers A-F are overburden that cover the shale resource (layer G). The graph shows the pore pressures in the rock, the gradient in blue is the hydrostatic gradient. The gradient in red shows the pore pressures in an overpressured scenario, with layer D and F trapping higher pressures below them. Not to scale.

The pressure of the fluids in the rock (pore pressure) increases with depth, and if this is greater than the hydrostatic pressure (the pressure that is equal to the weight of the column of fluid above it), the overpressure provides the driving force for the fluids to flow vertically. Methane, which is lighter than water, will move upwards through the rock unless there is an impermeable barrier in between.

When considering fluid movement, the presence of overpressures is a significant contributor to well integrity. High overpressures, which would drive vertical fluid movement, are not a common feature of shale resources, and the limited data collected in the Beetaloo Sub-basin indicates that this Sub-basin also has low overpressures.[52]

By contrast, the buoyancy and low viscosity of gas means that it is more likely to be able to move along these pathways. In addition, gas may also be present in shallower layers of rock as well as the target shale gas reservoir. Gas from any of these sources may move upwards along the well if a pathway is present. The rate at which fluid or gas can flow up a pathway will be limited by the aperture of the opening through which it flows. Where the annulus between well casing and the rock is cemented, the size of any opening will be limited.

The integrity of the well drilled through the rock barriers between the surface and the shale deposit is crucial to ensuring that a new pathway is not created through which gas or fluids can travel to the surface, or to drinking water aquifers.

51 CSIRO 2017.
52 Close et al. 2016.

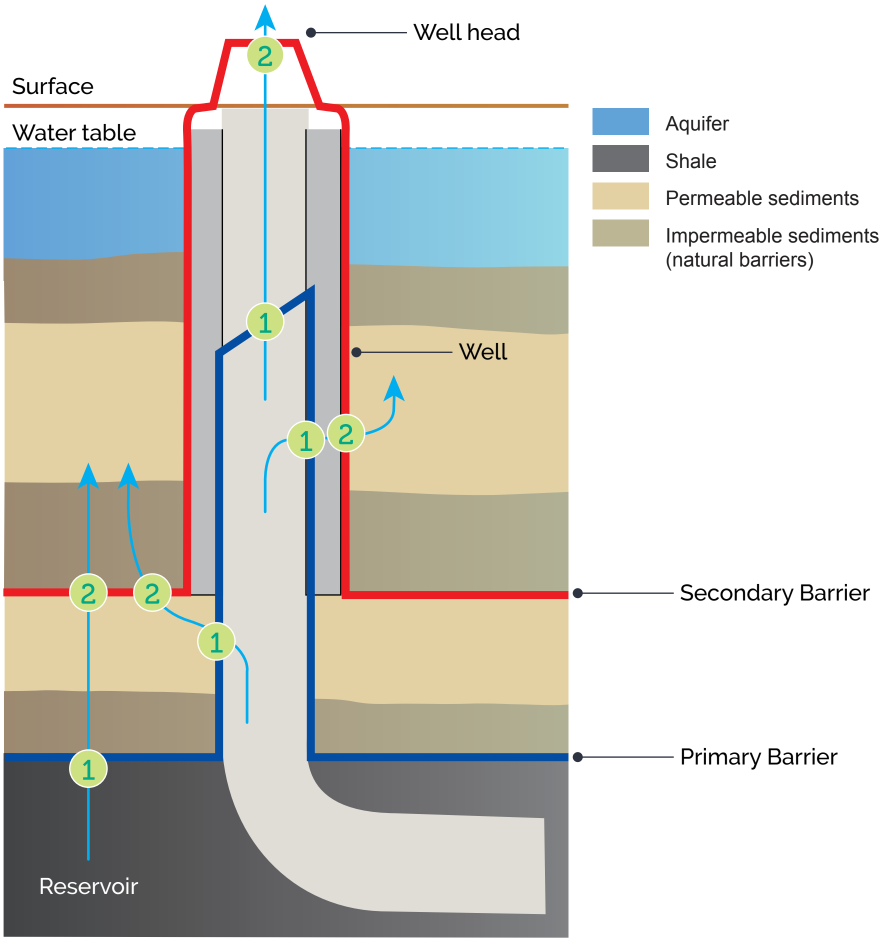
Discussed below are two broad categories of problems with well integrity:

- first, the unintended flow of fluids or gases between rock layers or to the surface along the outside of the well; and
- second, the unintended flow of drilling fluids or hydraulic fracturing fluid from inside the well into the surrounding rock, or from formation fluid or gas into the well.

5.4.2 Failure modes for well integrity

There are many elements that make up a well barrier system. All of these elements need to be tested to confirm well integrity. **Figure 5.11** shows examples of the (at least) two-barrier system that needs to be maintained throughout the well life cycle.

Figure 5.11: The two barrier concept showing the two barriers to various pathways for fluid flow out of the well. Source: CSIRO.[53]



Two types of well failure are generally distinguished:

- **well integrity failure:** all barriers have failed and a pathway exists for fluid to flow into or out of the well. In a dual barrier design, both barriers must fail for a well integrity failure to occur; and
- **well barrier failure:** one barrier has failed, but this does not result in a loss of fluids to, or from, the environment as long as the second barrier is intact.

CSIRO discusses in detail the three commonly considered well barrier failure mechanisms:

- failure during drilling and prior to casing;
- failure of the casing; and
- failure of the cement.

53 CSIRO 2017.

5.4.2.1 Failure mechanisms related to drilling

Drilling is the first step in constructing a well. Prior to the casing and cement being installed into the borehole, there are a number of potential risks to the early integrity of a well, such as loss of drilling fluid out of and into shallow aquifers, or into the borehole, or distorted geometry of the wellbore (for example, enlargement of the borehole size). During drilling, the primary well barrier is the drilling fluid pressure exerted on the rock formation surrounding the well, with the drilling fluid density or mud weight playing a vital role in maintaining well integrity prior to a casing being cemented. Blowout of onshore shale gas wells is unlikely during drilling because of the very low permeability of shale gas reservoirs.

Risks of losses of drilling fluid during drilling can be reduced by the identification of geological hazards prior to drilling, the monitoring of drilling fluid pressure and volume, and the use of well control equipment.

5.4.2.2 Failure mechanisms related to casing

Failure of the wellbore casing could allow loss of fluid to the surrounding rock formations. Issues with casing can be caused through poor cementing placement, leaking through casing connections, corrosion of the casing, or casing unable to withstand the pressures during hydraulic fracturing. Corrosion can potentially attack every metal component, including the casing, at all stages in the life of an oil and gas well.[54] Corrosion-induced casing damage and loss of well integrity have been widely reported.[55] The cement quality, cement sheath, and bonding integrity, play a critical role in protecting the casing from external corrosion. Cement degradation, failure of the cement sheath, and de-bonding of the interfaces along the casing and rock formation can expose the casing to corrosive fluids (if present), and casing corrosion can start. Corrosion rates depend on the type of steel used, with higher rates for mild carbon steel compared to lower rates for stainless steel or steel coated with corrosion resistant material.[56]

Risks of casing failure can be reduced, however, by monitoring casing pressure, using multi-finger calliper logs and magnetic thickness tools to gauge casing integrity, employing borehole camera inspections, and casing patching and repair, if needed.

5.4.2.3 Failure mechanisms related to cement

Failure of the casing cement can create a conductive pathway and allow movement of fluid or gas up the cement annulus outside the casing. Potential failure modes include channels or voids in the cement, gaps between the wall of the wellbore and the cement, gaps between the cement and the casing for the inner layers of the multi-casing system, and poor adhesion to the casing. These issues can be caused through poor cement placement, leaking through casing connections, and cement sheath degradation.

