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Report into

The shale gas well life cycle and well integrity

Prepared for the Northern Territory Hydraulic Fracturing Inquiry

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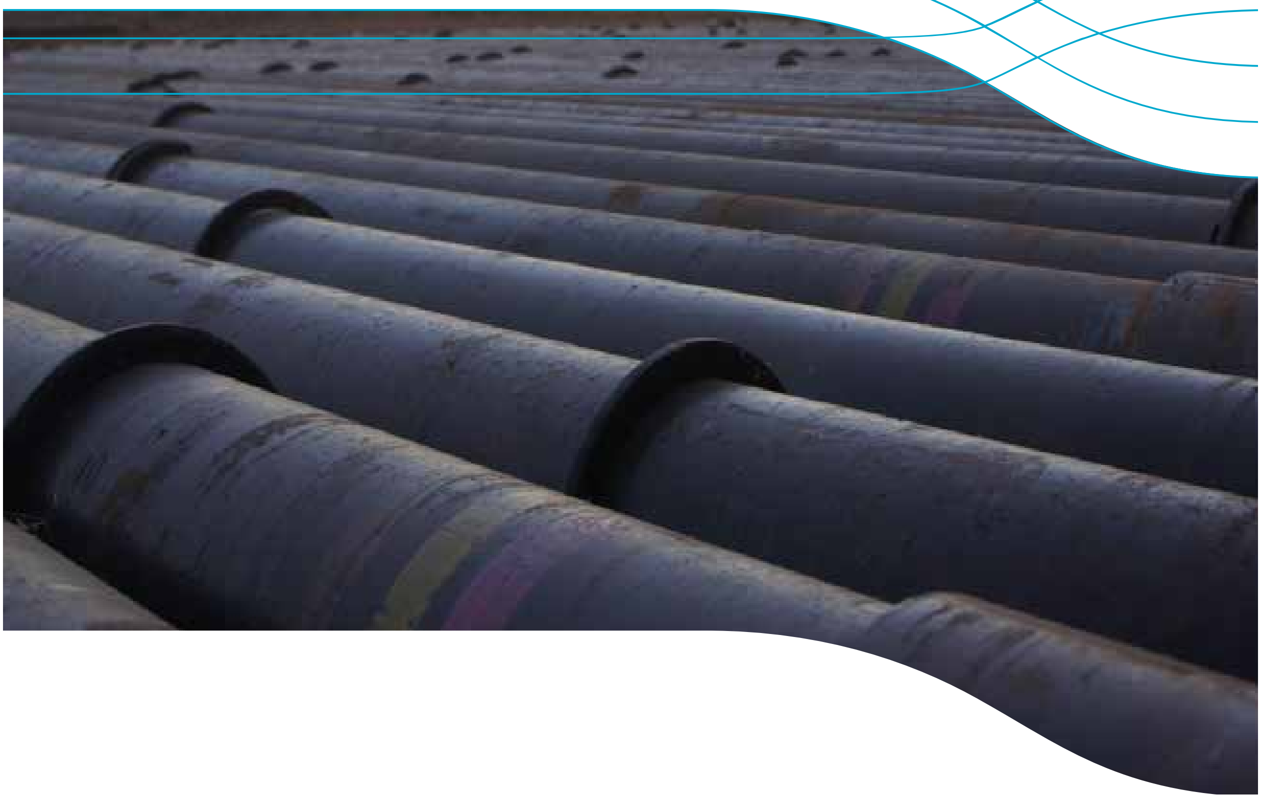

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Executive summary

Shale gas resources are attracting increased attention globally, given their potential as an energy resource. The Northern Territory holds significant shale gas resource potential and, to date, these resources have seen only limited exploration. In December 2016, the Northern Territory Government established the Northern Territory Hydraulic Fracturing Inquiry (**the Inquiry**), an independent scientific inquiry to investigate the environmental, social and economic risks and impacts of hydraulic fracturing of onshore unconventional gas reservoirs and associated activities in the Northern Territory. This report has been prepared for the Inquiry, to provide an overview of the drilling and hydraulic fracturing process employed in the development of shale gas resources. It has a focus on well integrity and the potential for impacts related to well integrity.

This report is based on a review of the literature on well integrity issues and well integrity failure rates for oil and gas wells. The available literature specific to shale gas well integrity failure rates is not extensive; however, the well construction and operation methods used in other oil and gas developments provide an indicator of potential well integrity issues in shale gas development. The well integrity hazards for any shale development will depend on the characteristics of the resource.

The report first provides an overview of concepts around well integrity, and an overview of the drilling life cycle from design to construction, operation and subsequent abandonment, and the associated hydraulic fracturing processes. It then discusses well integrity in more detail, with a review of the potential mechanisms for well integrity issues and the rates of well integrity failure as reported in the literature. Potential pathways for hydraulic fracturing to cause subsurface contamination and to affect well integrity are also discussed. The report outlines the regulatory regime that applies to well integrity and hydraulic fracturing in the Northern Territory, and summarises the regulations in other Australian jurisdictions. It concludes with policy options for managing well integrity risks in the Northern Territory.

Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface. Well integrity is established through the use of barriers that prevent these unintended fluid flows. For shale gas wells, a two-barrier principle is applied, in which at least two independent and verified barriers are in place. Only if both barriers fail will there be a well integrity failure that results in unintended or uncontrolled fluid flow.

The key findings of this study are as follows:

- Well integrity in shale gas wells is a risk that needs active management throughout the well life cycle for the safe, efficient and environmentally sustainable operation of wells.
- The scale of the risk depends on the characteristics of the resource being developed, as for other types of oil and gas wells (shale gas wells are a subcategory of oil and gas well).
- The low permeability and limited overpressures in shale gas resources mean that they are likely to have lower well integrity risks than conventional resources, and this is supported by the limited amount of data available.
- The most plausible pathway for environmental impact over the life of a well is by migration of methane gas up the outside of the well, caused by a loss of integrity of the bond between cement and casing or cement and formation. The rates of gas leakage on a per well basis are likely to be small; however, the cumulative flux of gas from a large number of wells may be significant in terms of greenhouse gas emissions.

- The residual risk is low when risks are actively managed using current leading industry practice based on hazard identification, risk assessment and risk management.

Other findings of this study are as follows:

- Industry and regulators have a focus on maintaining well integrity, and the industry follows several international standards on well integrity management.
- Current leading practice involves the use of well integrity management systems to manage integrity risks across the well life cycle.
- The two-barrier principle is critical to maintaining good well integrity and is standard practice in the industry.
- Gas migration along the outside of the well does not necessarily indicate the movement of other fluids. Methane migration is driven by buoyancy, whereas migration of fluids will require pressure gradients to drive fluid flow.
- Plausible pathways for hydraulic fracturing operations (as opposed to during the rest of the well life cycle) to lead to contamination of shallow aquifers are primarily through impacts on well integrity that may contribute to the migration of fluid along the outside of the well. Casing failures during hydraulic fracturing activities are also plausible, although there is a low likelihood of this occurring in wells that have been properly engineered.
- Catastrophic well integrity failures during shale gas drilling operations are unlikely in a shale gas development because of the low permeability and limited overpressures in shale resources.
- Baseline studies to characterise the environment before shale gas activities commence in an area will provide important data to assist in any future evaluation of possible environmental impacts.
- There has been limited development of onshore gas resources in the Northern Territory; therefore, there is currently a lack of data for well integrity hazard identification and risk assessment. To reduce well integrity risks, it may be useful to have a basin-wide approach to identifying hazards and effective risk management approaches, with collaboration between operators, regulators and other stakeholders, should an onshore gas industry develop. This approach may assist in providing the broader community with transparency about the process for managing well integrity.
- In the Commonwealth, South Australia and Western Australia, the regulations related to well integrity for offshore wells are objective based, and use the ‘as low as reasonable practical’ principle for managing well integrity risks. These jurisdictions have no or limited prescriptive requirements around well construction, although they do have guidelines for well integrity assessment.
- Codes of practice for coal seam gas well construction and abandonment are mandated in New South Wales and Queensland. Queensland also has a code of practice for other petroleum wells. The establishment of a code of practice or guidelines in the Northern Territory will need to balance a prescriptive approach with the ability to adapt as risks are understood and new technologies become available.
- The long-term integrity of shale wells that have been abandoned using current industry practices is not well covered in the literature. The main risk for abandoned wells is gas migration along the outside of the casing. Gas leakage on a per well basis is likely to be small, but the cumulative flux of gas from a large number of wells may be significant in terms of greenhouse gas emissions. Understanding the risks associated with abandoned wells within the context of the Northern Territory’s shale gas resources could lead to the establishment of leading practices, should an onshore gas industry develop.

1 Introduction

This report has been prepared for the Northern Territory Hydraulic Fracturing Inquiry (**the Inquiry**) to provide an overview of the drilling and hydraulic fracturing process employed in the development of shale gas resources. It has a focus on **well integrity**[1] and the potential for **impacts** related to well integrity. During exploration, wells provide access to allow the resource to be characterised, and during production they provide a means for gas to be brought to the surface. As the interface to the subsurface environment, wells are also a possible pathway for unintended release of fluids to the environment, and concerns have been raised about well integrity.[2] Hydraulic fracturing is necessary to allow economic production rates from shale gas resources, because of the low permeability of these resources. The potential for impacts on shallow aquifers from the migration of **hydraulic fracturing fluids** has also been raised as a concern.[3]

The drilling and hydraulic fracturing technologies used in shale gas projects have evolved from those used for conventional petroleum resources, with a great deal of innovation over the past two decades.[4] Drilling for shale gas now typically involves the drilling of multiple wells from a single-well pad, with horizontal extensions increasing the exposure to the target shale formation.[5] To produce shale gas, multiple hydraulic fractures are placed along the horizontal section of the well. The most common hydraulic fracture design in shale gas wells in the United States uses water-based hydraulic fracturing fluids pumped at a high flow rate.[6] The adoption of this technology has been important in the rapid growth of shale gas and oil production in the United States.[7]

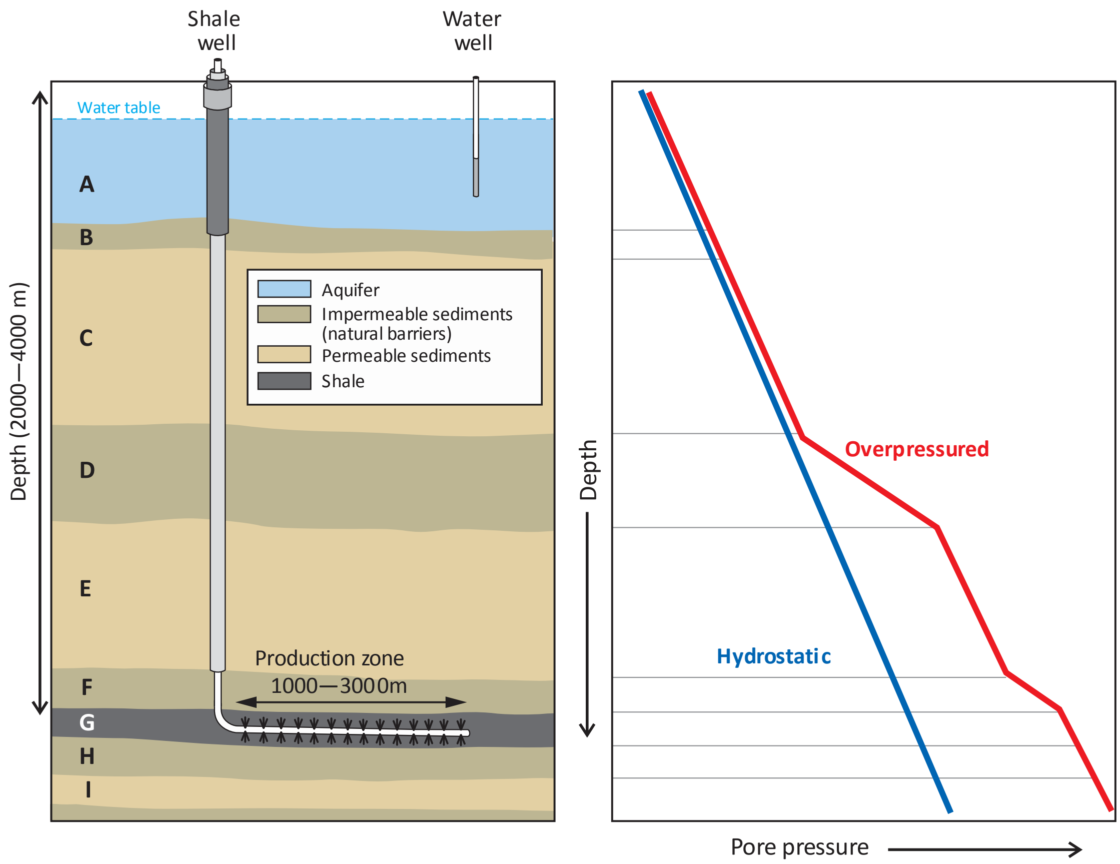
This report first provides an overview of some of the key concepts around well integrity, and of drilling and hydraulic fracturing processes. It then discusses well integrity in more detail, with a review of the potential mechanisms for well integrity issues and the rates of well integrity failure that have been reported in the literature. It also discusses potential pathways for hydraulic fracturing that lead to subsurface contamination. The regulatory regime that applies to well integrity and hydraulic fracturing in the Northern Territory is outlined, together with a summary of regulations in other Australian jurisdictions. The report concludes with a summary of the issues and policy options for managing **risks** related to well integrity.

[1] Terms given in bold in the text are included in the Glossary
[2] Davies et al. 2014; Ingraffea et al. 2014; Jackson 2014.
[3] US EPA Report. Chapter 6.
[4] Golden and Wiseman 2015. p968-974.
[5] Cook et al. 2013. p54-56
[6] Gallegos et al. 2015.
[7] Cook et al. 2013; Golden and Wiseman 2015.

2 Why is well integrity important?

Concerns around well integrity are often raised in regard to shale gas developments. These concerns relate to the potential for the unintended flow of fluid out of, or into, the well, between layers of rock or to the surface via the well. To understand well integrity, it is important to consider how fluids and gases move in the subsurface. **Figure 1** shows a simplified shale gas resource, consisting of the shale layer at the base, with overlying layers of various sedimentary rocks referred to as the **overburden.** This overburden will include layers of different **permeability**; broadly the layers can be classified as permeable (which allow fluid to flow through them) or impermeable (which form a barrier to fluid movement). Some of the permeable layers may be **aquifers**, containing water that is used for agriculture or domestic purposes, whereas others may contain salty water. Hydrocarbons (oil or gas) may also be present in some rock layers.

Figure 1: Simplified shale gas resource. Rock layers A-F are overburden that cover the shale resource (layer G). The graph on the right 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 layers D and F trapping higher pressures below them. Not to scale.



Subsurface vertical water flow

The pressure of the fluids in the rock is called the **pore pressure**, and at hydrostatic pressure, the pore pressure is equal to the weight of the column of fluid above it. The pore pressure increases with depth, as it does in any body of water. When water in rock layers is at hydrostatic pressure, there is no driving force for the water to flow vertically.

In some geological settings, the pore pressure is higher than the hydrostatic pressure. These **overpressures** can occur when there is an increase in the amount of fluid or gas in the rock, or when there are changes to the rock such that the amount of pore space is reduced. If the fluid cannot escape, the result is an increase in pore pressure. Overpressures can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure. In **Figure 1**, layer A contains an aquifer that is connected to the surface. Overpressures cannot form in this layer because the pressure can escape at the surface. The pore pressures in layer E are overpressured, as shown in the graph in **Figure 1**, but the fluid and pressures are held in place by layer D, which is impermeable.

If a well is drilled into a water-bearing layer that is at hydrostatic pressure (layers A, B and C in **Figure 1**), water would only flow up the well with the aid of a pump. This scenario is analogous to drinking a glass of water through a straw – suction has to be applied. If a well is drilled into an overpressured layer (layer E in **Figure 1**), the water will flow up the well unassisted. A common example of this scenario is the artesian water wells drilled into the Great Artesian Basin.

Fluids will not move in the subsurface unless there is a driving force, so an overpressure zone would be required for a fluid to move unassisted vertically up the well.

Subsurface vertical gas flow

Natural gas is predominantly methane, and has a much lower density than water; this buoyancy will drive natural gas to move upwards through the rock unless there is an impermeable barrier in place. Gas resources can only exist if the gas is trapped in the subsurface, otherwise it would have leaked out through geological time. To extract the gas, a well must be drilled to provide a pathway for the gas to flow to the surface. Gas can flow under its own buoyancy, and any overpressure will increase the rate of flow.

Rate of fluid and gas flow

The rate at which fluids or gas move in the subsurface is affected by the size of the flow pathway. The larger the pathway, the greater the rate of flow for a given driving force (overpressure or buoyancy). Friction and surface roughness of the pathway reduce the flow rate; therefore, fluid and gas flow rate will be lower over longer pathways. Another factor is the size of the **reservoir** of fluid or gas, and the permeability within that reservoir. For example, the Great Artesian Basin is a large reservoir with high permeability, and wells drilled into this reservoir have had artesian flows for decades. In contrast, in a small reservoir, the pressures would be quickly depleted and flows would decline. Similarly, in a reservoir with low permeability, the effective fluid or gas flow would be restricted and pressures would drop quickly. Shale gas reservoirs have low permeability by definition, which is why **hydraulic fracturing** is required. The hydraulic fractures increase the volume of the reservoir accessed by a well (the fractures are extensions of the well for practical purposes), overcoming the low permeability.

The role of drilling fluids

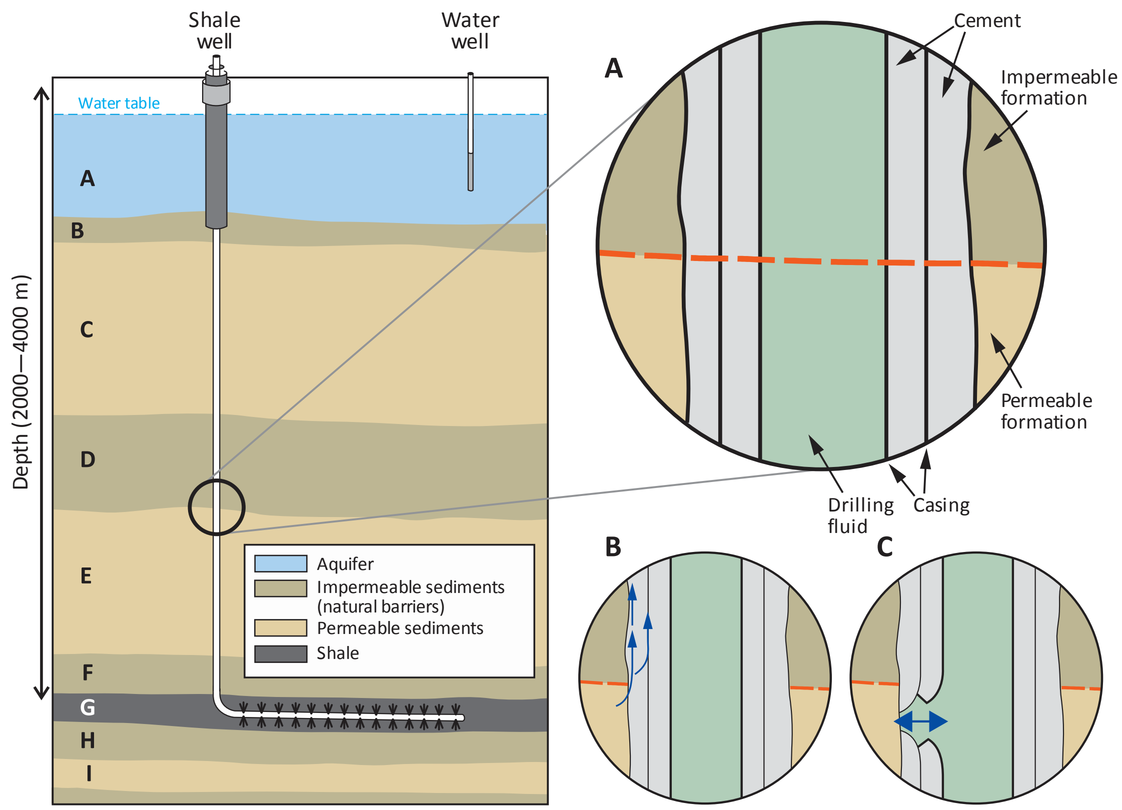
Drilling fluids are usually designed to have a density that balances the pore pressure in the surrounding rock, to prevent formation fluid from entering the well and drilling fluid from being lost to the formation. Drilling fluids also need to lift drill cuttings from the well, prevent **borehole** breakout and lubricate the drill bit. If the drilling fluid density results in pressures greater than the formation pressure, drilling fluid may be lost to the formation. Faults and fractures may also result in losses of drilling fluid. These possible scenarios are well known and are readily identified during drilling operations. A range of engineering practices can be used to manage these losses, including changing the drilling fluid density, using additives that prevent losses and setting **casing** across loss zones.

Well barriers

When a well is drilled, well integrity is established by maintaining the integrity of the natural barriers (the impermeable rock layers) through which the well is drilled. The primary methods of creating well integrity are cementing steel casing into the well, as shown in Figure 2, and controlling the density and pressure of fluids (including drilling fluids during drilling operations) or gas within the well. Problems with well integrity can generally be considered in two broad categories:

- unintended flow of fluids or gases between rock layers or to the surface along the outside of the well (see **Figure 2B**); and
- 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 (see **Figure 2C**).

Figure 2: Shale gas wells cut through geological layers that form barriers to vertical flow. The casing, cement and management of pressures within the well reinstate this barrier (red dashed line in A). Well integrity problems can occur when the well becomes a pathway for vertical movement or gas or fluid (B), or when the well is breached, allowing fluid to flow in to or out of the well (C). Not to scale.



When considering fluid movement, overpressures contribute significantly to well integrity issues and their consequences. However, high overpressures that would drive vertical fluid movement are not a common feature of shale resources, and the limited data collected in the Beetaloo Basin indicates that this basin has low overpressures.[8] In 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 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 could flow up a pathway

[8] Close et al. 2016.

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will be limited by the aperture of the opening through which it flows. Where the **annulus** between the well casing and the rock is cemented, the size of any opening will be limited.

A loss of well control can result in the unintended flow of fluid into or out of a well. Where there are high overpressures, the risk of fluid or gas flow into the well is higher. An inrush of gas or **formation fluid** into the well can lead to a well **blowout** at the surface. Large overpressures can be a factor in conventional oil and gas resources, and were a contributing factor to the blowout of the Macondo well that led to the loss of the Deepwater Horizon drilling rig.[9] The Macondo well was drilled offshore in water over 1,500 m deep. The well extended around 4,000 m below the sea floor, where it intersected four distinct hydrocarbon reservoirs. These reservoirs were highly overpressured, with pore pressures close to exceeding the tensile strength of the rock, and contained large volumes of gas and oil. The eventual blowout of the Macondo well is believed to have been caused by a chain of failures, starting with a failure of the cement around the casing, followed by a failure of the **blowout prevention** (**BOP**) system and other secondary safety systems. In contrast, shale gas wells are drilled onshore and into resources at a relatively shallow depth below the surface (2,000-4,000 m). High overpressures are uncommon in shale gas resources, and the low permeability in shale resources will limit the volume of any inrush into the well, meaning that blowouts are unlikely.[10] The operational complexity of onshore shale gas wells is also lower than for offshore drilling in conventional reservoirs, particularly those with high overpressures. This comparison highlights the importance of the geology and characteristics such as pore pressure, permeability and reservoir volume in determining the potential consequences of a failure of well integrity.

Hydraulic fracturing fluid movement

Hydraulic fracturing fluid will migrate into the formation when fluid pressures are higher than the pore pressures in the surrounding rock. During hydraulic fracturing operations, a specific zone of the surrounding rock formation is exposed to the high-pressure hydraulic fracturing fluid in order to propagate hydraulic fracture into the formation. The design of the well controls where the hydraulic fracturing fluid can enter the formation. If the well integrity is compromised, hydraulic fracturing fluids may breach the well and flow into other rock layers. Designing a well to withstand hydraulic fracturing pressures is a routine engineering task, and the designs typically incorporate multiple barriers; also, **pressure testing** of the well before hydraulic fracturing ensures that the well is strong enough to withstand hydraulic fracturing pressures.

Hydraulic fracturing injects fluid under pressure into the reservoir rock. Some of this fluid will hold open the fractures, and the rest will flow into the pore space in the reservoir rock. When the hydraulic fracturing operation is complete, the fluid pressures will dissipate quickly and a portion of the injected hydraulic fracturing fluid will flow back up the well. Some hydraulic fracturing fluid will remain in the pores of the reservoir rock layer due to the low permeability. Migration of the hydraulic fracturing fluid left behind in the pore space of the reservoir rock is governed by the same processes as the migration of other pore fluids; therefore, it is unlikely that the fluid will be strongly driven to flow vertically between rock layers.

Summary of the importance of well integrity

This discussion highlights some of the basic geologic and engineering factors that influence well integrity, and the impact of these factors in shale gas resources. High overpressures are uncommon in

[9] National Academy of Sciences, 2012.
[10] Royal Society & Royal Academy of Engineering 2012. p25

shale gas resources, and the low permeabilities in these resources will limit the potential for a blowout and the potential drive for cross formation flow. In addition, the low permeabilities will continue to influence the impacts of well integrity after the well has been abandoned. Pressures within the reservoir will be depleted by production. Restoration of pore pressure in the reservoir is likely to be slow because the low permeability will prevent migration of any high-pressure fluids from outside the reservoir, and processes that might increase pressures from within the shale are subject to a geological timescale. However, some gas will remain in the reservoir and its buoyancy will continue to provide drive for upward flow, should pathways be available.

3 Well life cycle

All wells follow a similar life cycle, regardless of their purpose, with some variations in their design and operational aspects. The well life cycle, as outlined in *ISO 16530-1 Petroleum and natural gas industries - Well integrity - Part 1: Life cycle governance* (**ISO 16530-1**), has the following phases:[11]

- basis of design phase;
- design phase;
- construction phase;
- operational phase;
- intervention phase; and
- abandonment phase.

Figure 1 shows the basic layout of a shale gas well and identifies its key components. The layout and components of a well will vary according to its purpose in the local geology. It is impossible to draw a shale gas well in a way that shows how narrow the well is compared to its length. The diameter of a well is only about 15-25 cm, whereas the length is several kilometres. A useful way of visualising this ratio of diameter to length is to think of the edge marking (around 10-12 cm wide) on a several kilometre stretch of highway.

3.1 Basis of design phase

The basis of well design phase is where the objectives of the well are set and the full life cycle operational requirements are determined, to allow for detailed design of the well in the next phase. Some of the information that is required at this phase includes:[12]

- the location;
- targets – formations and depths;
- well type (that is, **exploration**, production or monitoring);
- well subsurface architecture (vertical, deviated or horizontal);
- geological information, including expected formations, aquifers, faulting and temperatures;
- geomechanical information, including pore pressures, rock strength, in situ **stresses**, **porosity**, permeability and temperatures;
- for an exploration well, data acquisition requirements;
- for a production well, production parameters such as production rates, the composition of the fluids and gasses that will be produced, and the stimulation and testing strategies that will be used;
- potential for planned re-completion or conversion of the well for other purposes (converting an exploration well to a monitor well, for example); and
- the expected operating life of the well.

[11] ISO 16530-1:2017.
[12] ISO 16530-1:2017.

The geology of the resource and the overlying strata that must be drilled through to reach it are important because they determine the depth, thickness and gas content of the target shale horizon. Although shale resources are typically made up of flat lying layers of rock, geological features such as folds and faults are important in determining the geometry of the resource. Igneous intrusions may also cut through the resource, and the design of the well trajectory will need to take these features into account.

Geomechanical properties are important because they describe how rock will respond mechanically (deform or break) as it is drilled through. An open well will fail if the stress concentrations around its circumference exceed the strength of the rock.[13] Geomechanical parameters such as in situ stress, rock strength and pore pressures are important for the design of the casing in the well. These parameters are also important for hydraulic fracture design.

Overpressures in formation fluids are an important consideration for well design and well integrity. [14] If the pore pressure is at the hydrostatic gradient, there is no driving force for fluids to move vertically between layers of rock at different depths, or to the surface. If the pore pressures are above the hydrostatic gradient, they are said to be overpressured and those pressures can drive the flow of fluids vertically between formations to the surface, should a pathway be available. A well with good integrity will be able to control these overpressures. Overpressures develop naturally as a result of a range of mechanisms through geological time, and low to moderate overpressures are present in many shale resources, including the Beetaloo Basin in the Northern Territory.[15] Gas and oil can move vertically owing to their buoyancy and expansion, even without overpressure, but water cannot move vertically without a driving force.

These geological, geomechanical and operational considerations are all important for well integrity. These factors need to be taken into account so that the design of the well reduces risks to its integrity.

3.2 Design phase

In this phase, all aspects of the well are designed in detail, taking into account the overall life cycle of the well and all future operations, through to its eventual abandonment. The design is based on a detailed analysis of data and requirements collected during the previous phase, and includes the following aspects:[16]

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

The design of the casing, cementing and completion are important for long-term well integrity. Casing is steel piping that provides a pressure tight conduit between the shale gas resource and the surface.[17]

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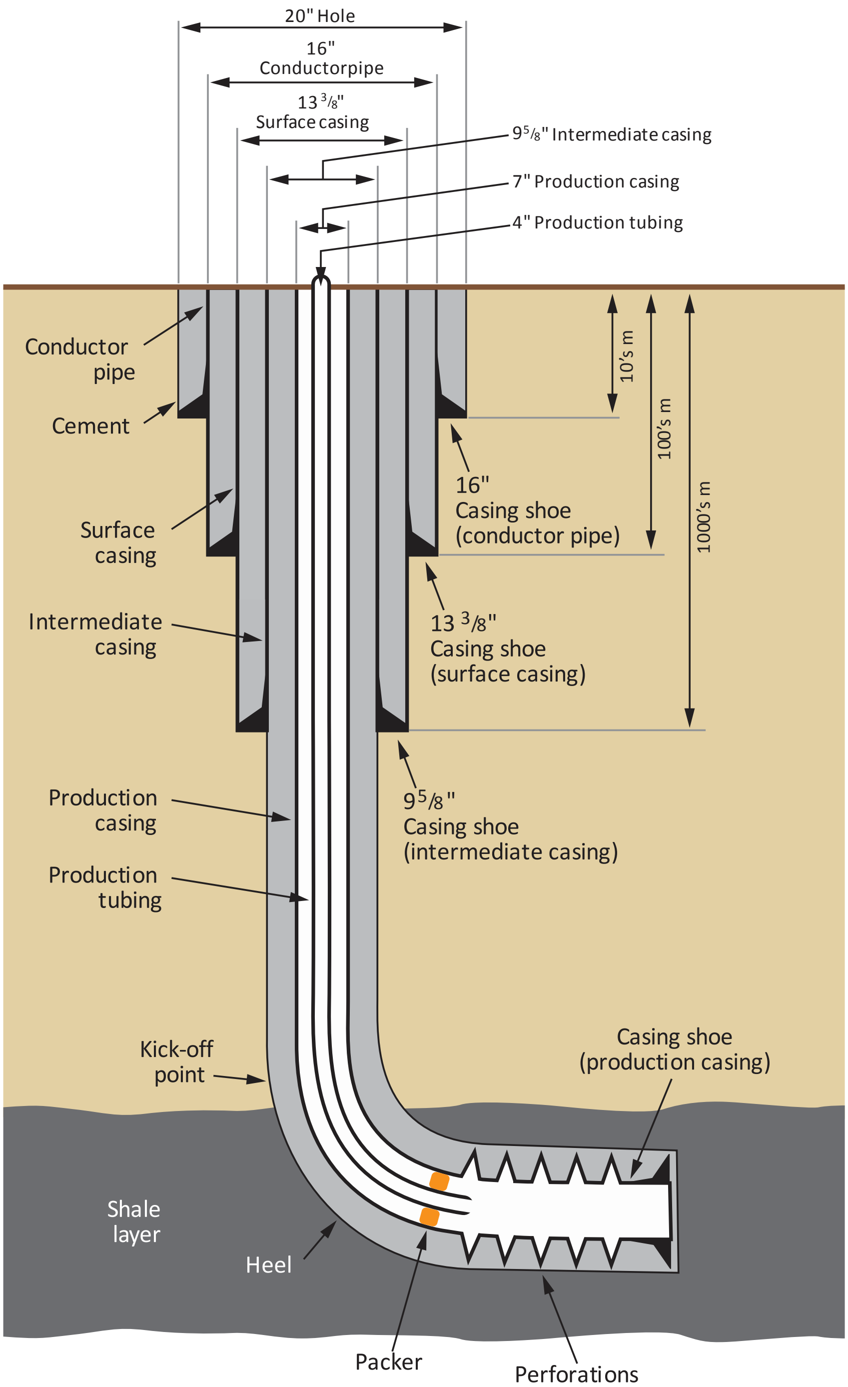
[13] Zoback 2007. p3 and chapters 6 to 9.
[14] Zoback 2007. p3 and chapters 6 to 9.
[15] Close et al. 2016; Jarvie 2014; US EIA 2013.
[16] ISO 16530-1:2017.
[17] Hossain and Al-Majed 2015. p433-501

Wellbore casing is a highly engineered product that is designed to cope with anticipated wellbore conditions. International standards cover the manufacture, testing, engineering specification, mechanical properties and performance of the casing.[18] The casing prevents the unintended flow of drilling and hydraulic fracturing fluids out of the well, keeps the well open through weak or broken rock layers, and prevents formation fluids from entering the well and from moving between layers of rock via the well.

Figure 3: General layout of casing in a shale gas well. Casing sizes are specified in imperial units. Not to scale (width is significantly exaggerated).



Casing/hole sizes

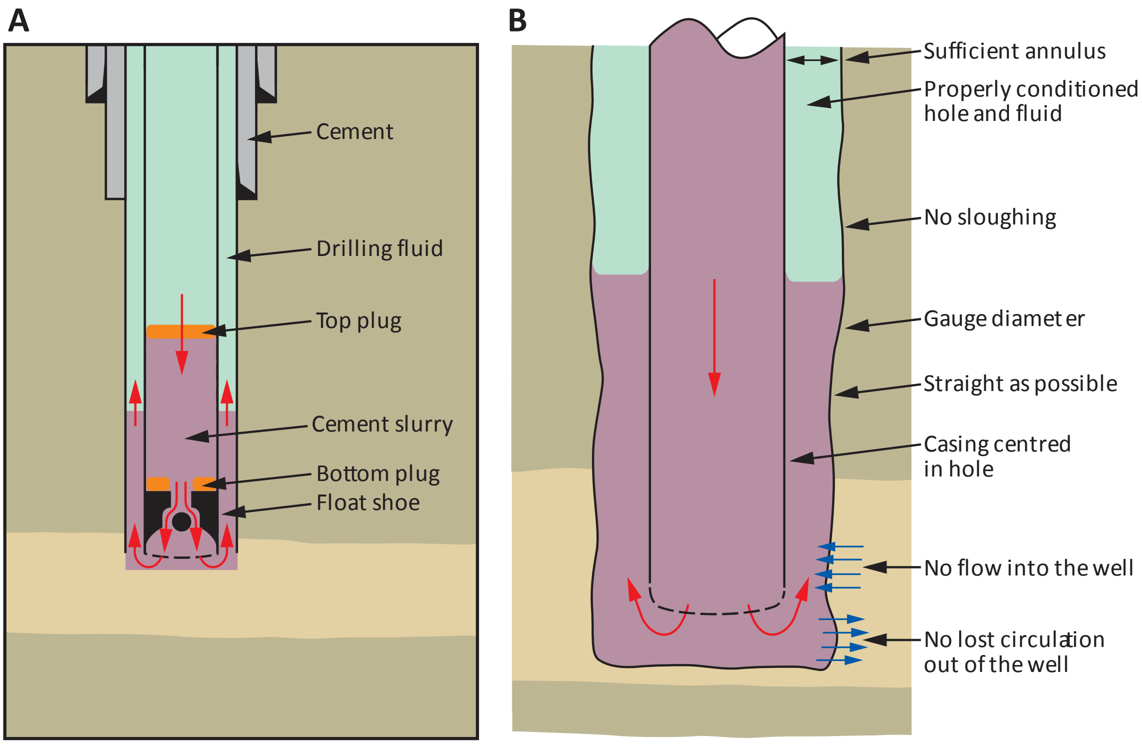
Inches	Centimetres
20	50.8
16	40.6
13 3⁄8	34.0
9 5⁄8	24.4
7	17.8
4	10.2

[18] ISO 11960:2014.

Wells are drilled in stages, with each stage cased before drilling proceeds to the next stage, using a smaller diameter drill bit. **Figure 3** shows the general layout and nomenclature for casing used in shale gas wells, indicating that the diameter of the well decreases with depth, as successive casing telescopes inside the previous **casing strings**. The design of casing for a well will need to take into account the depths of layers of rock or aquifers that need to be isolated from each other, the corrosive nature of fluids or gases (such as hydrogen sulphide or carbon dioxide) that may be encountered, the stresses that the casing will be subjected to and the operational requirements of the well. The casing layout, casing material and wall thickness are all parameters that can be varied.