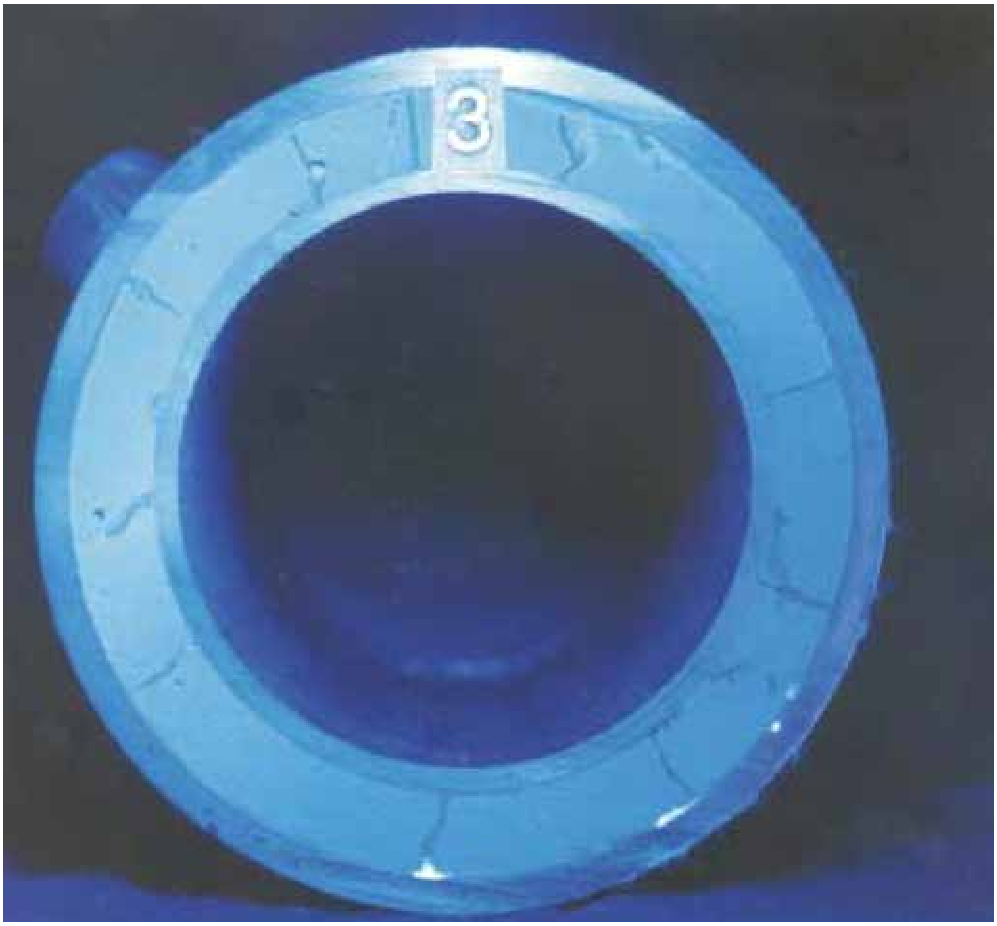
The consistency and quality of casing cement is assessed using a technique called a cement bond log (**CBL**).[57] This is based on the use of sound waves to detect flaws in the cement. Electronic measuring tools are lowered into the well to measure (or log) the cement along the depth of the well. Sound waves are used to look at how effectively the metal 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 located along the tool. If the cement bonding is good, sound will not easily transmit through the pipe. Conversely, if the cement bonding is poor, the pipe is free to vibrate, allowing for easy transmission of sound. In the event a problem is detected by the CBL, there are various techniques that can be used to repair the compromised zone.[58]

A good cement sheath is characterised as a very low permeability solid,[59] with strong bonds to the casing and rock formation surfaces, which means that fluids and gasses cannot migrate within or through the sheath. However, even if the cement sheath is initially in very good condition, large perturbations of pressure and temperature caused by casing pressure tests

54 Brondel et al. 1994.
55 Bazzari 1989; Vignes and Aadnoy 2010; Watson and Bachu 2009.
56 Kreis 1991; Elsener 2005.
57 Australian Petroleum Production and Exploration Association, submission 215 (**APPEA submission 215**), p 22; Jeffrey et al. 2017, Section 3.5; Cameron 2013.
58 Durongwattana et al. 2012; Roth et al. 2008; Ansari et al. 2017.
59 Parcevaux et al. 1990.

and hydraulic fracturing can induce radial deformation of the casing and failures in the cement sheath, resulting in de-bonding on the interfaces between the cement sheath and the casing, and the cement and the formations, creating radial fractures (**Figure 5.12**) and migration pathways.[60]

Figure 5.12: Cement sheath failure, resulting in cracks developing from pressure cycling on the internal casing. Source: Watson et al.[61]



The impact of failure of either the cement sheath or the bonds with the casing or rock formations on well integrity will depend on the extent of such failure along the wellbore and specific geological conditions. For example, one study found that in the Gulf of Mexico that there was no breach in isolation between formations with pressure differentials as high as 97 MPa (14,000 psi), as long as there was at least 15 m of high quality cement seal between the formations to ensure sufficient vertical isolation between them.[62]

Risks of cement failure can be reduced by good quality geological information, including fractured formations or zones, and identification of hydrocarbon bearing formations in the overburden and aquifers, good drilling practices to provide high quality intact bore hole for cementing; cement bond logging to investigate the integrity of the cement sheaths; and remedial cement repairs applied to identified problem zones.

60 Goodwin and Crook 1992; Watson et al. 2002.
61 Watson et al. 2002.
62 King and King 2013.

5.4.2.4 Long-term stability and integrity of cement

The cement used in well construction and abandonment is designed to have a long life span. There have been no studies on the long-term durability of cements of shale wells in Australia because the industry is only in its initial stages of development. However, there have been a number of overseas studies investigating the degradation of cement under simulated carbon dioxide (**CO_2**) geological storage conditions.[63] These have focussed on the behaviour of cement and the cement-rock and cement-casing bonding when exposed to high levels of CO_2, which is a much more corrosive environment than that found in a shale gas basin.[64]

A numerical model simulating the geochemical reactions between the cement seals and CO_2[65] was developed and validated using the laboratory experimental results by Satoh et al. prior to its application to abandoned wells.[66] The simulation of the geochemical reactions showed that the alteration length (that is, the length of cement with degraded properties) of cement seals after 1000 year exposure was approximately only 1 m, resulting in the conclusion that the length of the cement plug that was used would be able to isolate CO_2 (and therefore methane) in the reservoir over the long-term.

There have also been several relevant studies conducted to investigate the effect of well cement exposed to a mixture of acid gases (CO_2 and hydrogen sulfide (**H_2S**)).[67] The results have revealed that given a moderate concentration of H_2S in the acid gas, increases in porosity and permeability of the cement are mainly determined by how much secondary carbonate mineral species are formed in the cement. Formation of sulphur-bearing minerals as a result of interaction between cement and H_2S does not result in significant porosity and permeability changes, and therefore, loss of mechanical strength of the cement.

Given that extent of corrosion and cement degradation is likely to be much greater with CO_2 at high pressure than with methane,[68] the Panel has concluded that if onshore shale gas wells are properly designed, installed and maintained, the risk of long-term leakage from the wells through degradation of the cement will be low.

5.4.2.5 Potential impact of hydraulic fracturing on well integrity

The high pressures experienced during fracturing can damage the well casing and lead to the escape of fluids. Therefore, to maintain integrity, the well and its components must have adequate strength to withstand the stresses created by the high pressure of hydraulic fracturing fluid because if the well and casing are not strong enough to withstand these stresses, a casing failure may result.

Casing failures during hydraulic fracturing operations, or shortly following operations have been reported in the US and Australia.[69]

In the NT, the Baldwin 2HST-1 well experienced a shallow casing failure during the first stage of hydraulic fracturing in 2012.[70] In this instance, the multiple casing design protected the shallow aquifer according to groundwater monitoring data, noting, however, that the fluid in use at the time had minimal chemical content. The well was subsequently abandoned.

Multiple high-pressure events associated with hydraulic fracturing operations can also damage the cement sheath outside the casing and lead to fractures (cracks) within the cement sheath, or between the cement sheath and the casing or rock formation (de-bonding). If these cracks become extensive along the wellbore, they can allow migrations of fluid or gas. Gas (in particular, methane) migration is more likely than fracturing fluid migration because the lower density of the gas provides a larger driving force for migration through these cracks than for water. From the data available, methane migration along cracks appears to be the most likely well integrity issue caused by this process. However, the rate of methane leakage along any potential cracks is likely to be very low because of the limited aperture of this pathway and the limited driving force.[71]

63 Satoh et al. 2013.
64 Satoh et al. 2013; Popoola et al. 2013.
65 Yamaguchi et al. 2013.
66 Satoh et al. 2013.
67 Jacquemet et al. 2012; Kutchko et al. 2011; Zhang et al. 2015.
68 Popoola et al. 2013.
69 US EPA 2015.
70 DPIR submission 226, p 55.
71 Rocha-Valadez et al. 2014.

5.4.2.6 Summary

Historically, the highest instance of well barrier integrity failure appears to be related to insufficient or poor quality cementing coverage to seal aquifers and/or hydrocarbon bearing formations. In older wells this is likely due to lack of information on non-reservoir hydrocarbon bearing geological layers and the weak regulatory regime under which the wells were constructed. The other common well barrier integrity failure mechanism is associated with the degradation of the cement sheath and the cement bonds to the casing and rock formations. This failure mechanism can be exacerbated if the well is subjected to cyclic pressures, such as those experienced during hydraulic fracturing. There is also a growing body of research conducted on cement durability related to CO_2 storage which is relevant because CO_2 is considered more corrosive than methane gas. This research has indicated that even after 1,000 years only a small fraction of the total available length of the cement seals will have been degraded. Well barrier integrity failure can also occur through corrosion of the well's metal casing. If a well barrier failure is observed, or suspected to have developed, technologies, tools and mitigation measures are available to conduct mitigation operations, as has been discussed in previous sections (Section 5.2.3.4).

5.4.4 Well failure rates

5.4.4. 1 Review of international published data

CSIRO has reviewed the well barrier and well integrity failure rates reported in the open literature.[72] Well barrier failure is identified in a number of ways, including by the sustained casing pressure, surface casing vent flow or requirements for remediation of barriers. Well integrity failure is identified by the detection of hydrocarbons in nearby water wells, gas migration outside the surface casing, or detection of solutes in groundwater. CSIRO notes that many studies of well integrity do not make the distinction between failures of individual barriers and well integrity failures, a distinction that is critical because a full integrity failure (that is, the failure of multiple barriers) is required in order to provide a pathway for any contamination of the environment.

CSIRO (**Table 5.1**), largely using data sets from the US, found that the rate of well integrity failures that have the potential to cause environmental contamination is in the order of 0.1%, with several studies finding no well integrity failures, while the rate for a single well barrier failure was in the order of 1-10%.