Without cementing, the casing alone is not sufficient to ensure wellbore stability. Therefore, the casing is cemented into the well (**Figure 3**), to provide strength to the well and a seal between the casing and the surrounding rock.[19]

Figure 4: The process for cementing casing into a well. The cement is pumped down into the centre of the well and returns up the outside of the well (A). The well requirements for effective cementing are shown in (B). Not to scale. Modified from Smith.[20]



During the cementing process, a cement slurry is pumped down the centre of the well, and flows up the annulus between the rock formation and the most recently placed casing (**Figure 4**). The cement works with the casing to mechanically couple it to the surrounding rock, creating a hydraulic seal and protecting the casing.[21] Shale gas well cements are usually a Portland cement (of slightly different chemical composition to regular Portland cement) mixed with water and other additives. The additives modify certain properties of the cement, such as setting time, viscosity, density and permeability to different fluids. Well cements are designed, tested and prepared using established procedures to meet

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[19] Taoutaou 2010.
[20] Smith 1990.
[21] Hossain and Al-Majed 2015. p503-570

relevant specifications, and they have negligible permeability to formation fluids when cured.[22] The casing and cement work together and are critical to well integrity.

In designing the oilfield cementing process, drilling engineers consider factors such as the depth and design of the well, and the properties of the pore fluids and surrounding rock layers. The cementing process is undertaken in a series of steps that are designed to clean and prepare the well for cement, prevent the cement slurry from contamination with drilling fluid (also known as **drilling mud**) and ensure that the cement slurry is positioned at the intended vertical well location.

Various standards cover the design of wells, the specification of materials and equipment used in their construction, and well operations. As at June 2016, the International Association of Oil and Gas Producers listed over 150 primary standards related to well construction and well operations.[23] Some of these standards are mandatory in various jurisdictions; however, they are mostly used for quality control for operations, and the provision of services and materials in the industry.

3.3 Construction phase

The well construction phase involves drilling and completion of the well in accordance with the design. A focus during this phase is managing the risks associated with drilling and maintaining well integrity.[24] Well control refers to the prevention of 'kicks', which are uncontrolled flows of formation fluids or gases into the wellbore that can reach the surface.[25] A severe kick can lead to a blowout, which is the uncontrolled escape of fluid from the well.

Drilling fluids are an essential component of drilling operations, and are distinct from the hydraulic fracturing fluids used during well stimulation (see Section 4). [26] These fluids provide cooling and lubrication to the drill bit and drill string, lift drill cuttings from the well and are a component of well control. The density of the drilling fluid is increased by the use of additives to counteract any overpressures in the formation, preventing kicks and helping to maintain wellbore stability in uncased sections of the well. If the density of the drilling fluid is too high, drilling fluid may be lost in layers of rock. Additives that create a low-permeability skin on the wellbore can be used to limit these losses.

Casing is installed and cemented in place in a number of stages during the construction phase, as shown in **Figure 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 either the design depth or a depth where a casing string is required, a steel casing string is run into the borehole and cemented (**Figure 3** and **Figure 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 well construction is complete.

In each stage, the well is prepared (essentially, cleaned by the circulation of drilling fluid) and cement is then 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 depends on both the cement slurry design and several other aspects of the well cementing process; for example, preparation of the wellbore, and the condition and centralisation of the casing. Ideally, the wellbore and casing would be prepared for cementing as follows (**Figure 4B**):

- the wellbore diameter should be close to the drill bit size (known as the gauge);

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[22] ISO 10426-1:2009.
[23] IOGP 2016.
[24] ISO 16530-1:2017.
[25] Hossain and Al-Majed 2015. p205
[26] Hossain and Al-Majed 2015. p73-139

- the surface of the wellbore should be smooth;
- during drilling, breakouts or **washouts** of the surrounding rock should have been minimised by good design of the drilling mud;
- there should be no formation fluid influx into the wellbore or major loss of drilling mud to the surrounding rock;
- the casing should be centralised, with a sufficiently wide annulus surrounding the casing to allow cement flow; and
- the drilling mud in the hole should be properly conditioned to remove pieces of rock that may slough off the walls of the well.

During the construction phase, components of the well that contribute to the well's integrity are tested to verify that they are performing as designed. Verification is an important element of well integrity management.[27] The integrity of well casing and cement can be tested by pressurising the well, to verify that it can hold the pressures that it may be exposed to over its life. A variety of downhole logging tools can be used to measure the state of the casing and the integrity of the bond between the casing, cement and rock.

For production wells or wells used for formation testing, hydraulic fracturing (also known as well stimulation) activities are undertaken as part of the construction phase. The hydraulic fracturing process itself is described in Section 4.

The final activity in the construction phase is the 'completion' of the well, preparing it for the production of gas.[28] Completion involves the installation of hardware in the well to allow the safe and efficient production of gas from the well at a controlled rate, and many different completion technologies are available. If the well was drilled for other purposes, or if the well is to be suspended, the completion will be designed accordingly. For example, instruments such as pressure meters or temperature sensors may be installed in a monitoring well during the construction phase.

3.4 Operational phase

For production wells, the operational phase will have the longest duration, with some wells producing hydrocarbons for decades. During this phase, the main activities are monitoring the well's integrity and performance, and maintenance. Abnormal pressures in the annulus between casing strings can indicate integrity issues, as can changes in production rates. Wireline logging, in which measurement tools are lowered down the well on a wireline, is generally the only means of checking the integrity of casing and cement down the well. Observations from a sample of wells can be used to indicate the integrity of wells across a field.[29]

3.5 Intervention phase

In some cases a well must be re-entered to perform maintenance, repairs or replacement of components; for surveillance; or to increase productivity.[30] Such interventions are also referred to as '**workover**'. Interventions can be critical to maintaining well integrity, and a range of technologies are

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[27] ISO 16530-1:2017; NORSOK D-010.
[28] Hossain and Al-Majed 2015. p679-735
[29] ISO 16530-1:2017. p53
[30] ISO 16530-1:2017.

available for repairing casing and cement.[31] Production wells may be hydraulically re-fractured to extend their production, and the design of such activities needs to be commensurate with the design of the well and its current condition, allowing for any corrosion or other deterioration.

3.6 Abandonment phase

The **abandonment** phase is the final phase in the well life cycle; in this phase, the wells are decommissioned, **plugged and abandoned**. The goal of plugging and abandoning the well is to ensure the integrity of the well in perpetuity, effectively re-establishing the natural barriers formed by the impermeable rock layers that were drilled through to reach the resource.[32] Once a well has been abandoned, there is little prospect of re-entering the well for any purpose. Monitoring may be conducted after the well has been abandoned, to confirm that **plugs** have been properly set in the well. The well's ongoing integrity should not be dependent on long-term monitoring,[33] although such monitoring may be conducted to confirm the effectiveness of abandonment practices. 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.

The method of plugging and abandoning a well involves confirming the well's integrity to ensure that there will be no movement of fluid into or out of the well, and placing barriers in the well to prevent the vertical movement of fluids between rock layers. A schematic of an abandoned well is shown in **Figure 5**. The plugs typically comprise cement with mechanical plugs or retainers. To provide long-term integrity, the cement (or other barrier material) must:[35]

- 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.

The design of well abandonment must be considered during the design phase of the well.[36] For example, the casing material that will be left in the well must be compatible with the objectives of abandonment.

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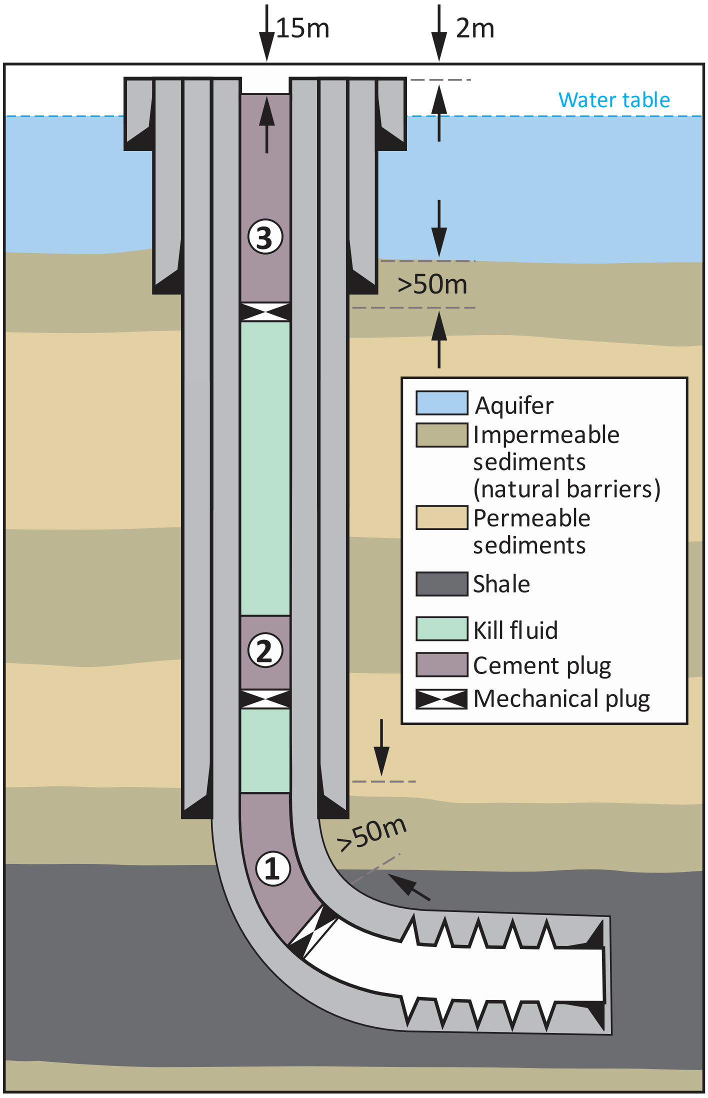
[31] Ansari et al. 2017; Durongwattana et al. 2012; Roth et al. 2008.
[32] ISO 16530-1:2017; Kiran et al. 2017; NORSOK D-010.
[33] ISO 16530-1:2017.
[34] ISO 16530-1:2017.
[35] NORSOK D-010. p96
[36] ISO 16530-1:2017.

Figure 5: An abandoned well, showing the cement plugs that are placed in the well to prevent vertical flow of fluids. Numbers indicate order of placement of the cement plugs. Not to scale.



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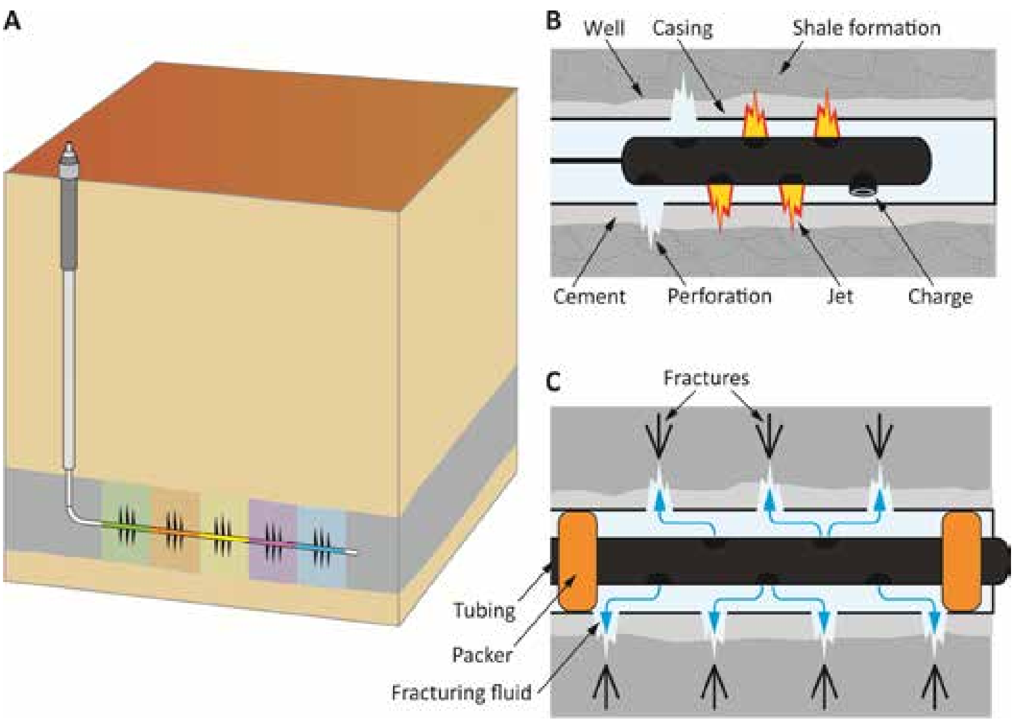
4 Hydraulic fracturing

Hydraulic fracturing is a stimulation technique that is used to increase the production of oil and gas from **unconventional resources** such as oil shales, by the injection of a hydraulic fracturing fluid at high pressure into a cased wellbore. Hydraulic fracturing of a shale gas or shale oil is usually conducted over several intervals (called 'hydraulic fracture stages') along the **production zone** of the well (**Figure 6**). Hydraulic fracturing of each stage treats a discrete volume of the reservoir. This staged approach allows for more control of the hydraulic fracturing process.

It is generally not possible to hydraulically fracture the whole well in one step. Most hydraulic fracturing treatments in shale oil and gas wells take place in the relatively long (up to several km and usually at least 1-2 km long) horizontal or nearly horizontal section of the well that follows the rock layers that contain the most concentrated hydrocarbon resource, and that has mechanical properties that allow for successful fracture treatment. Although vertical wells may be fractured for testing purposes, it is now uncommon to use a large number of vertical production wells to exploit shale gas or tight gas resources, because vertical wells cannot access a large enough volume of the reservoir. The number of fracture stages in a single well has increased over time in unconventional fields in North America. Moreover, a single well may have more than one horizontal branch or 'lateral', and each of these can have a large number of fracture stages. In 2009, 10-12 stages would have been considered typical, with spacing of around 200 m; in contrast, in 2017, it is common for 40-100 fracture stages to be placed in a single lateral, with spacing of about 15-30 m between clusters.

Figure 6: Hydraulic fracture stages. Hydraulic fracturing is typically conducted in stages; each coloured zone in (A) shows a different stage. For each stage, the casing must be perforated (B) to allow the hydraulic fracturing fluid to access the shale formation. 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). Various technologies can be used for staged hydraulic fracturing. Not to scale.



The hydraulic fracturing fluid is predominantly a mixture of water, **proppant** (usually sand) and a small percentage of chemical additives (typically less than 1%). 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. Because 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, resulting in 'hydraulic' fractures. The direction in which the hydraulic fracture propagates depends on the orientation of in situ stress in the reservoir, with growth mainly occurring in a direction perpendicular to the minimal **principal stress**. At larger depths, the overburden (vertical) stress due to the weight of the overlying soil or rock is typically greater than the horizontal stress, implying that hydraulic fractures are usually vertically orientated. Once the hydraulic fracture has initiated, further propagation is controlled by the fluid flow. Some of the hydraulic fracturing fluid drives hydraulic fracture growth; the rest is injected or lost 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 therefore 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 simulation, 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; this is known as the '**well pad**'. As the hydraulic fracture propagates into the reservoir, proppant is added to the hydraulic fracture fluid in such a way that the correct proppant concentration along the hydraulic fracture is reached at the end of the treatment. Finally, the wellbore is flushed to remove any residual proppant, leaving behind a proppant-filled fracture that acts as a conductive channel through which oil and gas can flow into the wellbore.

After hydraulic fracturing treatment is complete, a portion of the hydraulic fracturing fluid will flow out of the wellbore in a process known as '**flowback**'. The experience in the United States is that the amount of hydraulic fracturing fluid that returns to the surface as flowback water from shale gas reservoirs is typically 10-30%.[37]

The advent of **horizontal drilling**, which exposes the wellbore to a larger part of the reservoir formation, has made it possible to extract oil and gas from reservoirs that were previously considered uneconomical. In the United States in 2015, it is estimated that almost 50% of crude oil production and 70% of natural gas production was from hydraulically fractured wells.[38] Hydraulic fracturing uses a significant volume of water, with a typical shale gas well consuming 13-24 million litres of water during stimulation activities. The Barnett Shale in the United States, for example, used about 243 billion litres of water over its production history, and hydraulic fracturing as a whole used about 116 billion litres water annually in the period 2012-2014. [39] More than 50 million tonnes of proppant (90% is silica sand) are used in the US annually for hydraulic fracturing operations. In 2017, about 4000 tonnes per well is typically used. The trend in the United States is for faster drilling, more hydraulic fractures per well and more wells drilled from each well pad.[40] However, any eventual shale gas well and hydraulic fracture designs in the Northern Territory would be governed by a number of factors including specific geology, available technology, well location and market forces.

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[37] US EPA Report.
[38] US EIA 2016a; US EIA 2016c.
[39] US EPA Report.
[40] US EIA 2016b.

5 Well integrity

Well integrity is a fundamentally important aspect of well operations throughout the life cycle of a well. Maintaining well integrity is critical for the safe and effective operation of wells, and to protect the environment.