Table 5.1: Summary of published well integrity data specific to shale gas resource development. Source: CSIRO.[73]

Study	Time period	Number of wells	Well barrier issue rate	Well integrity failure rate
Pennsylvania	2010 - Feb 2012	4,934	7.6%	Not reported
Pennsylvania	2008 - August 2011	3,533	2.6%	0.17% blowouts and gas migration
Pennsylvania	2005 - 2012	6,466	3.4%	0.25% release to groundwater
Pennsylvania	2002 - 2012	6,007	6.2%	Not reported
Pennsylvania	2005 - 2013	8,030	6.3%	1.27% leak gas to surface
Colorado	2010 - 2014	973	0	0
Texas	1993 - 2008	16,818	0	0

Importantly, there are few studies that have investigated the correlation between well construction methods, geological conditions and failure rates.[74] Stone et al. found strong correlations between well construction category and well barrier failure rates, and well barrier failure rates and well integrity failure rates, with very few barrier failures observed for wells constructed to Category 9 (**Table 5.2**) or above, and no well integrity failures for that category (standard) of well construction.

72 CSIRO 2017.
73 CSIRO 2017 and references therein, p45.
74 Watson and Bachu 2009; Stone et al. 2016a.

Table 5.2: Wellbore barrier categories that are ranked from highest risk to lowest risk. Modified from Stone et al.[75]

Barriers	Category	Surface Casing	Intermediate Casing Strings	Level of top of production casing cement	Risk Level
1	1	Shallow		Below over pressured hydrocarbon reservoir	High
1	2	Shallow		Below under pressured hydrocarbon reservoir	
2	3	Shallow		Above top of gas	
2	4	Shallow		Above surface casing shoe	
3	5	Deep		Below under pressured hydrocarbon reservoir	
3	6	Deep		Above top of gas	
4	7	Deep		Above surface casing shoe	
5	8	Deep	1	Below top of gas	
4	9	Shallow	1	Above casing shoe	
6	10	Deep	1	Above top of gas	
6	11	Deep	1	Above casing shoe	
8	12	Deep	2	Above casing shoe	Low

The Panel notes that, *"Origin's internal standards would require a well to meet Category 6 requirements, at a minimum, during production operations and at least Category 7 for well abandonment. The design of Origin's Beetaloo wells align with the Category 9 requirements."*[76]

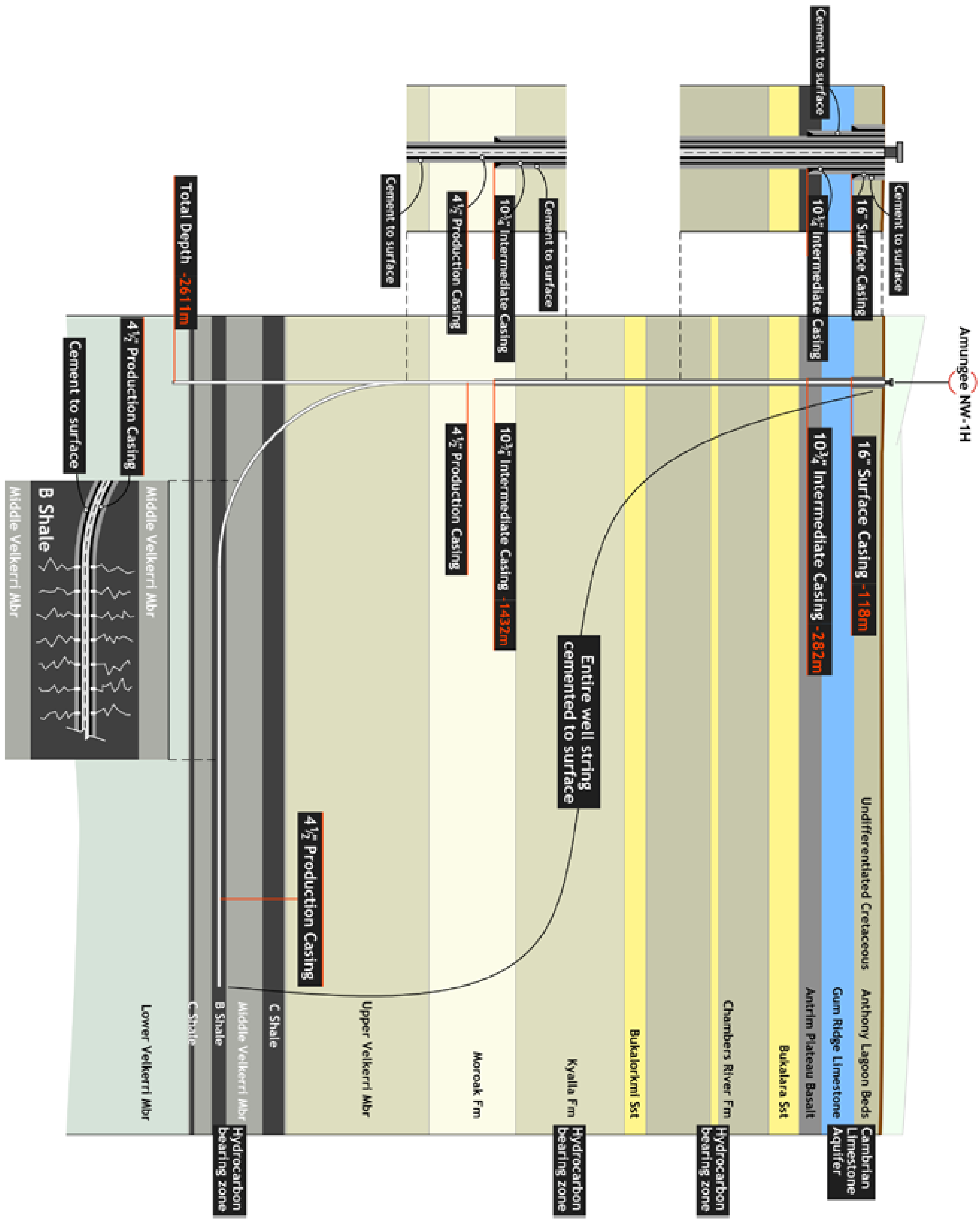
Origin also stated that, *"Beetaloo wells are designed such that the surface casing is always set below the deepest aquifer and the intermediate and production casing strings are cemented to surface to ensure isolation between the hydrocarbon bearing formations and the aquifers. The design addresses the Environmental Protection Authority (EPA)'s two primary causal factors of aquifer contamination resulting from fluid migration pathways within and along the production well which are:*

- *Inadequate surface casing depth (i.e. casing not set below the aquifer).*
- *Inadequate top of cement (i.e. cement not set above the shallowest hydrocarbon bearing zone)."*[77]

The design of the Amungee NW-1H well is shown in **Figure 5.13** to illustrate what is meant by a Category 9 standard of well construction that incorporates cement casing from the shale formation to the surface.

75 Stone et al. 2016a.
76 Origin submission 153, p 56.
77 Origin submission 153, p 56.

Figure 5.13: Casing configuration for wells drilled in the Beetaloo by Origin that ensures isolation of aquifers and hydrocarbon bearing zones. Source: Origin.[78]



78 Origin submission 153, p 57.

Watson and Bachu demonstrated that well barrier failure rates reflect the geological conditions of the wells, the regulatory requirements in place during well construction and abandonment, the era of the well construction, the well type, the well purpose and history, and many other factors (such as oil price, equipment used, materials available, operators' technical competence in the well construction, and abandonment).[79] They also found that occurrence of well barrier and well integrity failures decreased for newer wells.

5.4.4.2 Queensland

The Queensland Gasfields Commission has published statistics on well integrity compliance audits undertaken from 2010 to 2015 on CSG wells.[80] During this period, 6,734 CSG exploration, appraisal and production wells had been drilled in Queensland, and approximately 3,500 wells were actively producing at the end of 2014. The non-producing wells had no gas flow at the well head. The audit involved both subsurface gas well compliance and surface wellhead compliance testing. For the subsurface equipment, no leaks were reported and there were 21 statutory notifications (a rate of 0.3%) concerning suspect quality of down hole cement during construction. After remediation, the cement failure rate was determined to be 0%. For subsurface equipment, it may be concluded that the risk of a subsurface breach of well integrity can be assessed as very low to almost zero.

5.4.4.3 Western Australia

Patel et al. reported a study on well integrity issues for all the oil and gas wells drilled onshore in WA, and including offshore wells in State waters, that have not yet been decommissioned.[81] The study found that 122 out of 1,035 non-decommissioned wells (that is, 12%) had compromised well barriers. Tubing failure dominated well barrier failure occurrences. Of the 1,035 wells studied, 86 wells had tubing failure (or 8.3% of the total wells studied). Tubing leaks can occur through holes corroded or eroded by production and injected fluid inside the tubing or from the twisting of the tubing. Casing failure occurs predominantly in production casing due to corrosion, pressure differential, and thermal effects, causing the pressure behind the production casing to exceed the collapse resistance of the casing. Approximately 22 out of the 1,035 non-decommissioned wells had production casing failure (or 2% of the total wells studied).

However, none of the 122 wells with single barrier failures had leakage to the external environment. That is, there was no failure of well integrity.

5.4.4.4 South Australia

CSIRO could not locate any publicly available information on well integrity from this state.

5.4.4.5 Conclusions on well failure rates

Current industry practice for onshore shale gas well design is to have a minimum of two independent and verified physical barriers in place to maintain well integrity. A well integrity failure requires the failure of both physical barriers. Well integrity issues that include the degradation or the failure of one barrier in a multi-barrier system will not lead to the release of fluids from the well. But such well barrier issues are often included in studies of well integrity for oil and gas wells. The incidence of well integrity failure (that is, where all barriers fail), which is required for an actual release of fluids to the environment, are significantly lower, typically less than 0.1%.

Recommendation 5.3

That in consultation with industry and other stakeholders, the Government develop and mandate an enforceable code of practice setting out the minimum requirements that must be met to ensure the integrity of onshore shale gas wells in the NT. This code must require that:

- ***all onshore shale gas wells (including exploration wells constructed for the purposes of production testing) be constructed to at least a Category 9 (or equivalent) standard, with cementing extending up to at least the shallowest problematic hydrocarbon-bearing, organic carbon rich or saline aquifer zone;***

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79 Watson and Bachu 2009.
80 Queensland Gasfields Commission 2015.
81 Patel et al. 2015.

- *all wells be fully tested for integrity before and after hydraulic fracturing and the results be independently certified, with the immediate remediation of identified issues required;*
- *an ongoing program of integrity testing be established for each well during its operational life. For example, every two years initially for a period of 10 years and then at five-yearly intervals thereafter to ensure that if any issues develop they are detected early and remediated; and*
- *the results of all well integrity testing programs and any remedial actions undertaken be publicly reported.*

5.5 Management of well integrity

5.5.1 Objective versus prescriptive regulation

The current NT regulator has signalled its intention to adopt an objective-based regulatory regime. In this regard, the Government introduced the objective-based Petroleum Environment Regulations in 2016, and has indicated that it will replace the highly prescriptive Schedule with more objective-based resource management and administration regulations as soon as possible. The Petroleum Act and its subordinate legislation will be supported by guidelines and codes of practice that will assist in the interpretation and implementation the regulations.

The WA and Commonwealth unconventional gas regulatory frameworks are examples of objective-based regulation. WA's regulations require that a well management plan be in place for any well activities, and the regulations set out what must be included in a well management plan.[82] The regulations do not prescribe minimum technical requirements. Rather, the gas company must demonstrate that it is managing risks in accordance with *"sound engineering principles, codes, standards and specifications" and "good oil-field practice"*.[83] In addition to the need for a well management plan under the regulations, there must also be an approved environment plan under WA's petroleum environment regulations, and the environment plan must demonstrate that the environmental risks and impacts associated with the well activities have been reduced to levels that are ALARP and acceptable.[84]

By contrast, Queensland and NSW have codes of practice developed that prescribe how well integrity is to be achieved. The codes were developed in consultation with industry and other stakeholders.

In Chapter 14, the Panel gives consideration to the risks and benefits of objective-based and prescriptive regulation. The Panel concludes that in the NT context where onshore shale gas is an emerging industry, a level of prescription is required to provide certainty to gas companies and regulators about the performance standards and criteria that must met. However, Chapter 14 also proposes that prescriptive and enforceable codes of practice and guidelines can operate alongside objective-based regulation to ensure that world leading practice is implemented and to ensure that appropriate environmental outcomes are achieved.

5.5.2 Management of well integrity in the NT

5.5.2.1 Drilling petroleum wells

The current process for drilling activities in the NT requires gas companies to describe components of well integrity management, but the legislation does not explicitly require an overall well integrity management plan for the full life cycle of a well.[85]

A gas company must have Ministerial approval to drill a petroleum well.[86] To obtain approval, the gas company must submit an application,[87] which includes details about the proposed drilling program.[88] The Schedule does not make it clear how the Minister approves the application, when the application must be approved by[89] or what matters the Minister must be satisfied of to grant

82 *Petroleum and Geothermal Energy Resources (Resource Management and Administration Regulations) 2016* (WA), cls 10 and 17.
83 *Petroleum and Geothermal Energy Resources (Resource Management and Administration Regulations) 2016* (WA), cl 16(1)(c).
84 *Petroleum and Geothermal Energy Resources (Environment) Regulations 2012* (WA), cls 11(1)(b)-(c).
85 CSIRO 2017, p 64.
86 Schedule, cl 301(1).
87 Schedule, cl 301(2).
88 Schedule, cl 301(2)(i).
89 The guideline entitled *Well Drilling, Work-over or Stimulation Application Assessment Process* provides that the *"project application"* will be processed in 30 days; however, it has no statutory force.

the approval. Further, it is implied, but not expressly stated, that the gas company must comply with the approved application and drilling program.

In addition to the requirement to have an approved application and drilling program in place, the Schedule prescribes that equipment and casing used to drill and construct the well must conform to American Petroleum Institute (**API**) standards,[90] that blowout prevention systems must be in place,[91] casing strings must be cemented to the surface,[92] and pressure testing must take place.[93]

With regard to well integrity, DPIR has implemented a process of continually assessing well integrity status during drilling operations.[94] Specifically, the *Well Integrity Verification Form,* which was developed following the Montara Commission of Inquiry, requires the regulator to evaluate the integrity of the well, confirming that the well has been constructed to levels exceeding API standards. This assessment is based on information provided by the tenure holder in daily drilling and other reports, in addition to the well planning information submitted in the application for approval for the drilling activity. More details on the extent of information required by the regulator are documented in the CSIRO report.[95]

5.5.2.2 Hydraulic fracturing

Hydraulic fracturing, like drilling, requires a separate approval under the Schedule.[96] An application to conduct hydraulic fracturing must be accompanied by a *"technical works program"*, which must include information about, among other things, the well status, any pressure tests, an interpretation of cement evaluation logs, design of the hydraulic fracturing program, and geological and geomechanical hazards.[97] DPIR uses a document called *Checklist - Well Work-over and Stimulation Program Assessment* to ensure all the relevant information has been provided,[98] but, similarly, the checklist has no legal basis and cannot be used to enforce compliance with the provisions of the Schedule.

Like the approved drilling program, the Schedule does not expressly require that an approved technical works program for hydraulic fracturing must be complied with, which can create problems in the event that the Minister for Resources attempts to enforce compliance with an approved program. Again, the Schedule does not prescribe how, or when, an application to conduct a hydraulic fracturing program will be approved, or the matters the Minister must take into account when approving such a program. Chapter 14 includes a discussion and recommendations regarding the use of the Schedule as a regulatory tool.

5.5.3 Well integrity management system

Management of well integrity throughout the well life cycle has become a focus over recent years in response to the recognition of the value of proactive well integrity management in reducing risks.[99] Wells need to be designed cognisant of the potential hazards that might arise throughout their life cycle, including hydraulic fracturing. The operating life of a well can span several decades, and responsibility for the well is often passed between different teams within a gas company and third parties involved in well drilling and operations. The level of complexity in the design and operating parameters for wells means that there are risks associated with the transfer of responsibility throughout the life of the well. Life cycle well integrity management aims to minimise these risks by placing processes around well integrity management. Origin provided the Panel with information on the well integrity management system it employs.[100]

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90 Schedule, cl 303(1).
91 Schedule, cl 308.
92 Schedule, cl 307.
93 Schedule, cl 309.
94 DPIR submission 226, p 34.
95 CSIRO 2017; DPIR submission 226, pp 28-33.
96 Schedule, cl 342(1).
97 Schedule, cl 342(2).
98 DPIR submission 226, pp 224-235.
99 Wilson 2015; Connon and Corneliussen 2016; Sparke et al. 2011; Smith et al. 2016.
100 Origin submission 153, pp 55-68.

The focus on well integrity management has led to the development of ISO 16530-1:2017, which states that:

> *"the well operator should have a well integrity management system to ensure that well integrity is maintained throughout the well life cycle by the application of a combination of technical, operational and organizational processes".*[101]

The NORSOK D-010 standard also requires management of well integrity requirement throughout the life cycle of a well.[102]

A well integrity management system (**WIMS)** provides a framework for managing the risks due to loss of well integrity over the life cycle of a well, and identifies the responsibilities of the organisation as a whole in safeguarding environmental assets and public health. CSIRO has listed the following as the key elements of a WIMS:[103]

- risk assessment that includes techniques to identify the well integrity hazards and associated risks over the life cycle of the well, methods to determine acceptance levels for risks, and to define control measures and mitigation plans for managing and reducing risks that exceed acceptance levels;
- an organisational structure with clearly defined roles and responsibilities for all personnel involved in well integrity management;
- well barrier documents that clearly identify and define well barriers (combination of components or practices that prevent or stop uncontrolled movement of well fluids), methods to combine multiple barriers and redundancies to ensure reliability, and administrative controls that provide information on controlling activities related to well integrity, such as design and material handling standards, procedures, and policy manuals;
- performance standards for people, equipment, and management systems;
- defined standards for well barrier verification such as functional, leak and axial load tests, and well load case modelling verification to ensure that well barriers meet all acceptance criteria;
- a continuous improvement process that defines how knowledge and information should be communicated to personnel responsible for well integrity during the life of the well and how improvements can be implemented;
- a change management process to record changes to well integrity requirements for an individual well or the WIMS itself; and
- an audit process that demonstrates conformance with the WIMS.