Well integrity is defined in several international standards, recommended practices and guidelines:

- Norsok Standard D-010 *Well integrity in drilling and well operations* (**Norsok D-010**) defines well integrity as the "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well*".[41]
- The Norsok D-010 definition is also used by Oil & Gas UK's *Well life cycle integrity guidelines*.[42]
- **ISO 16530:1 2017** defines well integrity as "*containment and prevention of the escape of fluids to subterranean formations or surface*".[43]
- *Hydraulic fracturing – well integrity and fracture containment, ANSI/API recommended practice 100-1* (**API 100-1**) defines well integrity for onshore wells that will be hydraulically fractured as "*The quality or condition of a well in being structurally sound with competent pressure seals (barriers) by application of technical, operational, and organizational solutions that reduce the risk of unintended subsurface movement or uncontrolled release of formation fluid*".[44]

API 100-1 further describes well integrity as *"the design and installation of well equipment to a standard that:*

- *protects and isolates useable quality groundwater,*
- *delivers and executes a hydraulic fracture treatment, and*
- *contains and isolates the produced fluids"*. [45]

ISO 16530:1 2017 also provides a more complete description of well integrity:

> *"Well integrity refers to maintaining full control of fluids 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."*

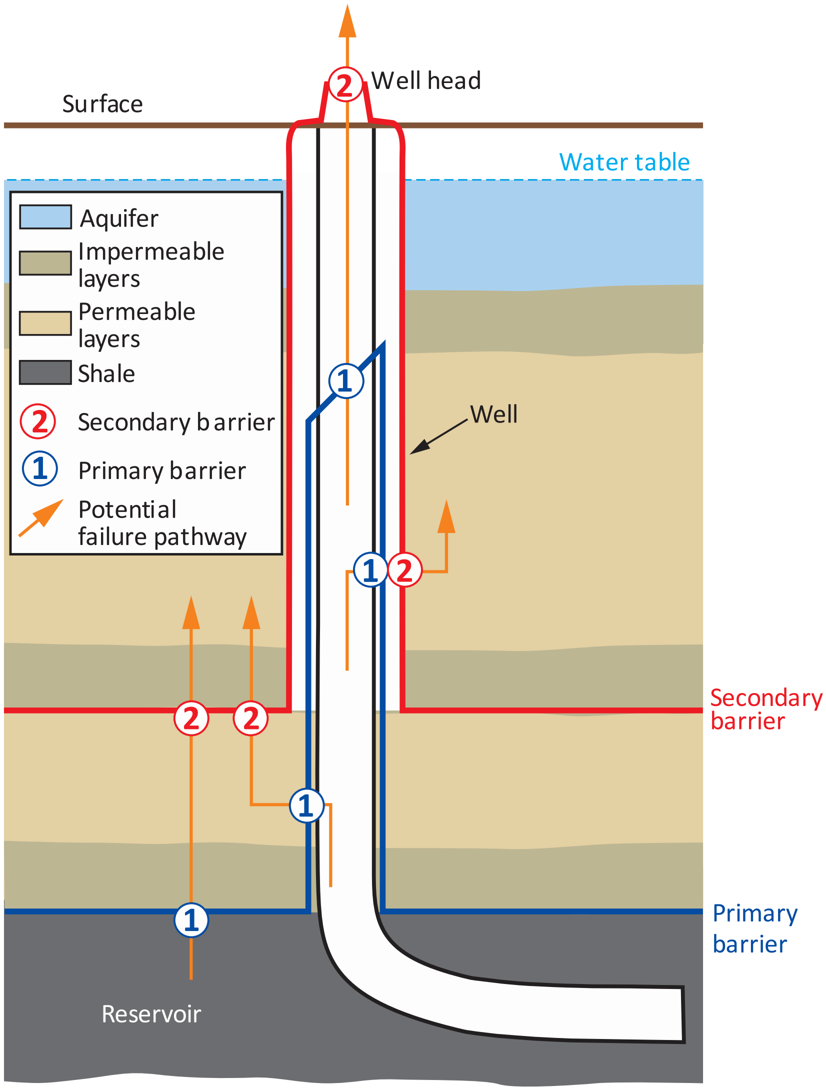
This definition is particularly useful because it introduces the concept of **well barriers**. A fundamental concept in well integrity, well barriers are defined in ISO 16530:1 2017 as a "*system of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well*".[46] Well barriers normally comprise several components and practices that work together to contain fluids; they include physical or hardware barriers, operational barriers, human barriers and administrative barriers.

Physical and hardware barriers are the components that are most tangible. They include impermeable formations, drilling fluids, casing cement, casing strings, **packers**, **well heads** and valves, and blowout

[41] NORSOK D-010.
[42] Oil & Gas UK 2016.
[43] ISO 16530-1:2017.
[44] API RP 100-1.
[45] API RP 100-1.
[46] ISO 16530-1:2017.

preventers. **Figure 7** shows the basic principles of the barrier concept, with the elements combining to form a "top hat" barrier that separates fluid in the reservoir and the well from the external environment and the surface. In this figure there are two barriers: a primary barrier in blue and a secondary barrier in red. The use of a two-barrier system, with two independently verifiable well barriers, is common practice in the industry. The second barrier gives a level of redundancy, providing protection should the primary barrier be compromised.

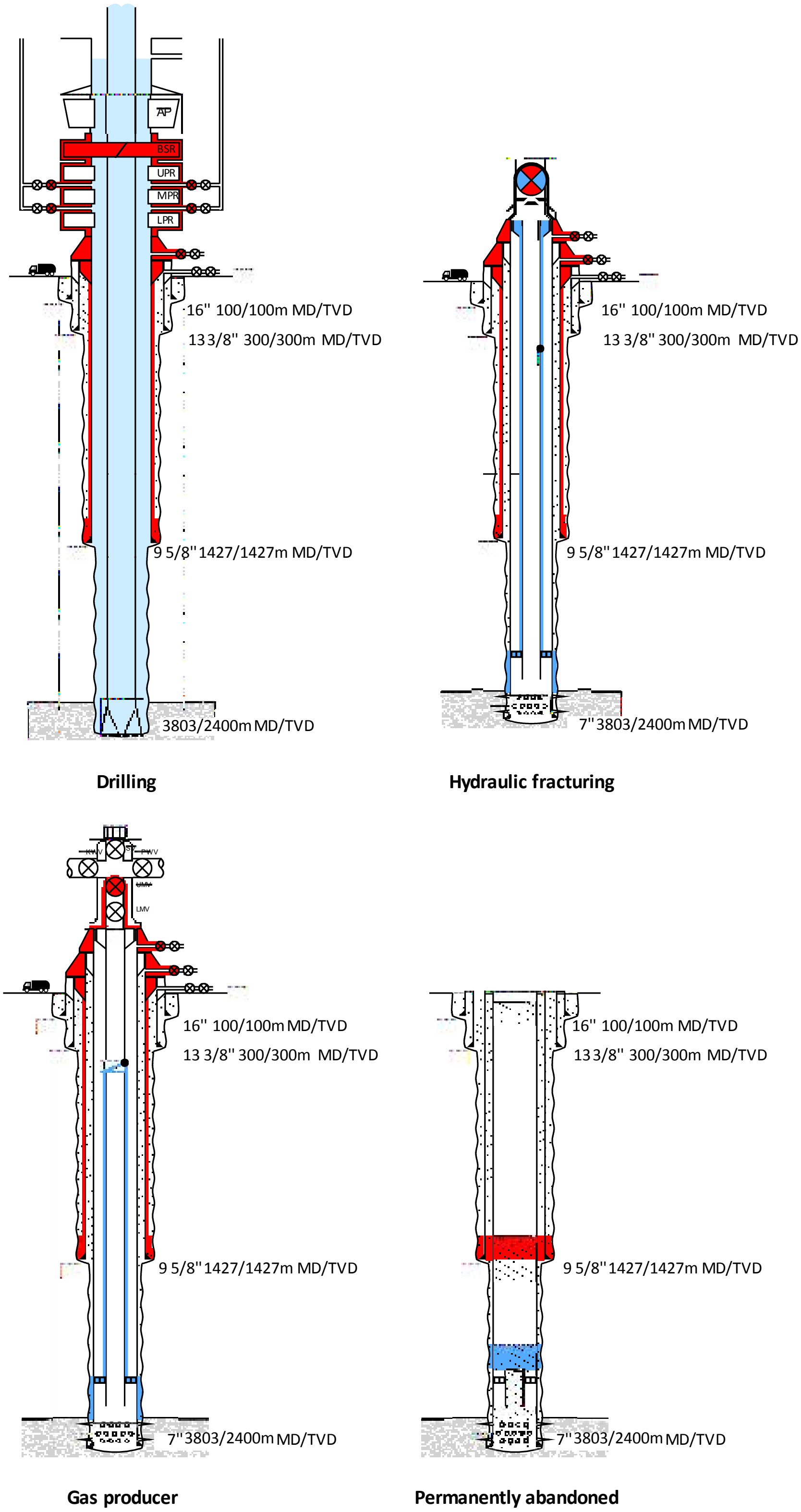
Figure 7: The two-barrier concept, showing the two barriers to various pathways for fluid flow out of the well.



Many different elements make up a well barrier, all of which need to be verified to confirm well integrity. **Figure 8** shows examples of the two-barrier system throughout the well life cycle. The principle is maintained; however, the barriers and barrier elements vary to suit the risks and operational requirements of each phase. Well barrier design will vary between wells, influenced by the design of the well, the characteristics of the resource being drilled and the risks identified.

A **well integrity failure** occurs if all barriers have failed and there is a pathway for fluid to flow into or out of the well. In a two-barrier design, both barriers need to fail for a well integrity failure to occur. A barrier failure will not result in a loss of fluids to or from the environment provided that the second barrier is intact.

Figure 8: Examples of the two-barrier system during different phases of the well lifecycle. The primary barrier is shown in blue and the secondary barrier in red.[47]



[47] Supplied by Wellbarrier AS, Norway, https://www.wellbarrier.com/.

Well integrity issues can be caused by any of the following:

- a **well breach**, including failure of **cement sheaths**, plugs, bonds, casing, and downhole and surface sealing components;
- a hydrological breach, fluid movement between geological formations – including formations not targeted for exploitation; and
- an environmental breach. contamination of or water balance impact on water resources – fluid leaks at surface and causes contamination of water sources.

Various potential impacts on environments can result from poor oil and gas well integrity, such as:[48]

- **impact on groundwater**: contamination of shallow and deep aquifers could be a risk associated with oil and gas well drilling and production activities due to poor well construction;
- **localised hydraulic connectivity between isolated aquifers along a well trajectory**: this can occur because of failed casing, poor cementing or generally poor well construction, decommissioning or abandonment practices; and
- **fugitive gas emissions**: localised gas leakage to both the atmosphere and into aquifers from oil and gas wells can occur because of equipment failure or poor well construction and abandonment practices.

5.1 Well barrier integrity failure mechanisms

This section discusses mechanisms for oil and gas well barrier failure in major phases of a production well life cycle. It also briefly discusses the likelihood of these failure mechanisms occurring, and the consequences and the mitigation measures required if they should do so.

5.1.1 Failure mechanisms associated with oil and gas well drilling

Drilling, the first step in constructing a well, presents a number of potential risks to well integrity. During drilling, the primary well barrier is the drilling fluid pressure exerted on the rock formation surrounding the well. The secondary well barrier includes the drilling blowout preventer, casing and cement, well head and cap rock formation.[49]

Drilling fluid density or mud weight is vital in maintaining well integrity before the casing is cemented. A safe mud weight range (or window) is determined by a lower bound (defined by the **formation pore pressure**) and an upper bound (defined by the formation **fracture gradient**). If the mud pressure is less than the formation pore pressure, formation fluid may enter the well. Uncontrolled influx of large volumes of hydrocarbons may lead to a blowout at the surface, which may in turn have a significant impact on the environment. In shale gas resources, blowouts are unlikely because high overpressures are uncommon in such resources, and the low permeability will limit the volume of any inrush into the well.[50]

Low mud weight can also result in wellbore instability (breakout or washout; that is, enlargement of borehole size). This is not a direct risk to well integrity in terms of containing and controlling the flow of wellbore fluids. However, the significantly enlarged wellbore may result in poor displacement of mud

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[48] Bore integrity review, CoA.
[49] NORSOK D-010.
[50] Royal Society & Royal Academy of Engineering 2012. p25

during cementing and therefore a poor-quality cement sheath behind the steel casing, which may lead to loss of well integrity.[51]

If the mud weight is greater than the formation fracture gradient, drilling fluid may enter the surrounding formations or reservoirs. Most drilling fluids currently used in Australia are water based, generally comprising a mixture of water, clays, fluid loss control additives, density control additives and viscosifiers.[52] If large volumes of drilling fluid are lost into overburden or the reservoir (in particular, into shallow aquifers), this can significantly affect the environment.

To reduce risks of blowout or massive loss of drilling fluid during drilling, formation pore fluid pressure along the well trajectory is estimated. The estimate is based on data from nearby oil and gas wells or a **seismic survey** before drilling. Leak-off tests are conducted to ensure the integrity of casing and cement, and to determine the formation fracture gradient. A functional BOP will significantly reduce or eliminate the risk of environment contamination due to blowout. Because of the low permeability of shale gas reservoirs, significant hydrocarbon blowout from shale gas reservoir is unlikely during drilling.

5.1.2 Failure mechanisms related to casing and cementing

Well integrity can be lost though casing and cementing issues such as channels or voids in the cement; gaps between the formation and the cement, or the cement and the casing; and pore adhesion. These issues can be caused by poor placement of the cement, leakage through casing connections, degradation of the cement sheath and corrosion of the casing.

If channels of drilling mud remain in the annulus, they may provide a **preferential flow** pathway for fluid to migrate inside the cement sheath.[53] If a build-up of compacted drilling mud (also referred to as filter cake) is left on the well surface before cementing, it could dehydrate after the cement sets, resulting in an annulus at the interface of the formation and the cement. Furthermore, cement can shrink during setting, resulting in a **microannualus** (a fracture between the cement and the casing or formation) along the interface between the cement and the casing, or between the cement and the formation rock. **Figure 9** shows photographs of a drilling mud channel in the cemented annulus due to incomplete displacement of the drilling mud and the inner casing being off centre, and of a cement sheath core containing shale fragments recovered from an old well due to poor hole cleaning.

A good cement sheath is a solid that has a low permeability (measured in microdarcies) and **hydraulic conductivity** (that is, in the order of 10^{-6} m/d),[54] and that bonds to the casing and formation surfaces. Such a sheath prevents fluid from migrating within or through the sheath. However, downhole pressure and temperature can change because of operations in the well's history, such as casing pressure tests, well production and shut-in, and reservoir hydraulic fracturing stimulation. These operations lead to changes in well pressure and temperature, which in turn can induce radial deformation of the casing and failure in the cement sheath. This can lead to debonding on the interfaces between the cement sheath and the casing or formation, creating migration pathways through radial fractures (**Figure 10**) and microannuli.[55]

[51] Cook and Edwards 2009.
[52] Cook et al. 2013.
[53] Bonett and Pafitis 1996.
[54] Parcevaux et al. 1990.
[55] Goodwin and Crook 1992; Watson et al. 2002.

Figure 9: A) Incomplete displacement of drilling mud, the resulting drilling-mud channels, and the off-centre inner casing;[56] Used with permission from the Society of Petroleum Engineers. B) Photo of a sidewall cement core containing shale fragments in the cement sheath, indicating poor hole cleaning before cementing the casing.[57] Used with permission from Elsevier.

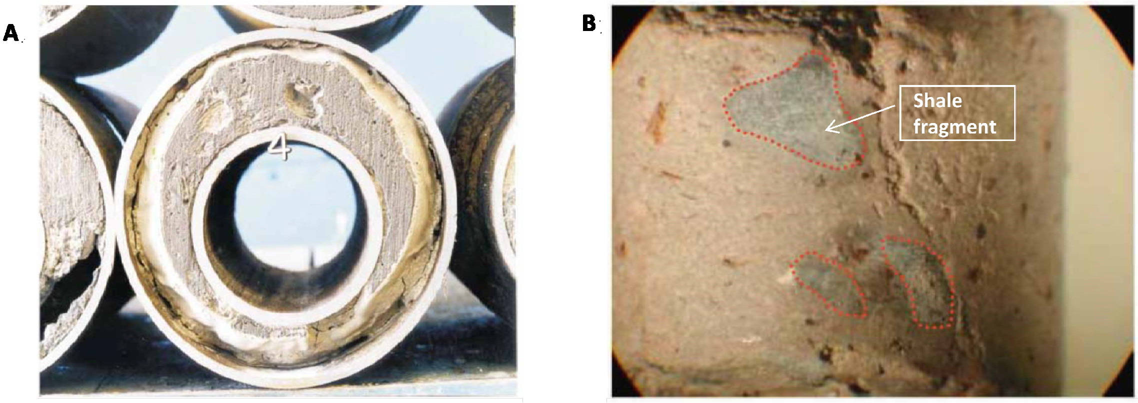

Figure 10: Cement sheath failure, resulting in cracks developing from pressure cycling on the internal casing.[58] Used with permission from the Society of Petroleum Engineers.

The impact of the cement sheath and bond failure on well integrity will depend on the extent of such failure along the wellbore and on specific geological conditions. For example, one study in the Gulf of Mexico found that there was no breach in isolation between formations with pressure differentials as high as 97 MPa (14,000 psi), provided there was at least 15 m (50 feet) of high-quality cement seal between the formations.[59]

Failure mechanisms related to corrosion of casing and chemical breakdown of the cement are discussed in Section 5.1.4.

The risks of the well integrity being compromised due to well casing and cementing can be mitigated by:

- setting the surface casing well below the base of the aquifer system;
- designing a cement slurry that is appropriate for the geological and geochemistry conditions;

[56] Watson et al. 2002.
[57] Duguid et al. 2013. p5666
[58] Watson et al. 2002.
[59] King and King 2013.

- completing the coverage of the hydrocarbon bearing formations with cement in the well annulus;
- selecting materials for casing and other well barrier components that are compatible with the geochemistry environment;
- applying good industry cementing practice; and
- using wireline logging tools to check the quality of cement sheath and bonds on the interfaces and mediatory cementing.

5.1.3 Potential impact of hydraulic fracturing on well integrity

Fluid may migrate via pathways within or external to a production well, stimulated by hydraulic fracturing. These pathways may be created or enlarged by the high cyclic pressures exerted on the well during hydraulic fracturing operations. This section briefly discusses the aspects of hydraulic fracturing that could affect well integrity. These aspects are:

- casing failure induced by hydraulic fracturing; and
- cement sheath and cement bond failure induced by hydraulic fracturing.

Casing failure induced by hydraulic fracturing

High pressures associated with hydraulic fracturing operations can damage the casing and lead to a breach of the seal between formations or aquifers. The production casing through which fracturing fluids are pumped is subject to higher pressures during fracturing operations than during other phases in the life of a production well. Therefore, to maintain integrity, the well and its components must be strong enough to withstand the stresses created by the high pressure of hydraulic fracturing fluid, otherwise a casing failure may result. If casing failures are undetected or are not repaired, they could serve as pathways for fracturing fluids to leak out of the casing. Casing failures during hydraulic fracturing operation or shortly following the operation have been reported in Australia and the United States.[60] In the Northern Territory, the Baldwin 2HST-1 well experienced a shallow casing failure during hydraulic fracturing in 2012.[61] The hydraulic fracturing fluids were retained in the well as a result of the multiple casing design, and the well was subsequently abandoned. The US Environmental Protection Agency (EPA) reported mechanical barrier failures of 3%, but did not indicate whether the hydraulic fracturing fluid was contained by secondary barriers or escaped the well.[62]

Cement sheath and cement bond failure induced by hydraulic fracturing

Cycling of pressure associated with staged hydraulic fracturing operations can damage the cement sheath behind the casing, which in turn can lead to debonding on the interfaces or tensile failure of the cement sheath. **Figure 11** illustrates potential damages to the cement sheath from the high cyclic well pressures.[63] Although a small area of debonding may not lead to fluid migration, it has been found that a microannulus is usually present after perforating or immediately after hydraulic fracturing pumping begins.[64] Maintaining a good bond during hydraulic fracturing can be problematic because the hydraulic fracture fluid pressure can also cause the microannulus to propagate. If this propagation is extensive along the wellbore, it could be a conduit for fluid or gas migration. Migration of gas (in

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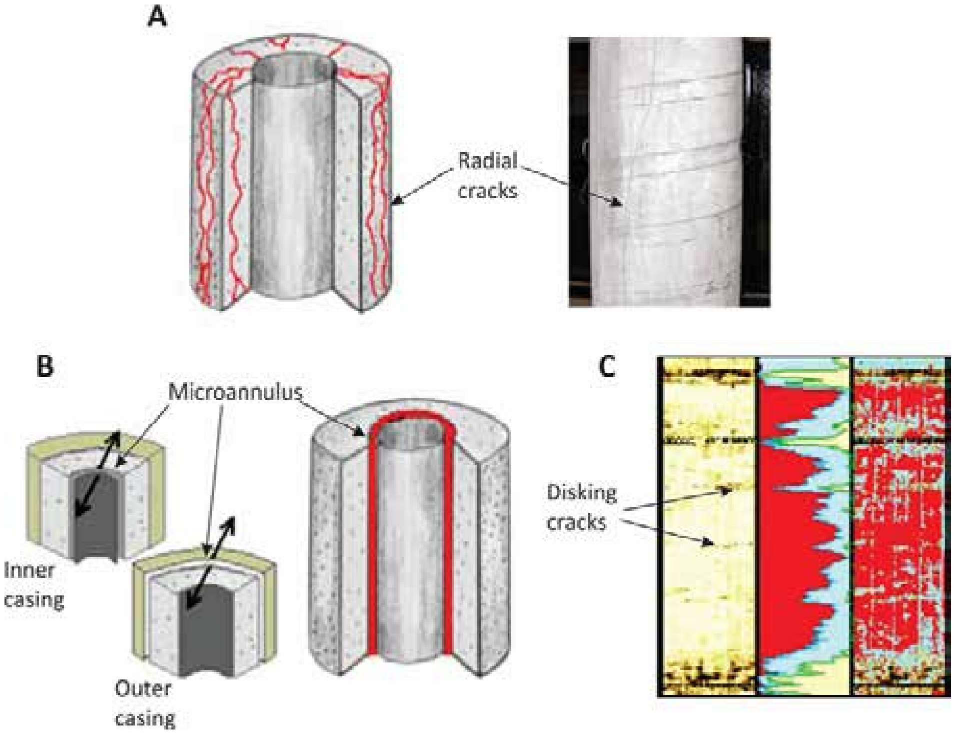
[60] Johnson et al. 2002; US EPA 2015.
[61] DPIR submission 226. p48.
[62] US EPA Report. p6-70
[63] Lecampion et al. 2011.
[64] Behrmann and Nolte 1998.

particular methane) is more likely than the migration of fluid, because the bouyancy of the gas provides a larger driving force for migration through the microannuli.[65] As an example of this mechanism, carbon dioxide (**CO_2**) migration to the surface along a microannulus in a CO_2 **injection well** was recognised as a plausible cause for observed leakage from a CO_2 injector.[66] Fluid migration along a microannulus may also be responsible for some of the sustained casing pressure often observed in production wells. [67]

Figure 11: Types of damage that could be encountered in the cement sheath: A) radial cracks, B) microannulus on the interface with the casing and formation rock, and C) disking cracks in a well log.[68] Used with permission from Elsevier.



The data available suggest that methane migration along the microannulus is the most common integrity issue. The source of a methane leak detected at the surface could be the shale reservoir or other methane-bearing strata in the overburden, including shallow biogenic methane sources. However, the rate of methane leakage along any potential microannulus is likely to be low because of the limited aperture and long length of this pathway and the limited driving mechanism.[69]

5.1.4 Potential fluid migration pathways in decommissioned and abandoned wells

As outlined in Section 3.6, the goal of abandoning a well is to ensure well integrity in perpetuity, re-establishing the natural barriers to the vertical movement of fluid (gas, oil or water) that existed before

[65] Dusseault et al. 2000.
[66] Loizzo et al. 2011.
[67] Loizzo et al. 2011.
[68] Lecampion et al. 2011.
[69] Rocha-Valadez et al. 2014.

the well was drilled. Cement plugs are placed in the well (**Figure 5** and **Figure 12**), creating a barrier to flow within the well, and the combination of casing and cement creates a barrier.

For a leak to occur in an abandoned well, whether the leak is to the surface or cross flow subsurface between different geological formations, three elements are needed:[70]

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

Figure 12 shows a schematic of potential leakage pathways along an abandoned well. Well leakage or failure has been attributed to poorly cemented casing or hole annuli, casing failure and abandonment failure for abandoned wells.[71] Also, preferential pathways for fluid flow that have been identified are interfaces between cement and formation rock or casing, and casing and cement plug for abandoned wells.[72] In the cement sheath, migration of fluid could also occur through fractures, channels and the pore space. In the latter case, fluid flow would occur only when the cement sheath was degraded or did not form properly during the cementing process.[73]

For shale gas wells abandoned using current practices, if any of these leakage pathways were to develop, they are unlikely to allow large fluid flow rates. The small cross-sectional areas and long vertical lengths of the pathways will limit flow. Also, shale gas resources are unlikely to have large driving forces for flow once production is completed because they will generally be depressurised. The characteristically low permeability of shale gas resources will also limit the amount of gas available to flow along a well.

The National Petroleum Council (**NPC**) in the United States is an oil and natural gas advisory committee to the Secretary of Energy that comprises industry and non-industry members. A working group of the NPC made certain observations about abandonment practices:[74]

- the underlying technologies used have not seen significant progress since the 1970s, and there is room for innovation;
- abandonment is a cost for oil and gas companies, and any benefits may not be valued by the companies;
- companies are likely to minimise costs while meeting the minimum standards imposed by regulators – this contrasts with well integrity management during the rest of the well life cycle, where maintaining safety, production and operating efficiency are clear benefits to industry.[75]

The composition of fluids in the reservoir and formations that the well passes through will influence the durability of the casing and cement. Saline groundwater may corrode the casing, and the presence of CO_2 or hydrogen sulphide (**H_2S**) may also affect the casing and cement. The composition of shale gas is similar to that of natural gas in conventional reservoirs. Shale gas is typically a dry gas that contains 60-95% by volume methane and nitrogen, with ethane, propane, noble gases, oxygen and CO_2. The gases CO_2 and H_2S are referred to as sour gases because they can create an acid environment. CO_2

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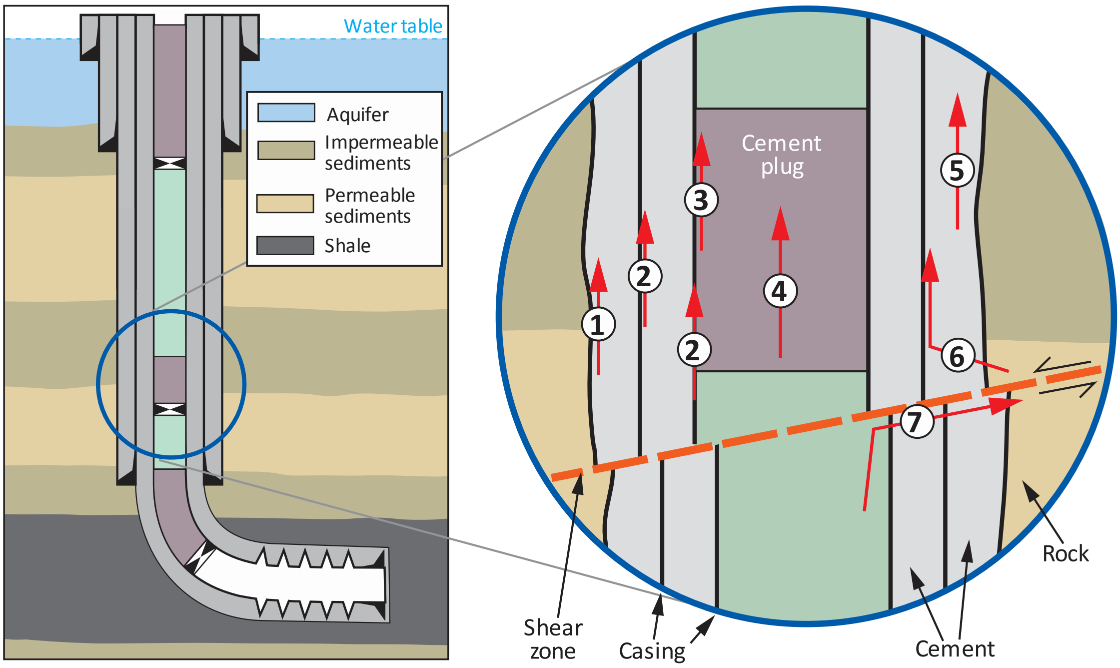
[70] Watson 2004.
[71] Watson and Bachu 2009.
[72] Gasda et al. 2004.
[73] Zhang and Bachu 2011.
[74] NPC North America 2011.
[75] Smith et al. 2016.

concentrations are typically in the range 0-10% by volume.[76] H_2S can occur naturally in some resources, typically at trace concentrations. H_2S generation as a result of hydraulic fracturing activities has also been reported.[77]

Figure 12: Routes for fluid leakage in a cemented wellbore: 1) between cement and surrounding rock formations, 2) between casing and surrounding cement, 3) between cement plug and casing or production tubing, 4) through cement plug, 5) through the cement between casing and rock formation, 6) across the cement outside the casing and then between this cement and the casing, 7) along a shear through a wellbore. After Davies et al.[78]



Durability of casing

Corrosion attacks every metal component, including casing, at all stages in the life of an oil or gas well.[79] Casing damage and loss of well integrity due to corrosion have been widely reported.[80] The cement quality, and cement sheath and bonding integrity are critical in protecting the casing from external corrosion. Factors that will expose the casing to corrosive fluids (if present) and therefore start the process of corrosion are degradation and failure in the cement sheath, and de-bonding of the interfaces along the casing and rock formation.

The impact of CO_2 corrosion on low-alloy steels has been studied extensively at pressures relevant for oil and gas transport (up to 1 MPa CO_2 pressure). A comprehensive review by Choi et al on corrosion of well-casing materials under high pressure for wet and supercritical CO_2 is relevant to geological storage of CO_2.[81] The review found that the corrosion rate of carbon steel under high CO_2 pressure without protective iron carbonate ($FeCO_3$) – that is, in the early stage of exposure – can be as high as about

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[76] Speight 2013.
[77] Pirzadeh et al. 2014.
[78] Davies et al. 2014.
[79] Brondel et al. 1994.
[80] Bazzari 1989; Vignes and Aadnoy 2010; Watson and Bachu 2009.
[81] Choi et al. 2013.

20 mm/year. The corrosion rate can decrease to low values (~0.2 mm/year) in long-term exposure because of the formation of a protective film or scale of $FeCO_3$ on the steel surface.

Corrosion rates depend on the type of steel used. Rates are higher for mild carbon steel (~0.1-1 micrometre/year in favourable conditions such as high pH, and up to 1 mm/year in the case of chloride-induced localised corrosion) than for stainless steel or steel coated with corrosion-resistant material (fractions of a micrometre/year).[82]

A relatively long-term experimental study (up to 1,000 hours) looked at corrosion of casing materials (J55 and N80 steels) exposed to wet and supercritical CO_2 under elevated temperature and pressure.[83] The study confirmed the formation of a protective layer of the corrosion product $FeCO_3$. The corrosion rate decreased dramatically with an increase in test duration, from several mm/year at the initial 100 hours to 0.1 mm/year after 1,000 hours because of the protective effect of the $FeCO_3$ scale formation. The study also evaluated the effect of H_2S (20 ppm) and CO (2,000 ppm) on the corrosion rate of the casing steel. In the presence of these impurities, the weight loss of the casing material was lower than with pure CO_2. The authors concluded that, given the protective effect of $FeCO_3$, there would be little corrosion of the steel casing over a long period of time under stagnant conditions. This means that casing in the reservoir under CO_2 geological storage conditions is likely to remain in place with little structural degradation.

Durability of cement

The cement used in well construction and abandonment is designed to have a long life span. Although no publications were found on the long-term durability of the cement under shale gas well conditions in Australia, studies have investigated cement degradation under simulated CO_2 geological storage conditions.[84] Laboratory experimental studies have focused on the characterisation of cement and of behaviour at the interface of cement and rock, or cement and casing, when exposed to high levels of CO_2. Although CO_2 is a common component of shale gas resources, the conditions in CO_2 storage scenarios are likely to be more challenging for well integrity than would be expected in the Northern Territory's shale gas resources.

Extensive experimental and numerical modelling studies have been conducted to investigate the rate of the interaction between well cement and CO_2 under geologic storage conditions. When pre-cured cement cores are exposed to stationary CO_2 saturated water and supercritical CO_2, the cement alters. This alteration is characterised by a series of concentric fronts of carbonation and dissolution, penetrating from the interface between the fluid and the cement into the unaltered cement core.[85]

Cement integrity is closely associated with the degree of cement carbonation. In general, moderate carbonation of well cement under CO_2 geological storage conditions reduces porosity and permeability, and increases mechanical strength of the cement. However, excessive carbonation has been reported to cause crack formation and loss of compressive strength (although what constitutes the "excessive carbonation" remains a topic for research).[86] For ordinary Portland cement without additives, most experimental studies suggest a carbonate layer thickness of 1-133 mm after 30 years of exposure to CO_2 saturated **brine** or supercritical CO_2. The rate of carbonation is expected to decrease with the increase of exposure time, because the carbonate layer formed in the early stage of exposure has lower porosity than that of the neat cement, hindering penetration of CO_2 and advancement of the

[82] Elsener 2005; Kreis 1991.
[83] Azuma et al. 2013.
[84] Azuma et al. 2013; Satoh et al. 2013.
[85] Zhang et al 2015.
[86] Zhang et al 2015.

carbonate layer towards the interior of the cement.[87] The rate of cement carbonation is affected by temperature, pressure, salinity and mineral compositions of the host rock.

The long-term degradation behaviour of cement in abandoned wells under CO_2 geological storage conditions was evaluated by numerically simulating the **geochemical** reactions between the cement seals and CO_2.[88] The model was validated based on the laboratory experimental results by Satoh et al. before being applied to abandoned wells.[89] It was assumed that supercritical CO_2 or CO_2 saturated water was in contact with the cement. The geochemical simulation of the reactions yielded the extent (length) of the alteration of the cement seals after long periods. For example, the alteration length of cement seals after 1,000 year exposure was about 1 m, leading to the conclusion that cement would be able to isolate CO_2 in the reservoir over the long term.

Several studies have investigated the effect of well cement exposed to a mixture of the acid gases CO_2 and H_2S.[90] The studies have shown that, given a moderate concentration of H_2S in the acid gas (that is, less than 66 mol% H_2S), porosity and permeability changes of the cement are mainly determined by how much of the carbonate species is formed. Formation of sulphur-bearing minerals as a result of interaction between cement and H_2S does not result in significant porosity and permeability changes to the cement, or loss of mechanical strength.

The literature on corrosion and cement degradation considers CO_2 stored at high pressure to be more aggressive than methane.[91] Therefore, it can be concluded that the risk of long-term leakage from shale gas wells (from both casing and cement) would be minimal, provided that shale gas wells are properly designed, installed and maintained. However, there is scope for additional research to specifically assess the impact of abandoned shale gas wells over an extended timeframe.[92]

Durability of cement bonds

As discussed in Section 5.1.2, cement debonding is one of the mechanisms that could compromise well integrity. Permeability evolution along the interfaces (between cement and casing, and cement and host rock) due to flow of CO_2 saturated brine was evaluated in several injection experiments. Microannuli were created artificially between the cement and the casing or host rock, or within the cement core. However, the results from such experiments are not consistent. For example, Carey et al. and Newell and Carey observed an overall decrease in permeability of a cement-steel casing system and a cement-caprock system.[93] This decrease in permeability (or self-healing of defects) was mainly attributed to the migration of re-precipitation of alteration products; that is, $FeCO_3$ for a cement-steel casing system and $CaCO_3$ for a cement-caprock system within the microannulus (interfaces). In contrast, Cao et al. observed that the defects in cement were significantly enlarged, and the overall permeability of the cement-caprock system increased by a factor of eight after 10 days of CO_2 saturated brine flooding.[94] Different flow rates and interface apertures applied during the studies may have contributed to the different results; for example, Cao et al. used a higher flow rate than was used in some of the other studies.

[87] Zhang et al 2015.
[88] Yamaguchi et al. 2013.
[89] Satoh et al. 2013.
[90] Jacquemet et al. 2012; Kutchko et al. 2011; Zhang et al 2015.
[91] Popoola et al. 2013.
[92] NSW Chief Scientist and Engineer, 2014.
[93] Carey et al. 2010; Newell and Carey 2013.
[94] Cao et al. 2013.

Several hypothetical scenarios were simulated in a study by Connell et al.[95] In one scenario, it was found that, for a flow channel 0.01 cm wide, the erosion front took 8 years to travel 50 m for a high deficit in calcium solubility (~400 mg/l) and a pressure gradient (above the hydrostatic gradient) of 0.5 MPa/100 m. The erosion front migration rate dropped significantly with decreased initial channel width; for an initial width of 0.005 cm, the erosion front had migrated 25 m after 12 years. Since the rate of migration drops with distance up the flow channel, the remaining 25 m for the 0.005 cm case would have taken considerably longer than the first 25 m. After the erosion front had broken through the cemented zone of the seal, there was an initial rapid increase in the volumetric flow rate, representing a loss of containment of stored CO_2. These hypothetical scenarios highlight the importance of microannuli in connectivity between different geological formations.

5.2 Well barrier and integrity failure mechanisms summary

Commonly considered well barrier integrity failure mechanisms can be broadly summarised into three categories:

- well integrity failure before installation of casing;
- integrity failure of cement; and
- integrity failure of casing.

Historically, the highest instance of well barrier integrity failures appears to be related to insufficient or poor-quality cementing coverage to seal aquifers or non-reservoir hydrocarbon-bearing formations. In older wells, this was probably due to a lack of information on non-reservoir hydrocarbon-bearing geological layers and the regulatory regime under which the wells were constructed.

The other common well barrier failure mechanism is associated with degradation of the cement sheath and cement bonds to the casing and rock formation. This failure mechanism can be exacerbated if the well is subjected to cyclic pressures, stresses and temperatures. There is a growing body of research on cement durability in the context of CO_2 storage, which is considered to be a more corrosive environment (that is, corrosive formation and reservoir fluids) than methane gas. This research suggests that the degradation length of cement seals after a theoretical 1,000 year exposure would be about 1 m. In a corrosive environment, failure of the metal casing can also occur through corrosion of the metal components of the well.