A comprehensive system for well integrity management should also set out the regulator's responsibilities for review and assessment of a gas operator's well integrity management approach and for an inspection regime to ensure compliance. The system should also specify the operator's reporting requirements for well integrity incidents, in addition to establishing penalties for non-compliance.

Further, assessment of well integrity management on a well-by-well basis is necessary to address well-specific risks. Well integrity hazard identification and risk assessment is an important component of well integrity management.

Commonwealth and WA regulations require the development of well management plans by operators that outline the risk assessment approach used, the risks identified, and the well integrity management practices that must be put in place and submitted to the regulator for assessment. The current project application process for drilling activities in the NT contains requirements for the gas operator to describe components of well integrity management, but it currently does not explicitly require an overall well integrity management plan for the full life cycle of a well.[104] It is the Panel's opinion that it should.

101 ISO 2017.
102 Standards Norway 2013.
103 CSIRO 2017, pp 50-51.
104 CSIRO 2017, p 59.

Recommendation 5.4

That gas companies be required to develop and implement a well integrity management system for each well in compliance with ISO 16530-1:2017.

That each well must have an approved well management plan in place that contains, at a minimum, the following elements:

- ***consideration of well integrity management across the well lifecycle;***
- ***a well integrity risk management process that documents how well integrity hazards are identified and risks assessed;***
- ***a well barrier plan containing well barrier performance standards, with specific reference to protection measures for beneficial use aquifers;***
- ***a process for periodically verifying well barrier integrity through the operational life of the well and immediately prior to abandonment, and for reporting to the regulator the findings from integrity assessments;***
- ***characterisation data for aquifers, saline water zones, and gas bearing zones in the formations intersected during drilling; and***
- ***monitoring methods to be used to detect migration of methane along the outside of the casing.***

5.6 Water use

Shale gas extraction requires the use of large quantities of water, which may be obtained from local surface or groundwater sources, or transported to the site from outside the region. This water is typically stored in large, above-ground ponds or tanks.[105]

There has been a substantial amount of data published over the past decade regarding the volumes of water used for drilling and hydraulic fracturing.[106] Considerable care needs to be taken in interpreting this information because of the rapid changes in technology that have occurred during this period, and the differences in water use and well density between vertical and horizontal wells. In particular, the increasing use of multi-well assemblies in association with much longer horizontal well sections is profoundly changing the water use profile of the industry.

In the US, the most recent long horizontal wells require 30-40 fracturing stages, with a current overall industry average of 16 stages per horizontal well. This requires a proportional increase in water use per well. For example, a 3 km horizontal well requires three times as much water as a 1 km horizontal well. Typical water volumes used are around 1-2 ML for well drilling, and approximately 1-2 ML for each hydraulic fracturing stage.[107]

The water-related risks associated with any onshore shale gas industry in the NT are covered in detail in Chapter 7.

5.7 Wastewater production and composition

Three main sources of wastewater are produced during the shale gas extraction process:

- **drilling mud water:** used to drill the initial wellbore;
- **flowback water:** returned to the surface in the first few weeks to months after hydraulic fracturing has occurred; and
- **produced water:** from the shale layer produced over the lifetime of the well.

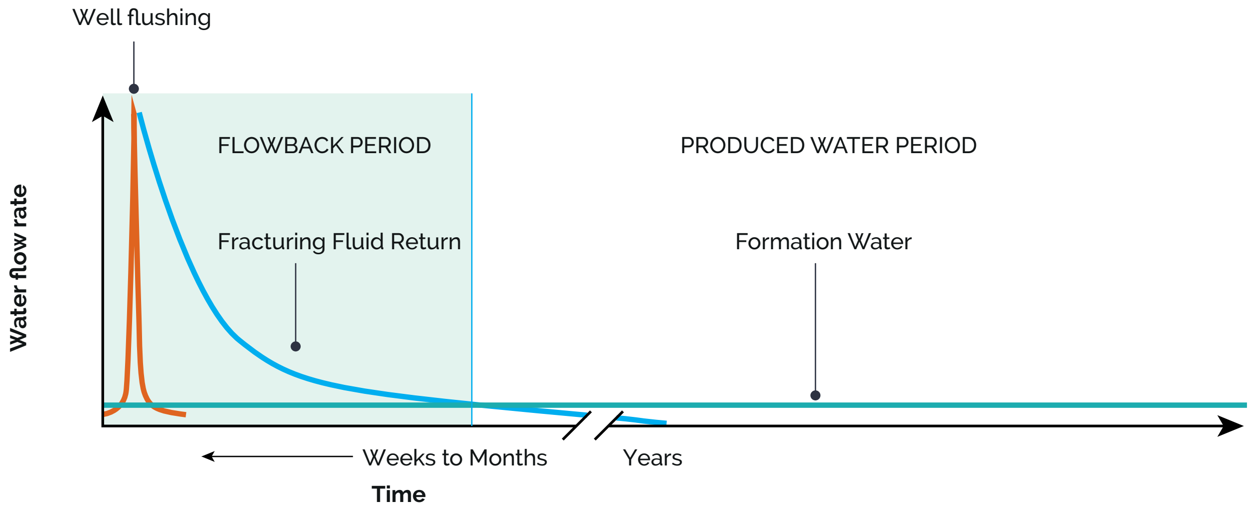
105 Hoffman et al. 2014.
106 ACOLA Report; US EPA Report.
107 ALCOA Report; US EPA Report; APPEA submission 215.

5.7.1 Wastewater production

The volume of wastewater produced from drilling a well represents the smallest volume (1-2 ML) of wastewater produced during well development. Drilling fluids (drilling mud) are an essential component of drilling operations, and are distinct from hydraulic fracturing fluids used during well stimulation.[108] These fluids provide cooling and lubrication to the drill bit and drill string, lift drill cuttings from the well, and provide a component of well control. Used drilling fluids are typically contained in lined sedimentation pits. The settled, typically saline, supernatant is removed for treatment elsewhere, while the 'mud' component is recycled for use in other drilling operations.

As described above, when a well is hydraulically fractured, this is done in stages, with each stage plugged while the next is being perforated and fractured. This creates an increase in pressure and a backup of both fluids and gas while further stages are being drilled. When the final stage is drilled, the fluids and gas are allowed to flow up out of the well for a period of up to two months (**Figure 5.14**). This is the 'flowback period', where the water returning from the well is composed partially of drilling and injected hydraulic fracturing fluids, and partially of formation brines that are trapped in the target formations and are extracted together with the gas.[109] Shown in **Figure 5.14** is the short 'flushing period' where the residual fluids and solids in the well, produced as a result of the hydraulic fracturing process, are cleaned out in advance of preparing the well for production. This water has been grouped with 'flowback', although it can be of such poor quality that it may be segregated for separate treatment or disposal, rather than re-use.

Figure 5.14: The difference between flowback and produced water.



The water generated after the flowback period during the lifetime of gas production is 'produced water', the composition of which resembles the original formation water present in the shale layer.[110]

Depending on the nature of the hydrocarbon-containing shale formation, 20-50% of the volume of the initially injected water is returned to the surface as flowback water. Therefore, for a typical 20 ML total volume of water used to hydraulically fracture a horizontal well, approximately 4-10 ML could come back to the surface as flowback water.[111] Based on US experience, the discharge of flowback water typically lasts for 4-6 weeks, during which time the discharge rate decreases from about 550 L/min to about 4 L/min.[112] Once above ground, the flowback water is usually stored in either temporary storage tanks or ponds or conveyed by a pipeline to a wastewater treatment plant.[113] Which of these two methods is used depends on the rate of flow of the water, whether it is going to be re-used for fracturing another well on the same well pad, and the distance between the well pad and the collection/treatment facility.

108 Hossain and Al-Majed 2015, pp 73-139.
109 Kondash et al. 2017.
110 Kondash et al. 2017.
111 ACOLA Report; US EPA Report.
112 Ziemkiewicz and He 2015.
113 US EPA Report.

The initial period of flowback water collection (up to two months) is followed by a production period of 20 to 40 years, during which time typically a much smaller amount of produced water returns to the surface along with the gas produced.[114] Although the rate of flow is very much less than during the initial flowback stage, in aggregate, the volume of produced water can be quite substantial. Again based on US experience, the ratio of volume of flowback to produced water is very dependent upon the formation.[115] The produced water also is usually collected and conveyed to a central storage or treatment facility for the life of the well.

5.7.2 Composition of hydraulic fracturing fluid

The composition by volume of a typical water-based hydraulic fracturing fluid is 90% to 97% water, 2% to 10% proppant, and 2% or less of additives.[116] The proportions of water, proppant, and additives in the fracturing fluid, and the specific additives used, can vary depending on a number of factors, including the rock type and the chemistry of the reservoir.

Hydraulic fracturing fluids are generally either 'slickwater' or gel-based.[117] 'Slickwater' formulations, which include polymers (for example, polyacrylamide) as friction reducers, are typically used in very low permeability reservoirs, such as shales. Because slickwater fluids are thinner (lower viscosity), they do not carry proppant into the fractures as easily, and therefore the larger volumes of water and greater pumping pressures are required to effectively transport the proppant into fractures. By contrast, gelled fluids are more viscous, and more proppant can be transported, with less water, compared to slickwater fractures. Gel-based fluids are used with more permeable formations.