If a well barrier failure is observed or suspected to have developed, technologies, tools and mitigation measures are available to confirm the failure mechanisms, identify their extent and conduct mitigation operations.

5.2.1 Well integrity failure before casing installation

Before the casing and cement are installed into the borehole, there is the possibility of unintended fluid flow out of or into the borehole. These failures of well control could be caused by:

- drilling fluid pressure that is significantly less than the formation pore fluid pressure;
- overpressured formations or reservoirs;
- drilling fluid pressure that is greater than formation pressure in fractured or permeable formations; or

[95] Connell et al. 2015.

- drilling fluid pressure inducing hydraulic fractures.

Factors that mitigate these failures or the consequences of these failures include:

- identification of geological **hazards** before drilling;
- monitoring of drilling fluid pressure and volume; and
- well control equipment.

5.2.2 Well barrier integrity failure of cement

Failure of the casing cement though degradation, debonding, or insufficient or poor placement of cement could create a conductive pathway and allow movement of fluid or gas up the cement annulus outside the casing. This conductive pathway between formation pore fluids in different geological layers could provide a mechanism for fluid flow if there was a pressure differential or for gas flow driven by buoyancy. Causes of this type of well failure could include:

- unidentified hydrocarbon-bearing formation;
- poor wellbore condition due to excessive borehole breakout or washout;
- poor hole cleaning and mud conditioning, resulting in mud channelling in the cement sheath;
- cement slurry loss into fractured formations;
- uncentralised casing pipe, resulting in a partial cement sheath;
- cement shrinkage;
- cyclic wellbore pressures and temperatures; or
- cement degradation in a corrosive environment.

Factors that mitigate these failures or the consequences of these failures include:

- 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 borehole for cementing;
- cement bond logging to investigate the integrity of the cement sheath; and
- remedial cement repairs applied to identified problem zones.

5.2.3 Well barrier integrity failure of casing

Failure of the wellbore casing though corrosion, burst or collapse could allow loss of wellbore fluid to the surrounding rock. Causes of these failures could include:

- corrosive formation or reservoir fluids;
- poorly cemented casing;
- internal damage or wear to casing; or
- a large pressure difference between the internal and external fluids.

Factors that mitigate these failures or the consequences of these failures include:

- casing pressure monitoring;
- Inspection of casing using multifinger caliper logs, magnetic thickness tool and borehole cameras; and
- casing patching or repair.

5.3 Well failure rates

Compromised well integrity or barrier failure can be an issue in oil and gas production operations. Several studies have identified single-barrier integrity issues in a significant percentage of oil and gas wells; however, the available data indicate that rates of complete well integrity failure (multibarrier failure) affecting groundwater are low. This section reviews barrier and well failure rates reported in open-source international literature for oil and gas wells, with data primarily from North America. The literature presented primarily covers conventional oil and gas resources. Well integrity risks and potential consequences are influenced by the resource characteristics, as outlined in Section 2, and this situation also applies to shale gas wells. There are enough similarities in the well construction methods and the geology (given that shale gas wells are often drilled in the same sedimentary basins as conventional oil and gas wells) for studies of well integrity in other settings to provide an indicator of potential well integrity issues in shale gas development. Data on the integrity of shale gas wells are included in several studies of oil and gas well integrity, and in two studies on unconventional wells. The data presented allow a comparison of shale gas wells with other types of oil and gas wells.

5.3.1 Oil and gas well failure rates in Ohio and Texas, United States

A comprehensive study on groundwater contamination incidents related to conventional oil and gas activities in Ohio and Texas, United States by Kell covered a large well population at different phases of the well life (**Table 1**).[96] It included incidents related to well integrity and those resulting from other activities, including leakage from surface pits, transport and storage of **produced water** and oil, and waste disposal. The data are predominately for conventional oil and gas wells, although the data from Texas include 16,818 wells drilled for shale gas and oil, primarily in the Barnett Shale.

Table 1: Summary of well numbers in the study of wells in Ohio and Texas, United States. [97]

Operation stage	**Number**	
	Ohio (1983-2007)	**Texas (1993-2008)**
Wells drilled	34,000	187,788
Hydraulic fractured wells	27,969	> 13,000
Producing wells	50,342-64,830	237,136-253,090
Wells plugged	28,000	140,818

The average depth of wells drilled in Ohio was 1,140-1,446 m (3,745-4,745 feet) during the study period (1983-2007). In Texas in 2007, the average depth was 2,517 m (8,258 feet). The groundwater contamination incidents and related contamination causes are summarised in **Table 2**; in relation to well-related groundwater contamination incidents, contamination from the orphaned wells had the highest number of reported incidents. For non-well-related incidents, contamination from surface pits or storage tanks had the highest number of reported incidents.

[96] Kell 2011.
[97] Kell 2011.

Table 2: Summary of groundwater contamination incidents at different stages of the well life cycle. Numbers of well integrity incidents related to groundwater contamination are shown in parentheses.[98]

Operation stage	Number	
	Ohio (1983-2007)	Texas (1993-2008)
Site preparation	0	0
Drilling and completion	74 (11)	10 (6)
Hydraulic fracturing	0	0
Production	39 (12)	56 (6)
Orphaned wells	41(41)	30 (28)
Waste management and disposal	26 (16)	75 (6)
Plugging and site reclamation	5 (4)	1 (1)
Unknown	0	39
Total number of incidents	185 (84)	211 (47)

King and King estimated barrier and well failure rates using the data from Kell's study (**Table 3**).[99] The barrier failure rate was 0.1-0.035% and the well failure rate was one order of magnitude lower than that. King and King defined a well barrier as "*a means of containing wellbore pressure and fluids*", and well failure as *"all well barriers failing in sequence and a leakage pathway being created across all the well barriers"*.[100]

The study by Kell relied on reported contamination incidents,[101] and there may have been integrity issues in other wells that did not result in contamination of a drinking water well or were not noticed and reported. Therefore, the barrier failure rate and well failure rate in the study should be considered a low-end estimate of the number of well integrity issues.

Table 3: Estimates of well barrier failure and well failure rates. Modified from King and King, primary data from Kell.[102]

State	Number of wells	Barrier failure frequency range (containment)	Well integrity failure range (containment lost)	Leaks to groundwater by sampling
Ohio	64,830	0.035% in 34,000 wells (0.1% in older wells – worst case)	0.06% for all wells	Details not available
Texas	253,090	0.02% all wells	0.02% for older era wells; 0.004% for newer wells	0.005-0.01% for producers; 0.03-0.07% for injectors
Texas	16,000 horizontal, multifractured	No failure reported	No failure data or pollution reported	No well-associated pollution

In Texas, no groundwater contamination incidents related to hydraulic fracturing were identified over the study period, during which large-volume, multistaged hydraulic fracturing operations for shale gas well stimulation were carried out in over 16,000 Barnett Shale wells. This may be because the wells were characterised while they were still young, so the failure mechanisms described earlier may have

[98] Kell 2011.
[99] King and King 2013.
[100] King and King 2013.
[101] Kell 2011.
[102] Kell 2011; King and King 2013.

not yet had a chance to develop. Intensive, long-term monitoring of stimulated wells would be required to establish whether groundwater contamination occurs over longer timeframes. Only one shale wells was drilled in Ohio during the study period.

5.3.2 Oil and gas well failure rates in Alberta, Canada

In the context of assessing site suitability for CO_2 storage in geological media, Watson and Bachu evaluated the potential for gas and CO_2 leakage along existing oil and gas wells by analysing a large dataset collected by the Alberta Energy Resources Conservation Board (**ERCB).**[103] The database contains information for more than 315,000 conventional oil, gas, and injection wells in the province of Alberta, Canada. No shale gas or oil wells were included in this study because the development of these resources in Alberta is at the exploratory stage. The ERCB records well leakage at the surface as either surface-casing-vent flow (referred to in the industry as **SCVF**) through wellbore annuli or gas migration (referred to in the industry as **GM**) along the outside of the casing. Surface-casing-vent flow occurs when gas enters the exterior production casing annulus from a source formation below the surface **casing shoe**, and flows to surface through the annulus when the casing vent is open, or builds gas pressure in the annulus when the casing vent is closed. Gas migration occurs when gas migrates along the outside of the cemented surface casing (**Figure 13**). The ERCB requires that all wells drilled and cased be tested for surface-casing-vent flow within 60 days of drilling rig release and before final abandonment. Wells must be repaired immediately if they have:

- positive surface-casing-vent flow and exhibit gas flow rates greater than 300 m^3/day;
- a stabilised surface-casing build-up pressure that is greater than the water hydrostatic pressure gradient to the depth of the surface-casing shoe; or
- liquid hydrocarbon flow or saline water flow.

Wells with positive surface-casing-vent flow that fall below these criteria must be checked regularly, with results reported to the ERCB and with repairs carried out at the time of abandonment.

Insufficient cement height in the annulus or poor-quality cement is the cause of surface-casing-vent flow and gas migration. However, producing reservoirs are often not the source for the surface-casing-vent flow and gas migration.[104] As illustrated in **Figure 13,** the gas for the surface-casing-vent flow and gas migration commonly originates from a thin intermediate depth gas zone. The wellbore interval in the reservoir and adjacent formations is often sealed with high-quality cement due to a significant water loss of the cement slurry in the reservoir section during cementing.[105] Conversely, intermediate and shallow depth intervals are often sealed with lower quality cement with a number of filler additives, which do not always generate good primary cement seals. [106]

Figure 14 shows historic drilling activity and occurrence of surface-casing-vent flow and gas migration in Alberta over the past 100 years, both as a percentage of wells drilled in a given year and as a cumulative figure over time. As shown in **Figure 14**, the percentage of cumulative wells with surface-casing-vent flow and gas migration is about 4.6%. The ratio of wells with surface-casing-vent flow and gas migration to the wells drilled decreased from over 4% in 1995 to below 2% in 2005 (**Figure 14**), probably as a result of important regulatory changes, which require that any leaking wells be repaired before well abandonment. An alternative explanation for this reduction is the age of wells. Since about

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[103] Watson and Bachu 2009.
[104] Watson and Bachu 2009.
[105] Dusseault and Jackson 2014.
[106] Watson and Bachu 2009.

1995, there has been a significant increase in the number of wells drilled. These relatively new wells had a maximum age of about 10 years when the study was carried out; consequently, the well failure mechanisms (for example, corrosion) leading to the surface-casing-vent flow and gas migration may have not developed sufficiently to cause an evident problem.

Figure 13: Schematic of gas migration (left side of wellbore) and surface-casing-vent flow (right side of wellbore), originating from a thin, intermediate-source depth zone. Modified from Dusseault et al. 2014.[107]

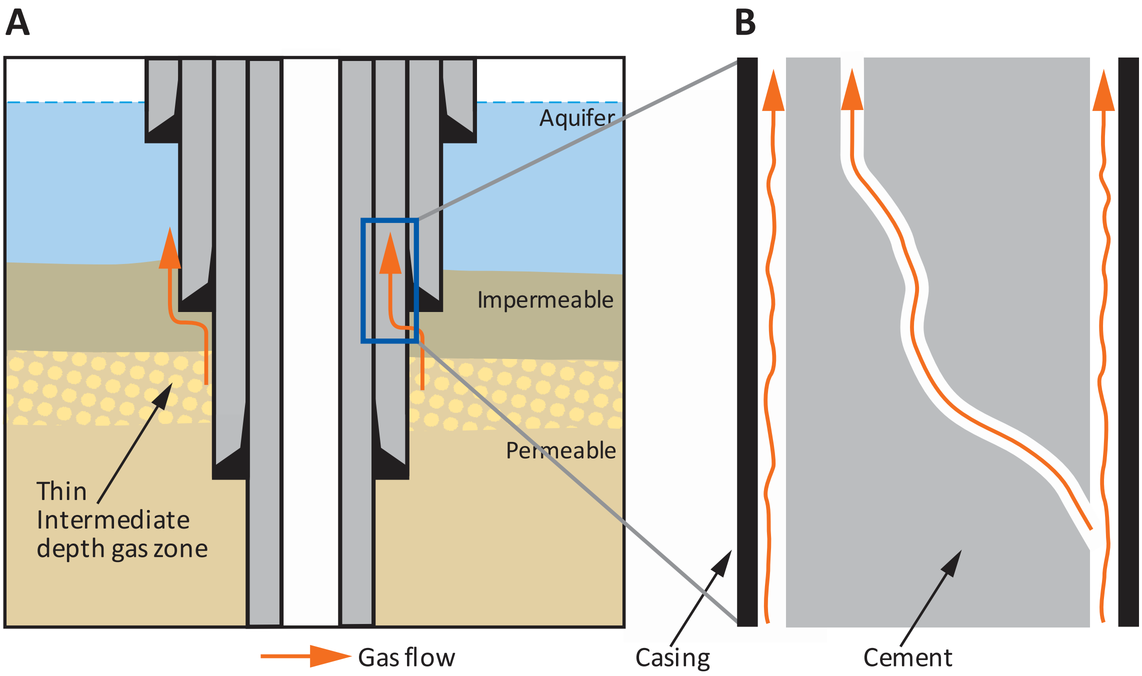
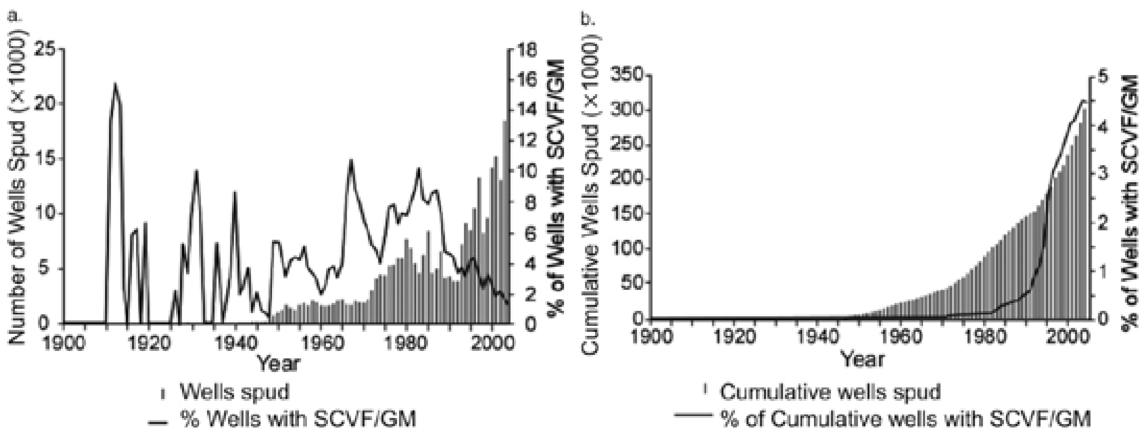


Figure 14: Historical levels of drilling activity and surface-casing-vent flow and gas migration occurrence in Alberta: (a) by year of well drilling commencement and (b) by cumulative wells drilled.[108] Used with permission Society of Petroleum Engineers.

GM, gas migration; SCVF, surface-casing-vent flow



[107] Dusseault et al. 2014.
[108] Watson and Bachu 2009.

Watson and Bachu identified six factors that have a major impact on the occurrence of surface-casing-vent flow and gas migration: geographic area; **well deviation**; well type; abandonment method; oil price, regulatory changes; and un-cemented casing and hole annulus. These factors are discussed below.

Geographic area

The occurrence of surface-casing-vent flow and gas migration is more likely in a test area designated by ERCB for special testing requirements for leakage. **Table 4** compares surface-casing-vent flow and gas migration occurrence in Alberta and within the test area. The percentage of wells with surface-casing-vent flow and gas migration is significantly higher in the test area than the average value in Alberta. The greater percentage of reported leakage may be a reflection of the testing requirements in the test area. However, the more stringent testing requirements could have arisen because of historical well integrity problems in the test area. Saponja discussed typical geological formations that made obtaining and maintaining an adequate cement seal much more difficult in the test area.[109] Furthermore, enhanced oil recovery and other stress-inducing operations that are performed in the area can significantly increase the potential for surface-casing-vent flow and gas migration to occur.[110]

Well deviation

Deviated wells have paths that 'deviate' from the vertical. As shown in **Table 4**, well deviation has a major impact on the occurrence of surface-casing-vent flow and gas migration in the test area. Poor casing centralisation was suspected to be the main reason for the poor cement seals and the resulting increase in well leakage. Casing that is not properly centred in the well may have caused insufficient mud displacement and non-uniform placement of the cement slurry, resulting in mud channels in the cement sheath or partial coverage of the casing.

Table 4: Occurrence of surface-casing-vent flow and gas migration in a test area compared with Alberta province. Data from Watson and Bachu[111]

GM, gas migration; SCVF, surface-casing-vent flow

	Alberta	Test area	% of deviated wells in the test area	Deviated well in the test area
Total number of wells	316,439	20,725	6.5%	4,560
Wells with SCVF	12,458	1,902	15.3%	1,472
Wells with GM	1,843	1,187	64.4%	1,550
Wells with GM/SCVF	176	116	65%	-
SCVF percentage	3.9%	9.2%	-	32.3%
GM percentage	0.6%	5.7%	-	34%
Combined percentage	4.6%	15.5%	-	66%

Well type

The study by Watson and Bachu showed that the drilled and abandoned wells (for example, exploration wells not developed as production wells) reported a surface-casing-vent flow and gas migration occurrence rate of about 0.5%, whereas the overall occurrence rate for all wells was about

[109] Saponja 1999.
[110] Dusseault and Jackson 2014.
[111] Watson and Bachu 2009.

4.6%.[112] The cased and abandoned wells had an overall occurrence rate of about 14%. The cased wells accounted for more than 98% of all well leakage cases reported. The authors attributed their results to historical changes in abandonment requirements for drilled and abandoned wells. The findings may also be due to the fact that the cased and abandoned wells had a long producing life, and the stimulation and production operations created a gas pathway behind the casing, whereas a well that is drilled and immediately abandoned and plugged with a number of long cement plugs does not have such a potential for fluid pathway development.[113]

Abandonment method

The predominant method for well abandonment in Alberta was bridge plugs capped with cement, placed using the dump-bailer method. It was found that this method may not be adequate in providing a sufficient cement seal in the long term.[114] Other abandonment methods – such as placing a cement plug across completed intervals using a balanced-plug method or setting a cement retainer and squeezing cement through **perforations** – are expected to have lower failure rates in the long term.

Oil price, regulatory changes and surface-casing-vent flow and gas migration testing

Watson and Bachu found that the occurrence of surface-casing-vent flow and gas migration correlated strongly with oil price in the period between 1973 and 1999 (**Figure 15**).[115] This correlation may be explained by the level of activity and equipment availability impacting wellbore construction practices in the field. Furthermore, higher prices were accompanied by economic incentives to develop the heavy oil area in Alberta that broadly correspond to the test area. Heavy oil wells require thermal stimulation; high well density; and deviated, directional and horizontal well technology. The correlation between oil price and occurrence of surface-casing-vent flow and gas migration started to diverge in 2000. This may be a reflection on the effect of the regulatory change that began in the mid-1990s.

Un-cemented casing and hole annulus

Watson and Bachu found that insufficient cement height and an **openhole** annulus are the most important indicators for occurrence of surface-casing-vent flow and gas migration.[116] These factors have a significant impact on external casing corrosion, which can create potential leaks through the casing wall. The authors analysed the logs of 142 wells to assess the casing and the cement bond quality, and observed that:

- most of the significant corrosion occurs on the external wall of the casing;
- a significant portion of wellbore length is un-cemented;
- external casing corrosion is most likely to occur in areas where there is no or poor cement; and
- some wells showed that external casing corrosion was located in the area with good cement quality; in most of these cases, channelling within the cement sheath accounted for the external casing corrosion.

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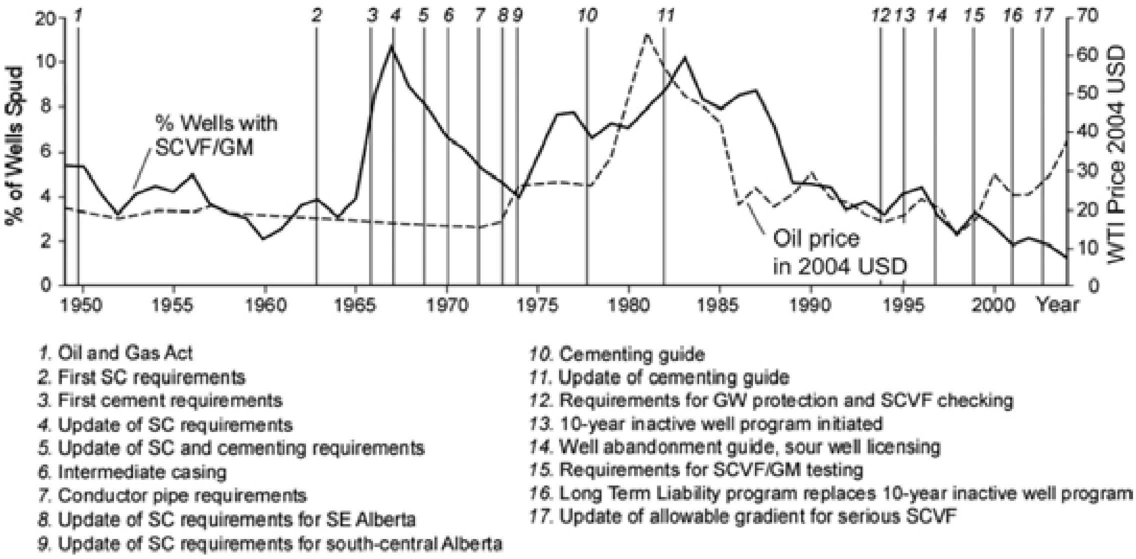
[112] Watson and Bachu 2009.
[113] Dusseault and Jackson 2014.
[114] Watson and Bachu 2009.
[115] Watson and Bachu 2009.
[116] Watson and Bachu 2009.

Figure 15: Occurrence of surface-casing-vent flow and gas migration in Alberta in relation to oil price and regulatory changes.[117] Used with permission Society of Petroleum Engineers.

GM, gas migration; GW, groundwater; SC, surface casing; SCVF, surface-casing-vent flow



5.3.3 Oil and gas well failure rates in Colorado, United States

Wattenberg Field, Denver-Julesburg Basin

Stone et al. conducted a risk assessment of fresh water aquifer contamination due to hydrocarbon or hydraulic fracturing fluid migration from oil and gas wells in Wattenberg field, the largest field in the Denver-Julesburg Basin in Colorado, United States.[118] The Wattenberg Field is predominately a conventional oil and gas field that has been actively developed since the 1970s, with tight gas development involving hydraulic fracturing in later years. Development of shale gas resources has been the focus since 2010, with 973 horizontal wells drilled by 2013. Water aquifer contamination was determined based on detection of **thermogenic** gas or other identified hydrocarbons or fracturing fluids in water wells that are within a radial distance of 0.5 miles from the oil and gas well. The study analysed data from 17,948 wells drilled between 1970 and 2013. It identified possible well barrier failures by remedial cementing operations below the surface casing shoe. The study assumed that remedial cement operations at shallow depths are generally characterised by faulty barriers and the possible presence of sustained casing pressure. Well integrity failures (or catastrophic barrier failures) resulting in migration of hydrocarbons to aquifers were identified by detection of thermogenic gas in **offset** water wells, combined with evidence of catastrophic barrier failure in the adjacent oil and gas wells.

Surface casings of wells drilled in the field in the 1970s were set at a shallow depth, insufficient to fully protect the aquifers. Later, cement remediation was performed below the surface casing shoe to rectify the problem. Since 1994, the surface casing has been set deeper to protect the aquifer. Furthermore, in the 1970s, the top of the production casing cement was designed to cover 'known' hydrocarbon-bearing formations. However, shallow hydrocarbon-bearing formations were not

[117] Watson and Bachu 2009.
[118] Stone et al. 2016b.

discovered until the early 1980s. These overpressured shallow formations have low permeability, and the production cement was not designed to isolate them in the annulus; only since the 1990s have the production cement tops been designed to cover the shallow hydrocarbon-bearing zones.

The wells in the field were categorised based on the well barriers; specifically, the shoe depth of the surface casing, the top of the cement in the production annulus and the number of intermediate casings (**Table 5**). A well in a higher category has a higher number of well barriers and a lower risk of well failure.

Table 5: Wellbore barrier categories, ranked from highest risk to lowest risk. Modified from Stone et al.[119]

Barrier	Category	Surface casing	Intermediate casing strings	Level of top of production casing cement	Risk level
1	1	Shallow		Below overpressured 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 rates of barrier and well failures for the wells in the field were analysed based on well category, and are summarised in **Table 6** for vertical and horizontal wells. No wells of Category 8-12 exist in this field (all the wells have no intermediate casing).

Of the 17,948 wells studied, 10 wells (or 0.05% of original wells) were identified as having well failure (catastrophic barrier failure). Nine wells had a shallow surface casing set above the base of the aquifer, and the other well in Category 5 had deep surface casing and no evidence of water aquifer contamination. However, this latter well had elevated benzene levels at the surface near the well, which could have been due to surface leaks in the flowline or production tank; therefore, it was also included in the count for well failure.

A total of 418 vertical or deviated wells (2.48% of the original wells) were identified as having potential barrier failures that required cement remediation below the surface casing shoe. The shallow surface casing, coupled with the age of the wells, led to sustained casing pressure and subsequent cement remediation. However, no evidence of thermogenic gas migration to the aquifer was found associated with the potential barrier failures from the water testing in adjacent water wells. The most common barrier failure is insufficient surface-casing depth and inadequate production cement design. For wells that had been designed and constructed correctly, no well failures were observed.

[119] Stone et al. 2016a.

Table 6: Potential barrier and well failures in the Wattenberg field. Modified from Stone et al. 2016. [120]

Cat., category; D & A, drilled and abandoned; P & A, plugged and abandoned

	Vertical deviated wells					Horizontal wells				
Well category	**Original well count**	**Potential barrier failures**	**Potential barrier failure rate (%)**	**Well failures**	**Well failure rate (%)**	**Original well count**	**Potential barrier failures**	**Potential barrier failure rate (%)**	**Well failures**	**Well failure rate (%)**
Cat. 1	166	100	60.24	3	1.81	0	0	0	0	0
Cat. 2	621	219	35.27	5	0.81	0	0	0	0	0
Cat. 3	46	16	34.78	1	2.17	0	0	0	0	0
Cat. 4	7	0	0	0	0	0	0	0	0	0
Cat. 5	8,789	77	0.88	1	0.01	0	0	0	0	0
Cat. 6	5,433	6	0.11	0	0	269	0	0	0	0
Cat. 7	1,766	0	0	0	0	704	0	0	0	0
Cat. 8 To Cat. 12	0	0	0	0	0	0	0	0	0	0
Total	**16,828**	**418**	**2.48**	**10**	**0.06**	**973**	**0**	**0**	**0**	**0**
D & A	147					0				
Total wells	16,975					973				
P & A	1105					3				

For horizontal wells that had been constructed since 2010, no barrier and well failures were identified. The study also found no evidence of hydraulic fracturing operations directly contaminating water aquifers in the field. All the well failures were related to hydrocarbon migration through the wellbore to the aquifer or surface.

No corrosion-related barrier and well failures were identified in these wells, because the produced water has lower total dissolved solids and lower salinity compositions than many gas fields in the United States.

Piceance, Raton and San Juan Basins, Colorado, United States

A risk assessment study similar to that for the Wattenberg field in the Denver-Julesburg basin was conducted for the oil and gas wells in three basins in Colorado: Piceance, Raton and San Juan.[121] The assessment confirmed that natural gas migration from poorly constructed wellbores can happen, but occurs infrequently. It also confirmed that there has been no occurrence of hydraulic fracturing fluid contamination in the three basins.

Piceance Basin

Drilling in the Piceance Basin is for conventional oil and gas resources, using vertical and deviated wells. There have been some horizontal exploration wells testing shale resources since 2008. The assessment analysed data from 10,998 wells completed between 1935 and mid-2014, of which 156 wells were drilled and then abandoned without completing for production. All the wells were

[120] Stone et al. 2016b.
[121] Stone et al. 2016a.

categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any cement remediation of any casing string (not just below the surface casing shoe) or evidence of sustained casing pressure. Sustained casing pressure is common in the basin due to shallow gas shows above the top of the production cement in the annulus. In addition, effective cement isolation of the shallow gas-bearing formation is challenging because of **lost circulation** in these shallow formations. Well failures (catastrophic barrier failures) were identified as wells that had barrier failures inducing a conduit for hydrocarbon migration to water aquifers, which was confirmed by isotopic and compositional analysis from offset water wells.

The assessment found that potential barrier failures occurred in 377 of 10,842 wells (3.5% of original producing wells) in the basin (**Table 7**). Category 8 wells had the highest potential barrier failure rate (30%; 18 of the 60 wells). Even though this category had deep surface casing and an intermediate casing string, the top of the production cement was below the top of the gas-bearing formation. Furthermore, casing corrosion contributed to the higher potential barrier failure rates experienced for lower risk well barrier designs in the field. This is because the produced water had high salinity and the gas stream had an average elevated concentration of CO_2. Most of the cement remediation needed was because of holes and pitting developing in the carbon steel casing. The lower risk wells in Categories 6 and 7 had lower potential barrier failure rates (2.33-3.01%). Although the top of the production cement is designed to be above the top of gas-bearing formations for wells in these categories, the potential barrier failure rates being above zero demonstrated the challenging geological conditions that are present in the shallow formation. These conditions prevent effective isolation of production cement and sustained casing pressure from shallow hydrocarbon deposits. Nine of the 10,842 originally producing wells were identified as having well failure (catastrophic barrier failures) related to hydrocarbon migration to fresh water aquifers. All of these nine wells had high sustained casing pressure before thermogenic gas detection in offset water wells. No evidence was found of hydraulic fracturing fluid migration to fresh water aquifers or surface soil.

Raton Basin

Drilling in the Raton Basin has targeted coal bed methane (or **coal seam gas**, **CSG**) resources, with some hydraulic fracturing. There has also been some exploration for conventional and unconventional gas resources. The assessment analysed data from 3,547 wells drilled and completed between 1920 and December 2013 in the Raton Basin, with only 173 wells drilled before 1995. Some 188 of the wells were drilled and subsequently plugged and abandoned without completing for production. All the wells were categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any sign of cement remediation of any casing string. Well failure (catastrophic barrier failure) was identified using the method similar to that for wells in Piceance Basin; that is, detection of thermogenic gas in offset water wells or surface soil, and evidence of well barrier failures contributing to migration of the thermogenic gas to the aquifer.

The assessment showed that the highest potential barrier failure rate occurred in wells of Category 5 or 6 (80.7% for Category 5 and 59.38% for Category 6, **Table 7**). However, cement remediation was mainly needed because of a change in regulations (which required the production cement tops to be above the previous casing shoes), rather than because of well barrier failure or development of sustained casing pressure. Most wells designed in the Raton Basin are in Category 7, which had the lowest potential barrier failure rate because of its redundant barrier designs and the top of production cement being above the surface casing shoe. Some 0.43% of wells in Category 7 received cement remediation due to cement contamination, presence of microannulus or cement cracking.

Table 7: Barrier and well failure in the Piceance, Raton and San Juan Basins.

Cat., category, D & A, drilled and abandoned; P & A, plugged and abandoned

	Piceance Basin					Raton Basin					San Juan Basin				
Well category	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)
Cat. 1	0	0	0	0	0	0	0	0.00	0	0	0	0	0	0	0
Cat. 2	48	4	8.33	0	0	23	2	8.70	1	4.35	12	0	0	1	8.33
Cat. 3	145	10	6.90	2	1.38	4	1	25.00	0	0	13	0	0	0	0
Cat. 4	5.9	10	1.96	0	0	45	1	2.22	0	0	71	0	0	0	0
Cat. 5	1,789	125	6.99	2	0.11	399	322	80.70	0	0	54	30	55.56	1	1.85
Cat. 6	6,233	145	2.33	4	0.06	32	19	59.38	0	0	348	84	24.14	0	0
Cat. 7	1,862	56	3.01	1	0.06	2,800	12	0.43	2	0.07	2,677	4	0.15	0	0
Cat. 8	60	18	30.00	0	0	7	3	42.86	0	0	64	5	7.81	0	0
Cat. 9	90	2	2.22	0	0	0	0	0	0	0	17	0	0	0	0
Cat. 10	0	0	0	0	0	20	2	10.00	0	0	148	4	2.70	0	0
Cat. 11	105	7	6.67	0	0	20	1	3.45	0	0	427	0	0	0	0
Cat. 12	1	0	0	0	0	0	0	0.00	0	0	0	0	0	0	0
Total	**10,842**	**377**	**3.48**	**9**	**0.08**	**3,359**		**10.81**	**3**	**0.09**	**3,831**	**127**	**3.32**	**2**	**0.05**
D & A	156					188					358				
Total wells	10,998					3,547					4189				
P & A	335					352					387				

Of the 3,359 original producing or shut-in wells, three (or 0.09%) were identified to have well failures, with one Category 2 well and two Category 7 wells. In one Category 2 well and one Category 7 well, the failure was due to ineffective plugging and abandonment of the wellbores rather than the initial wellbore design. The reason for the failure in the second Category 7 well was unclear because of uncertainty about the origin of the gas detected in the water well. The study also found no direct evidence that any of the hydraulic fracturing operations contaminated the fresh water aquifers in the basin.

San Juan Basin

Drilling in the San Juan Basin targeted coal bed methane (or coal seam gas) resources, with some hydraulic fracturing. There has been some exploration for conventional and unconventional gas resources, and some conventional oil production. The assessment analysed data from 4,189 wells drilled between 1901 and 2014 in the San Juan Basin, of which 358 wells were drilled and subsequently plugged and abandoned without being completed. All the wells were categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any cement remediation of any casing string, based on the assumption that the remediation was needed because the oil and gas wells experienced sustained casing pressure. Well failure was identified using a method similar to that for wells in Piceance Basin; that is, detection of thermogenic gas in offset water wells or surface soil, and evidence of well barrier failures contributing to the migration of thermogenic gas to the aquifer. The potential barrier and well failures in the basin are summarised in **Table 7.**

Of 3,831 originally producing wells, 127 (3.32%) were found to have potential barrier failure. This relatively low overall potential failure rate resulted from the predominantly robust barrier designs implemented in the basin. Category 5 wells had a high potential barrier failure rate of 55.56%, due to the top of production cement being lower than the top of the gas-bearing formation, whereas the design of the Category 6 wells corrected this defect. However, the relatively high potential barrier failure rate of 24.14% in the Category 6 wells showed that the shallow geological conditions made it difficult to effectively create a cement seal in the production casing annulus. Most of the wells with a Category 7 well design had a relatively low potential barrier failure rate (0.15%). Some 54% of the wells with potential barrier failure were originally completed between 1999 and 2004.

As shown in **Table 7**, two of the 3,831 originally producing oil and gas wells (0.05%) in the basin were identified as having well failures. This relatively low failure rate was due to the implementation of a low-risk nested barrier design with deep surface casing (Category 7). This design was adopted because of the geology of the basin, shallow coal deposits and structurally shallow depth of hydrocarbon-bearing formations. The two wells with catastrophic well failure were drilled before 1961. The Category 2 well was found to have been improperly plugged and abandoned in the 1960s, and the Category 5 well had improper cement coverage in the intermediate casing annulus.