The US EPA found that approximately 1,100 different chemicals had been used in hydraulic fracturing in the period between 2005 and 2013. [118] Hydraulic fracturing technology has evolved rapidly over the past decade, and much greater attention is now being paid to the potential for contamination of below-ground and surface environments, with a much smaller fraction of these chemicals now being routinely used in modern hydraulic fracturing practice. For example, a detailed analysis (based on 34,675 disclosures and 676,376 ingredient reports contained in the US FracFocus database) of the chemical usage data in the US between January 2011 and February 2013 showed that only 5% (35) of the total identified number of chemicals previously used were used in most of the fracturing operations over that period.[119] Additionally, there has been a strong move over the last decade by industry to use less toxic and more readily degradable chemicals, or so-called 'greener' chemicals. [120]

However, technology providers did not disclose the actual identity of 381 chemicals, and claimed those chemicals, or chemical mixtures, as confidential business information (**CBI**).[121] The use of CBI reduces the completeness of the data sets and the level of confidence in any assessment of the toxicity of chemical used in hydraulic fracturing. The issue of CBI is contentious and is anecdotally one of the reasons for industry moving towards the use of non-proprietary chemicals that can be openly disclosed in databases like FracFocus.[122]

The Panel notes that public disclosure of *"specific information regarding chemicals"* used in hydraulic fracturing is required in the NT.[123] For example, the chemicals used for the eight unconventional wells[124] that have been hydraulically fractured in the NT are available on the DPIR website.[125] The 40 chemicals used (Table 7.7) for Origin's Amungee NW-1H production test well were disclosed by Origin to the Government and to the Panel.[126] This list is a subset of the much larger list compiled by the US EPA of the chemicals used in the US.[127]

114 Kondash and Vengosh 2015.
115 Kondash and Vengosh 2015; Kondash et al. 2017.
116 US EPA Report, pp 3-21.
117 US EPA Report, pp 3-21.
118 US EPA Report.
119 US EPA Report.
120 King 2012; BHP 2016; Halliburton Australia Pty Ltd, submission 221 (**Halliburton submission 221**), p 5.
121 US EPA Report.
122 www.FracFocus.org.
123 Schedule, cl 342(4).
124 DPIR submission 226, p 47.
125 At https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/chemical-disclosure-reports.
126 Origin submission 153.
127 US EPA Report.

5.7.3 Composition of flowback and produced water

The initial composition of the flowback water generated immediately after hydraulic fracturing ceases when the pressure is relieved, is likely to closely resemble depleted fracturing fluid. However, with time, the decreasing daily volumes of fluid produced will contain increasing quantities of the mobile (soluble) geogenic components present in the fractured rock and will ultimately resemble the original formation fluid in the shale layer.[128] Typically, the flowback water produced after the initial flush is quite saline (greater than 50,000 mg/L TDS), especially if the target formation is of marine origin.

Flowback water contains residual chemicals used in the hydraulic fracturing process plus geogenic chemicals that originate from the shale formation itself.[129] These geogenic chemicals include salts, metals and metalloids, organic hydrocarbons, and naturally occurring radioactive material (**NORM**), depending on the geochemistry of the deposit. The actual concentrations of these various components depend both on the geochemical nature of the target formation and on the hydraulic fracturing process used.

Produced water is typically very saline (50,000 - 200,000 mg/L TDS) with higher concentrations of geogenic chemicals than in flowback water, but with very little of the chemical signature of the fracturing fluid that was used.[130]

In the US, approximately 600 discrete chemicals have been detected in flowback and produced waters, and of this, only 77 were components of the hydraulic fracturing fluids used.[131] This suggests that many of the hydraulic fracturing chemicals are either retained in place or are degraded or transformed into other chemical compounds (or not specifically measured). There is increasing evidence that such transformation reactions do occur between components of the hydraulic fracturing mixture and as a result of the reaction of hydraulic fracturing components with geogenic compounds.[132]

A variety of volatile and semi-volatile organic compounds, including benzene, toluene, ethylbenzene and xylenes (**BTEX**), have been detected in flowback and produced water from shale reservoirs.[133] In particular, average total BTEX levels in shale flowback/produced water in the US have been found to be one to two orders of magnitude higher than in produced water from CSG extraction. This is an important finding because it indicates that caution needs to be exercised in extrapolating risk assessments made on CSG produced waters and applying them to flowback water from deep shales. There are, however, wide variations in the concentrations of organic compounds being measured across different shale plays,[134] which could result from lateral variations in the geology across the formation, combined with differences in the compositions of the hydraulic fracturing fluids being used.

The Panel is cautious in using US data, which is quite variable across individual shale basins, to gain an understanding of the likely composition of flowback/produced waters that will be produced in the NT. Only over the past five years have more extensive (and intensive) measurements been taken in the US of the concentrations of organic compounds present in flowback and produced water. Knowledge of flowback and produced water compositions is therefore provided by a few studies on a relatively limited number of samples wherein the full range of inorganic and organic constituents have been determined. This has limited the capacity for meaningful risk assessments of flowback/produced waters to be undertaken compared with the known chemicals present in the hydraulic fracturing formulations. This situation is also complicated by the fact that the concentrations of these organic compounds are very site specific, depending both on the shale formation being targeted and on the formulation of the hydraulic fracturing fluid(s) being used.

There is very limited data on the composition of flowback and produced water occasioned by onshore shale gas extraction in Australia, and this makes the need for empirical data from test wells all the more important. The overseas studies suggest that flowback and produced water can contain a much greater number of potentially environmentally sensitive chemicals than are present in the original hydraulic fracturing fluid composition, and moreover, that the majority of

128 Ziemkiewicz and He 2015.
129 Hayes and Severin 2012; Arthur and Cole 2014; Ziemkiewicz and He 2015; US EPA Report; Butkovskyi et al. 2017; Stringfellow et al. 2017.
130 Kondash et al. 2017.
131 US EPA Report.
132 Kahrilas et al. 2016; Tasker et al. 2016; Hoelzer et al. 2016.
133 US EPA Report; Butkovskyi et al. 2017.
134 Maguire-Boyle and Barron 2014.

these additional compounds originate from the minerals and organic compounds present in the shale formation.[135] However, because a chemical is detected in flowback or produced water does not mean that it will be harmful to human health or to the environment.

The Panel notes that while the shale gas industry in the US is now, largely required to publicly disclose the composition of hydraulic fracturing fluids in databases such as FracFocus, similar disclosure has not been required for the composition of flowback or produced waters.

This causes difficulties with the assessment of the status of water management practices in the industry, a situation that has been noted in recent publications on water sourcing, and treatment and disposal practices in the onshore shale gas industry in the US and Canada.[136]

A similar situation exists in the NT, where public disclosure of the composition of flowback or produced water is currently not mandated. This contrasts with the UK, where the *UK Onshore Shale Gas Well Guidelines* require that a range of information (including volumes and composition) about flowback fluids and produced water must be available from the operator for disclosure.[137]

The Panel notes that the DPIR supports the disclosure of analysis of flowback water and has developed guidelines stipulating baseline monitoring, testing and reporting requirements of hydraulic fracturing fluids and flowback water.[138] In addition, the DPIR suggests that the testing of flowback water may not be necessary on every (production) well if hydraulic fracturing fluids and stimulated formations are the same.

Recommendation 5.5

That the composition (inorganics, organics and NORMs) of flowback fluids, in addition to hydraulic fracturing fluids, be made publicly available.[139]

5.8 Wastewater management and reuse

5.8.1 Storage

Flowback water has typically been stored initially in open, lined surface ponds that may be constructed on the land surface or excavated below ground level.[140] In the US there has recently been a move towards storing flowback water in special purpose, above ground tanks (see ***Recommendation 7.11***).[141] The same ponds or tanks that are used to store the water used to initially formulate the fracking fluid can also be used to store flowback water, depending on quality of the water, the extent of reuse, and the volumes.

The Panel notes that since 1-2 ML of water is required for each stage of fracking, and at least 20 stages of fracking are likely, based on developing industry practice, at least 40 ML of storage will be needed per well for a fully developed production scenario. This volume will not be cumulative for a multi-well pad configuration, depending on the extent of reuse possible, and noting that the wells will be fractured sequentially rather than concurrently.

An example of the type of storage used and storage volumes required was provided by Origin in its environmental management plan for the Amungee NW-1H 11 fracturing stage test well.[142] An aerial photograph of the site showing the layout of the ponds and other site infrastructure was provided in Origin's submission to the Panel.[143]

135 US EPA Report.
136 For example, Alessi et al. 2017.
137 UK Onshore Oil and Gas 2016, section 9.3.
138 Department of Primary Industry and Resources, submission 424 (**DPIR submission 424**), p 5.
139 See Department of the Environment and Energy 2017c, Appendix A, for guidance on chemical species to be measured.
140 US EPA Report.
141 BHP 2016, p 5.
142 Origin 2016, p 21.
143 Origin submission 153, p 81.

An aerial view of the Amungee NW-1H well site showing the above ground ponds during the flowback and production testing phase. Source: Origin.

5.8.2 Treatment and reuse

The Panel notes that there is currently no industrial wastewater receiving, treatment or disposal facility in the NT. The relatively small volumes of wastewater produced to date, including from the Amungee NW-1H production test, have been transported by road to Mt Isa in Queensland. In the event that the moratorium is lifted this issue will need to be addressed as a matter of priority given the increase in volumes of water requiring disposal. While programmed re-use (see below) of such water is likely to be an operational feature of a production environment with multi-well pads, this is unlikely to be the case for the exploration phase of the industry's life cycle. The Panel has seen in Queensland the consequences of not having a plan for the ultimate fate or disposal of water treatment brines in place at the start of the upswing in development of the CSG industry. It is also noted that the long distance transport of wastewater and treatment brines is a risk factor that needs to be addressed by industry (see Chapters 7, 8 and 10).

Reuse refers to the practice of using treated or untreated flowback and produced water as a proportion of the water used to make new batches of hydraulic fracturing fluid. Reuse of wastewater can reduce, but not eliminate, the amount of fresh water needed for hydraulic fracturing since the volume of flowback water from a single well is generally small compared to the total volume needed to fracture the well.

The extent of reuse of flowback or produced water depends on its quality, as certain contaminants can interfere with hydraulic fracturing performance.[144] For example, the presence of calcium and sulfate ions can cause scaling in the well, and the presence of suspended solids can decrease the effectiveness of the biocide, which together with scaling, can cause plugging of fracture networks and wells. Slickwater fracturing systems, containing polyacrylamide polymer as a friction reducer, are generally considered best suited for reuse because most of this polymer remains in the shale. However, slickwater treatments usually require substantially more water than gel-based systems.[145]

144 Vidic et al. 2013.
145 US EPA Report, pp 3-21.

Normally, some form of treatment of the wastewater will be required before it can be reused, with the treatment method dependent upon the chemical composition of the hydraulic fracturing wastewater and the desired reuse water quality. The development of cost-effective treatment systems for the complex mixture of inorganic and organic compounds contained in flowback waters is a rapidly evolving field.[146]

Salinity is generally not an issue for the treatment of shale gas wastewaters, because high concentrations of ions, such as sodium and chloride, can be tolerated in reuse water. For example, sea water has been successfully used to prepare hydraulic fracturing fluid for offshore operations. However, high salinity flowback water can also be supersaturated with salts like gypsum, barite or calcite, which could severely compromise the efficiency of subsequent fracturing operations by causing precipitates to form and block up the newly created fracture network. In particular, when calcium and barium levels are high, scale inhibitors must be used, or salt content reduced, before the water can be re-used.[147]

Flowback water also contains a diverse range of organic compounds, some of which may be difficult to treat.[148] However, many of these organic compounds are biodegradable and could be treated in a purpose-built biological treatment plant.[149] The effective removal of these organic compounds is necessary if flowback water is to be treated and disposed of offsite, rather than being reused for hydraulic fracturing.

Removal of suspended solids, using a process such as electrocoagulation, is much less costly than the removal of dissolved salts using energy intensive processes such as reverse osmosis or thermal brine concentration.[150] Indeed, this may be the only treatment required if there are low concentrations of potentially problematic ions (for example, calcium and sulfate) in the flowback water.

However, conventional oilfield water treatment technologies (such as reverse osmosis) may not always be effective in unconventional gas projects due to specific constituents in flowback and produced water, such as residual polymers, which have the potential to severely interfere with membrane-based treatment.

Recommendation 5.6

That in consultation with industry and the community, the Government develop a wastewater management framework for any onshore shale gas industry. Consideration must be given to the likely volumes and nature of wastewaters that will be produced by the industry during the exploration and production phases.

That the absence of any treatment and disposal facilities in the NT for wastewater and brines produced by the industry be addressed as a matter of priority.

5.8.3 Reinjection

Historically, in the US there has been a generally low percentage reuse of flowback water,[151] with greater than 95% of all wastewater from oil and gas extraction having been disposed of through reinjection into disposal wells located in conventional petroleum reservoirs.[152] However, aquifer reinjection is being increasingly restricted because of concerns with potential for groundwater contamination and induced seismicity. There are no known potential onshore sites for reinjection of flowback or produced water into conventional hydrocarbon formations in the NT outside the Amadeus Basin.[153] This is covered in greater detail in Chapter 7.

146 US EPA Report, Appendix F.
147 Maguire-Boyle and Barron 2014.
148 Butkovskyi et al. 2017.
149 Kekacs et al. 2015; Lester et al. 2015.
150 Butkovskyi et al. 2017; Costa et al. 2017.
151 US EPA Report.
152 Rodriguez and Soeder 2017.
153 DPIR submission 226.

5.8.4 Wastewater management incidents

The 2016 assessment by the US EPA collated data from thousands of wells that have been drilled and fractured over the past decade.[154] It concluded that there was no evidence of widespread impact on shallow aquifers, and no demonstrated cases of contamination of drinking water resources from hydraulic fracturing at depth. However, it did identify cases of drinking water contamination from spills of fracturing fluids or flowback water, and contamination of aquifers as a result of failure of well integrity during and after hydraulic fracturing.

There is significant potential for accidental releases, leaks and spills of hydraulic fracturing chemicals and fluids, and flowback and produced water that could lead to contamination of nearby surface water and seepage through the soil profile into shallow aquifers (see Chapter 7 for greater detail).[155]

Most spills are related to the storing of water and materials in tanks and pits, and in moving wastewaters in pipelines between equipment.[156] Not surprisingly, the incidence of spills has been found to be greatest within the first three years of well life when 75-94% of spills occurred. This is the period when wells are drilled, hydraulically fractured, and have their largest water production volumes.[157]However, while there have been more than one million fracture stimulations (fracturing) treatments in North America, and more than 1,300 in the Cooper Basin in SA, there has been no reported evidence of fracturing fluid moving from the fractures to near surface aquifers.[158]

There have been instances of contamination of surface waterways by discharges of incompletely treated flowback waters. This occurred in Pennsylvania in the US during the early development of the Marcellus gas field.[159] This is a separate issue from surface spills. It occurred as a result of an inappropriate use of municipal wastewater treatment plants to treat flowback water - a function for which they were never designed - followed by discharge of the partially treated water into rivers. This practice has now been banned by US federal regulation.[160]

Hydraulic fracturing has been taking place in the NT since 1967, but mainly as a process to enhance hydrocarbon production from conventional reservoirs in vertical wells.[161] Only since 2011 has very limited hydraulic fracturing of unconventional formations been undertaken. DPIR reports that these operations have had little impact on water resources, but no specific details were provided in its submission.[162] There has been no independent assessment and reporting of environmental performance by the onshore gas industry in the NT. But in any event, the onshore gas industry in the Territory is relatively small and the performance data available is unlikely to be representative of a contemporary full-scale development.

5.9 Solid waste management

The solids produced by drilling represent a substantial waste stream associated with the production of shale gas. When a well is drilled, drilling fluids (including drilling muds) are used to maintain circulation of the drill bit and to transport drill cuttings back to the surface. Drill cuttings produced by exploration activities are typically disposed of in drill mud pits, which are backfilled to ground level when drilling is completed. Before this is done excess liquids are typically evaporated, and the drilling muds are reused in the drilling of new wells.

In the US, the disposal of the large amounts of drill cuttings produced by a full-scale industry is the cause of concern given the nature of this material and its potential to leach organic and inorganic components into the near surface environment.[163]

The magnitude of the issue is exemplified by considering the example of an 8 well pad, drilled to 3,000 m depth, with 3,000 m long horizontal sections for each well and with a 10 cm diameter wellbore. This well configuration would produce around 190 m^3 of shale material from each

154 US EPA Report.
155 US EPA Report; Maloney et al. 2017.
156 Patterson et al. 2017.
157 Patterson et al. 2017.
158 Cooke 2012; US EPA Report.
159 Mauter et al. 2014; Mauter and Palmer 2014.
160 US EPA Report.
161 DPIR submission 226, p 46.
162 DPIR submission 226, p 53.
163 Phan et al. 2015.

horizontal well and approximately the same amount of material from the vertical sections, depending on depth, excluding drilling cuttings from the larger diameter conductor and upper casings. Accordingly, approximately 870 tonnes[164] (dry weight) of shale and other material could be extracted per multi-well pad. While this is a very small amount of material compared with that produced by a typical coal or metal mine, when aggregated over hundreds of well pads it would comprise a substantial amount of material requiring appropriate management.

A strategic management issue for any potential onshore shale gas industry in the NT will be whether this solid waste should be contained in a purpose-built, engineered, and centralised facility, or contained and managed on a per well pad basis as is currently the case for the exploration phase.

Submissions received from industry in response to requests for further information from the Panel indicated that solid waste management was an issue that did need to be addressed.[165] Origin noted that, *"purpose built, engineered facilities would be required to safely manage, some solid and liquid waste generated by commercial shale development within the NT. Whether these facilities are located centrally or on each of the lease pads will be assessed as a part of the development concept. It can be stated however, that these facilities will be designed to prevent the seepage of contaminants to the environment".*[166]

Protocols and procedures have been developed by regulators, the gas industry and commercial waste handling facilities to screen drilling wastes for content of metals, NORM and hydrocarbons and to separate out cleaner fractions that can be used for other purposes, such as road base.[167] In particular, several independently owned and operated waste management facilities have serviced the solid waste management needs of the Queensland CSG industry for many years, and there is precedent for the development of such facilities in response to the demand from a full-scale gas industry.[168]

Recommendation 5.7

That in consultation with industry and the community specific guidance be implemented by the Government, drawing on protocols and procedures developed in other jurisdictions, for the characterisation, segregation, potential reuse and management of solid wastes produced by the shale gas industry.[169]

5.10 Seismicity and subsidence

5.10.1 Seismicity induced by hydraulic fracturing

There is now considerable evidence from the US and UK[170] that low magnitude earthquakes may occur during hydraulic fracturing and that larger scale (Richter scale magnitude greater than 2.0) earthquakes have occurred during the reinjection of wastewater.[171] There is potential for induced seismicity to result from the uncontrolled propagation of fractures produced during hydraulic fracturing that can extend for up to several hundred metres in varying directions in the adjacent geological strata.

Induced seismicity associated with shale gas hydraulic fracturing has been reported in both the UK and the US.[172] The US experience is that the seismicity levels vary for individual shale gas basins, which reflects a combination of the depth of the producing layers (shallower layers experience lower induced seismicity levels before shutdown of the hydraulic fracturing process occurs) and local geology (the degree of faulting in the area of interest).[173] The seismicity caused by hydraulic fracturing mostly has very low magnitudes (typically between M_W = -2-0) and is

164 Assuming a density of 2.3 t/m^3.
165 Santos submission 420, p 5; Pangaea Resources Pty Ltd, submission 427 (**Pangaea submission 427**), p 15; Origin submission 433, p 34.
166 Origin submission 433, p 34.
167 DEHP 2013; DEHP 2015.
168 Origin submission 433, p 34.
169 For example, DEHP 2013; DEHP 2015.
170 For example, de Pater and Baisch, 2011; Royal Society Report.
171 ACOLA Report; US EPA Report, p 66; Clarke et al. 2014; Warpinski et al. 2012, respectively.
172 Clarke et al. 2014; Warpinski et al. 2012, respectively.
173 Warpinski et al. 2012.

unlikely to be felt or cause infrastructure damage,[174] including damage to any wells drilled for hydraulic fracturing that have been specifically designed to withstand the stress of hydraulic fracturing. Overseas, findings to date also suggest that it is extremely rare for hydraulic fracturing stimulation to result in earthquakes of sufficient scale (Richter scale magnitude 2.0 or greater) to be felt locally or to cause even slight damage to buildings.[175]

Considerably larger earthquakes (M_W = 3-5.7) have, however, been associated with the injection of large volumes of fluid. For example, for disposal of produced water. These earthquakes often occur after high volumes of fluid have been injected into the rocks and at much lower fluid pressures than those required for hydraulic fracturing. These larger earthquakes generally have properties that suggest that they are often associated with the reactivation of existing faults rather than the creation of new hydraulic fractures. There is the possibility that any introduced water could lubricate existing geological faults, and therefore, the location of deep injection wells should be controlled by knowledge of the local geology. In particular, highly faulted areas should be avoided. The potential to induce earthquakes through the disposal of wastewater down wells can be mitigated by proper management of formation pressures.

Based upon experience in the US and UK, the extent of fracturing can be monitored using sophisticated micro-seismic technologies, with the fracturing distance controlled by varying the pressure that is used.[176] The Panel considers that implementation of the trigger levels used in the UK *Traffic Light Monitoring System*,[177] which inform the operators as to the induced seismicity occurring during hydraulic fracturing by monitoring seismic activity in real time, can reduce the likelihood of induced significant felt seismic events (earthquakes). The rules state that hydraulic fracturing must be stopped if minor earth tremors of magnitude 0.5 or greater on the Richter scale occur.

In its submission, DPIR states that there is no evidence to suggest that the hydraulic fracturing process can produce measurable earthquakes in areas that do not contain susceptible faults.[178] The statement must, however, be qualified by the comment that Australia does not yet have any seismic risk data covering shale gas operations or a national record of seismic activity below magnitude 4 on the Richter scale.

Seismic activity caused by the reinjection of wastewater into the ground is discussed in greater detail in Chapter 7.

Recommendation 5.8

That to minimise the risk of occurrence of felt seismic events during hydraulic fracturing operations, a traffic light system for measured seismic intensity, similar to that in place in the UK, be implemented.

5.10.2 Subsidence

The development of sinkholes as a result of the hydraulic fracturing process has been noted as a concern of the community. Also of concern was the presence of cavities in karstic terrains (especially around Katherine and Mataranka and which are also known to occur in the Beetaloo Sub-basin) that could possibly result in problems with the placement and anchoring of the conductor casing and the upper sections of any wellbores.

The Panel has not located any scientific information to date about the potential for the development of sinkholes, or diminished well integrity, as the result of drilling in karstic terrain. However, the Panel notes that sinkholes normally occur at shallow depths (tens of metres) in either limestone or evaporite (salt) rock that has been subject to long-term solution by groundwater.

Further, the Panel considers that sinkholes are highly unlikely to occur as a result of hydraulic fracturing because of the large vertical distance between the hydraulic fracturing zone and

174 Drummond 2016; the unit of MW (moment magnitude) is equivalent to the Richter scale magnitude for the small to medium earthquakes referred to here.
175 SHIP 2017.
176 Royal Society Report.
177 UK Government 2017; Wong et al. 2015.
178 DPIR submission 226, p 56.

the surface (several thousand metres), a distance over which the intervening rocks should compensate for any small cavities produced by hydraulic fracturing. In this context, the Panel notes that very little incompressible material is actually removed during the drilling and fracturing process, so there are very few cavities that would contribute to subsidence. This contrasts with CSG operations, where a substantial proportion of the original void volume in the coal seam is removed as produced water, and there is a much greater possibility of subsidence given the closer proximity of the CSG activities to the surface.

The Panel acknowledges, however, the potential for complications associated with drilling in karstic terrain, and the importance of having experienced and licensed drillers conducting drilling operations in such areas.

5.11 Conclusion

In conducting its review, CSIRO notes that many studies of well integrity do not make the distinction between failures of individual barriers and well integrity failures, a distinction that is critical as a full integrity failure (that is, failure of multiple barriers) is required to provide a pathway for contamination of the environment.

CSIRO found overall that the rate of well integrity failures that have the potential to cause environmental contamination is in the order of 0.1%, with several studies finding no well integrity failures. The rate for a single well barrier failure, however, was much higher, in the order of 1-10%. However, there were very few single barrier failures observed for wells constructed to Category 9 or above, and no well integrity failures for those categories. The Amungee NW-1H well that was constructed by Origin in the Beetaloo Sub-basin was of Category 9 standard, with casing cemented to surface along the entire length of the well.

CSIRO found that for shale gas wells abandoned using current practices, if any of the potential leakage pathways were to develop, it was highly unlikely that they would allow large fluid flow rates along the well bore. The small cross-sectional areas and long vertical lengths of the pathways will limit flow. The low permeability of shale gas formations is also a factor mitigating the potential for impacts of loss of well integrity post well abandonment. Pressures within the part of the reservoir accessed by the well will have been depleted by production, and the very low permeability of the shale will prevent gas from other parts of the reservoir migrating to the well.

Even though CSIRO concluded that the potential for serious post abandonment integrity issues is low, the Panel has found that there is very little information available worldwide on the performance of abandoned onshore shale gas wells. The assessment of post abandonment performance is an aspect that requires greater attention by both the regulator and industry. This aspect is the subject of specific recommendations by the Panel.

Overall, the Panel concludes that provided a well is constructed to the high standard required for the particular local geology, and provided that it has passed all of the relevant integrity tests prior to, during, and after hydraulic fracturing, there is a 'low' likelihood of integrity issues. There does, however, need to be a program of regular integrity testing during the decades-long operational life of the well to ensure that if problems do develop, they are detected early and remediated quickly. In particular, the well must pass a rigorous set of integrity tests prior to being decommissioned because once a well has been abandoned, it is difficult to re-enter it.

The nature of chemicals used for hydraulic fracturing is also of concern to the community. However, while there have been more than one million fracture stimulations (fracturing) treatments in North America and more than 1,300 in South Australia's Cooper Basin, there has been no reported evidence of fracturing fluid moving from the fractures at depth to near surface aquifers.

The solids produced by drilling represent a substantial waste stream associated with the production of shale gas. A strategic management issue for any potential onshore shale gas industry in the NT is the question of whether this solid waste should be contained in a purpose-built and engineered centralised facility, or contained and managed on a per well pad basis as is currently the case for the exploration regime.

The possibility of hydraulic fracturing causing earthquakes of sufficient magnitude (2 or greater on the Richter scale) to cause structural damage has been raised. Based on an extensive review of the evidence, the Panel has concluded that this is unlikely to occur as a result of hydraulic fracturing. The only exception is if a fault is activated by the reinjection of fluid. By contrast, there have been many instances of higher magnitude earthquakes resulting from the reinjection of waste water into petroleum reservoirs. These larger earthquakes are often associated with the reactivation of existing faults in the reservoir formation.

Finally, the development of sinkholes as a result of the hydraulic fracturing process has been raised by the community. The Panel considers that the likelihood of sinkholes developing is 'very low' as a result of hydraulic fracturing because of the large vertical distance (several thousand metres) between the hydraulic fracturing zone and the surface, a distance over which the intervening rocks will compensate for any small cavities produced by hydraulic fracturing.