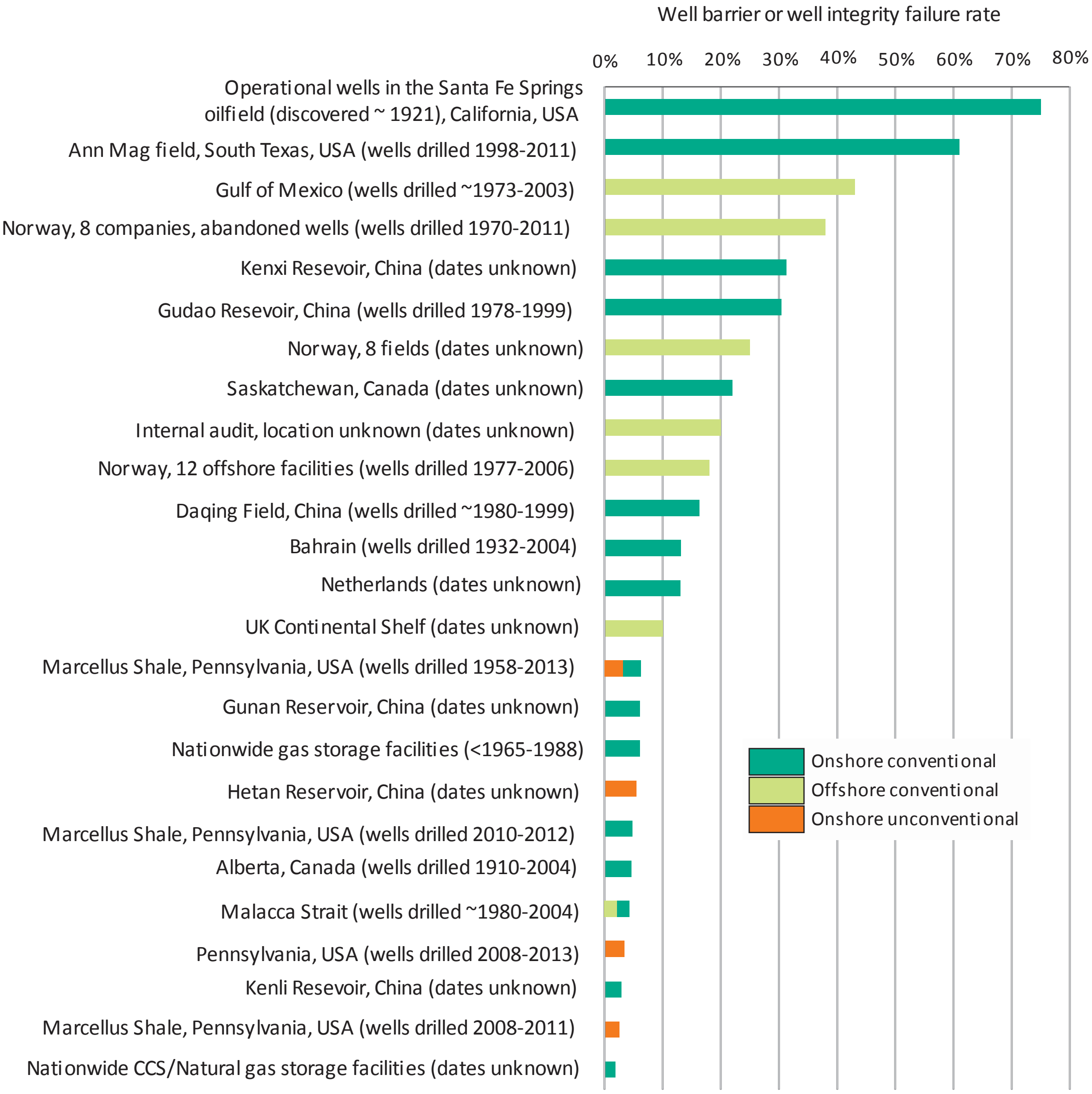
5.3.4 Global oil and gas well failure rates

Davies et al. reviewed studies of well barrier and well integrity failures, based on datasets collected from the public domain, including published literature and online resources.[122] The wells contained in the datasets included production, injection, idle and abandoned wells drilled globally, both onshore and offshore, for exploiting conventional and unconventional reservoirs, and CO_2 and natural gas storage. The datasets vary considerably in terms of the number of wells examined, well age and well design. The study did not attempt to distinguish barrier failures from well integrity failures that led to environment contamination. Also, the study compared data from a range of resource types, jurisdictions and well ages, and its significance and conclusions has been criticised on this basis.[123] As expected, the well barrier and integrity failure rates derived from this study vary widely, ranging from 1.9% to 75% (**Figure 16**). The weighted average rate across all studies is at the lower end of this range, at 6.8%.

The high variation in rates of well integrity issues reported in the literature studied by Davies et al. demonstrates the difficulty in comparing studies on wells that are drilled for different purposes, and that have different criteria for well integrity or well barrier failure. Other confounding factors include geological conditions, regulatory requirements on well construction and abandonment standards, well age, well type and well purpose. Davies et al. also analysed shale well data from Pennsylvania, and this is discussed in Section 5.3.6.

[122] Davies et al. 2014.
[123] Davies et al. 2015; Thorogood and Younger 2015.

Figure 16: Well barrier and integrity failure rates for wells from 25 different studies. Modified from Davies et al.[124]



5.3.5 Well integrity data from Australia

There are only two studies of well integrity data from Australian jurisdictions. One is on coal seam gas well failure rates in Queensland,[125] and the other is on oil and gas failure rates in Western Australia.[126] No other published data are available.

Coal seam gas well failure rates in Queensland, Australia

To date, few estimates have been made of failure rates for coal seam gas wells in Australia. The GasFields Commission Queensland reports statistics from well integrity compliance auditing undertaken from 2010 to March 2015.[127] During this period, 6,734 coal seam gas wells (for exploration,

[124] Davies et al. 2014.
[125] GasFields Commission Queensland 2015.
[126] Patel et al. 2015.
[127] GasFields Commission Queensland 2015.

appraisal or production) were drilled in Queensland, and about 3,500 wells were actively producing by the end of 2014. The non-producing wells do not have gas flow at the well head. The auditing involved testing for both subsurface gas well compliance and surface well head compliance. For the subsurface equipment, no leaks were reported, whereas there have been 21 statutory notifications (a rate of 0.3%) concerning suspect downhole cement quality during construction. After remediation, the cement failure rate was determined to be zero. For subsurface equipment, the conclusion is that the risk of a subsurface breach of well integrity is very low to near zero. A total of 199 surface well head leaks have been reported, all of which have subsequently been fixed.

Oil and gas well failure rate in Western Australia

Patel et al. reported a study on well integrity issues for all the oil and gas wells drilled onshore in Western Australia and in state waters that have not yet been decommissioned.[128] The study found that, of 1,035 non-decommissioned wells, 122 (less than 12%) had compromised well integrity or well barrier failure, but none of these failures resulted in leakage to the external environment.

Production **tubing** (see **Figure 3**) failure was the main cause of well barrier failure. Of the 1,035 wells studied, 86 wells (8.3%) had tubing failure. Tubing leaks can occur through holes being corroded or eroded by production and injected fluid inside the tubing, or from twisting of the tubing.

Casing failure in production casing is mainly due to corrosion, pressure differential and thermal effects, causing the pressure behind the production casing to exceed the collapse resistance of the casing. Of the 1,035 non-decommissioned wells, 22 (2%) had production casing failure.

The other barrier failure identified related to surface production equipment, such as the well head or Christmas tree (the assemblage of valves, spools and fittings used in developing wells, named for its resemblance to a decorated Christmas tree). Surface integrity failure is far less frequent than subsurface failure, because the surface is easier to access and maintain.

The study found that well barrier failure correlated with the age of the well, as shown in **Table 8**.

Table 8: Well integrity data for Western Australia showing a correlation between the age of the well and the type of barrier element failure. Data from Patel et al.[129]

Well age (years)	Tubing failure (%)	Well head or Christmas tree failure (%)	Casing failure (%)
0-10	0.2	0.1	0.4
11-20	0.8	0.0	0.2
21-30	0.9	0.2	0.6
31-40	0.7	0.3	0.3
41-60	5.5	0.8	0.5

5.3.6 Shale gas well integrity

Seven studies have analysed data specific to shale gas wells:

- Five studies – Considine et al., Davies et al. Ingraffea, Ingraffea et al. and Vidic et al. – present data for shale gas wells drilled in the Marcellus Shale in Pennsyvania, United States. The

[128] Patel et al. 2015.
[129] Patel et al. 2015.

Ingraffea et al. study is discussed in Section 5.3.5 and includes conventional oil and gas wells, whereas the other studies only consider unconventional wells;[130]

- Stone et al. present data on shale gas wells drilled in the Wattenberg field, Colorado, United States, as part of a broader study of well integrity in this field discussed in Section 5.3.3;[131] and
- Kell presents data on shale gas wells drilled in Texas, United States, as part of a broader study of oil and gas well integrity in Texas and Ohio, discussed in Section 5.3.1.[132]

All of these studies follow similar methodologies. They rely on reports of violations or incidents in publicly available databases of well data. The five studies conducted in Pennsylvania all relied on publicly available data from the Pennsylvania Department of Environmental Protection Office of Oil and Gas Management website and examination of notices of violations (**NOV**). As outlined in Section 5.3.5, Ingraffea, Ingraffea et al. and Davies et al. also reviewed inspectors' comments for additional evidence of well integrity issues.

The Considine et al. study analysed all well-related NOVs, including those related to surface operations. Their data showed that 2.58% of wells drilled in the study period had an NOV related to well integrity. They characterised these as blowouts (0.11%, 4 events), gas migration (0.06%, 2 events) and cementing and casing issues (2.41%, 85 events). The authors classified blowout and gas migration events as major events based on the level of severity of potential pollution, and these can be considered to be well integrity failures. For all but one of these major events, there is documentary evidence that the impacts had been remediated or that remediation was underway at the time of the study. Vidic et al. found that only 16 out of 6,466 wells (0.25%) were issued with an NOV indicating that the operator failed to prevent a gas or fluid release to an aquifer (interpreted as well integrity failures).

The Texas and Colorado datasets were part of larger studies described in Sections 5.3.1 and 5.3.3, which found no reported incidents of well integrity or hydraulic fracturing related issues for shale gas wells.

Table 9 summarises the findings of these studies. The percentages of wells with potential well integrity issues in the studies from Pennsylvania are similar to those found for oil and gas wells elsewhere. However, most of these studies do not distinguish between single-well barrier failures and total failure of well integrity that can lead to impacts on the environment. None of these studies looked at the scale or consequences of failures in well integrity.

Table 9: Summary of published well integrity data specific to shale gas resource development.

Location and study	Time period	Number of wells	Well barrier issue rate	Well integrity failure rate
Pennsylvania, Ingraffea	2010 - Feb 2012	4,934	7.6%	Not reported
Pennsylvania, Considine et al.	2008 - August 2011	3,533	2.58%	0.17% blowouts and gas migration
Pennsylvania, Vidic et al.	2005-2012	6,466	3.4%	0.25% release to groundwater
Pennsylvania, Ingraffea et al.	2002-2012	6,007	6.2%	Not reported
Pennsylvania, Davies et al.	2005-2013	8,030	6.26%	1.27% leak gas to surface
Colorado, Stone et al.	2010-2014	973	0	0
Texas, Kell	1993-2008	16,818	0	0

[130] Considine et al. 2013; Davies et al. 2014; Ingraffea 2012; Ingraffea et al. 2014; Vidic et al. 2013.
[131] Stone et al. 2016b.
[132] Kell 2011.

5.4 Well failure rates summary

This section reviews the well barrier and well integrity failure rates reported in the open literature. Well barrier failure was identified in several ways, including by sustained casing pressure, surface-casing-vent flow or requirements for remediation of barriers. Well integrity failure was identified by the detection of hydrocarbons in nearby water wells, gas migration outside the surface casing or NOVs issued from regulatory bodies. Many studies do not distinguish between well barrier failures and well integrity failures. This distinction is important because a full integrity failure is required to allow a pathway for contamination of the environment.

The data that have been reviewed indicate that the rate of total well integrity failures that have the potential to cause environment contamination is about one in 1000, and several studies reported no well integrity failures. The rate for single-well barrier issues or failures is about 1-10 in 100, and is consistently in this range for onshore unconventional resources. Well barrier failures do not indicate that a well integrity failure will occur. In most cases, well barrier issues can be remediated. The data specific to shale gas wells indicate that well integrity issues occur at a rate at the lower end of the rates observed for oil and gas wells in general.

An important observation from the available data on well integrity for oil and gas wells is the importance of resource characteristics, well construction methods and regulatory settings. Few studies have investigated the correlation between well construction methods, geological conditions and failure rates. Notable exceptions are the studies by Stone et al. and Watson and Bachu.[133] This is demonstrated in **Figure 17**, which aggregates the data based on well category from the studies by Stone et al. The categories take into account the well construction (that is, the number of barriers) protecting shallow aquifers. There is a strong correlation between well construction category and well barrier failure rates, and between well barrier failure rates and well integrity failure rates. The only exception to this correlation is the barrier failure rates for Category 8 wells in the Raton and Picean Basins (**Figure 17, Table 5** and **Table 7**). Stone et al. described Category 8 wells as those having deep surface casing and intermediate casing strings, and with the top of the production casing cement below the top of the gas zone. The barrier failures were interpreted to be related to inadequate cementing of the production casing. There were no well integrity failures, indicating that the remaining barriers provided protection of shallow aquifers.

Watson and Bachu demonstrated that well barrier failure rates reflect the geological conditions of the wells, regulatory requirements in place during well construction and abandonment, era in which a well was constructed, well type, well purpose and well history, as well as factors such as oil price, availability of equipment and materials, and operator's technical competence in the well construction or abandonment.[134] The authors also found that failure rates of well barriers and well integrity were lower for newer wells.

For shale gas wells, Stone et al. showed no well barrier or well integrity failures when wells were constructed according to modern construction standards; similarly low rates were found for conventional wells drilled in the same basin and constructed to the same standards.[135] Ingraffea et al. showed variations in well integrity issues for shale gas wells at different locations in Pennsylvania,

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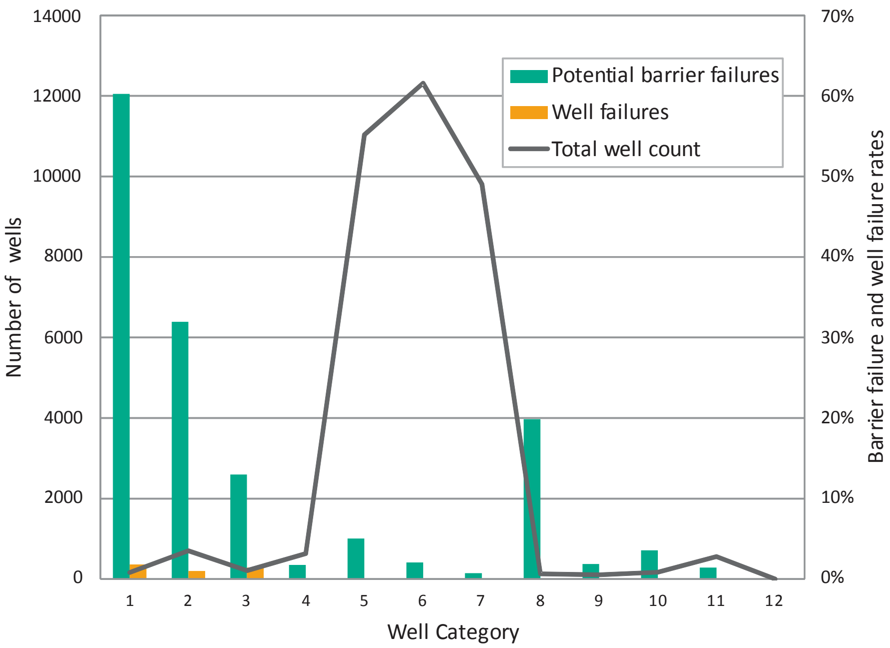
[133] Stone et al. 2016a; Stone et al. 2016b; Watson and Bachu 2009.
[134] Watson and Bachu 2009.
[135] Stone et al. 2016b.

again highlighting the importance of local resource characteristics.[136] Where well integrity issues occur, they can generally be remediated, as demonstrated by Considine et al.[137]

The risk of well integrity issues appears to be reduced by constructing wells with deep surface casing to protect aquifers, and using intermediate casing or production casing with adequate cementing. Local conditions (including geology, aquifer depth, presence of pressured zones, presence of shallow gas-bearing zones and presence of corrosive fluids) should be taken into account when determining casing and cementing depths.

Figure 17: Aggregated data from well integrity studies in several basins in Colorado (well categories are defined in **Table 5**). Stone et al.[138]



[136] Ingraffea et al. 2014.
[137] Considine et al. 2013.
[138] Stone et al. 2016a; Stone et al. 2016b.

6 Potential for hydraulic fractures to act as contaminant transport pathways

Contamination of surface and groundwater assets may occur if deep formation fluids or introduced chemicals from drilling and hydraulic fracturing activities reach water-bearing formations, overlying aquifers or nearby water bores. Conceptually, these migration pathways could be a hydraulic fracture lateral intersection with a water bore; a direct hydraulic fracture connection from the reservoir into the overlying aquifer; a hydraulic fracture intersection with a natural fracture or fault, which then connects to an aquifer; or cracks in the annular region between the casing and the well.[139] These pathways are illustrated in **Figure 18**.

Typically, shale resources are found 1,500-4,000 m below the earth's surface. Given that most groundwater resources are only a few hundred metres deep, it is unlikely that hydraulic fractures will grow into a nearby water bore, which are much shallower.[140] Dusseault and Jackson conclude that the migration of hydraulic fracturing or formation fluids (including natural gas) to the surface as a result of hydraulic fracturing of typical shale gas reservoirs is unlikely, except when abandoned or suspended wells are intersected by the hydraulic fracturing fluids during the high-pressure stage of fluid injection.[141]

Recent studies have looked into the possibility of shallow groundwater contamination due to hydraulic fracturing fluid migration along conductive faults. Birdsell et al. reviewed the recent literature on this topic and used transport simulations to quantify the amount of fracturing that could potentially reach an overlying aquifer.[142] Based on modelling studies, the authors concluded that the likelihood of hydraulic fracturing reaching a water resource is low when the vertical separation between the reservoir and the overlying aquifer is large and other natural pathways (such as faults or leaky wells) are absent. Even in the absence of a permeable pathway, their results show a potential upward migration of hydraulic fracture fluids of about 100 m through a relatively low-permeability overburden. Birdsell et al. also reported instances of fluid migration that have occurred in the past, and the need for detailed modelling approaches that can explain these occurrences. [143] The finding of this study have been cited in a report from the US EPA.[144] In the case of deep shale formations, it is unlikely that hydraulic fractures would grow in a way that stimulated a conductive pathway between a shale reservoir and an overlying aquifer, when the vertical separation distance is in the order of thousands of metres. [145]

Using a numerical groundwater flow model that considers advective transport through bulk media and preferential flow through fractures, Myers concluded that the interaction between fractured shale and fault zones can reduce the time for the contaminants to reach near-surface aquifers from thousands of years to tens or hundreds of years.[146] However, Saiers et al. identified significant shortcomings in that transport model; the authors concluded that the assumptions and the prediction do not faithfully

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139 Reagan et al. 2015.
140 Davies et al. 2012; Flewelling et al. 2013.
141 Dusseault et al. 2014.
142 Birdsell et al. 2015.
143 Birdsell et al. 2015.
144 US EPA Report.
145 US EPA Report.
146 Myers 2012.

represent the reality, and they suggested ways in which the model could be improved.[147] Cohen et al. identified additional issues in the model assumptions and boundary conditions, and also pointed out critical errors in the calculations.[148] Gassiat et al. used a finite element-based numerical groundwater flow model and publicly available data for shale gas basins to simulate hydraulic fracturing in the vicinity of a permeable fault zone. The authors found that, under certain conditions (such as the presence of a highly permeable fault, high overpressure in the shale unit and fracturing in the upper portion of the shale near the fault), contaminants can reach shallow aquifers in less than 1000 years after fracturing.[149] They suggested that fracturing operations be avoided near potentially conductive faults, and that fluid migration via faults be monitored over longer timespans. Flewelling and Sharma argued that these predictions are unreliable because the analysis contains significant gaps, the modelled scenarios are unreasonable, and the model has not been validated against physically plausible conditions; they concluded that there is not enough evidence to conclude that this type of migration could occur over the specified timeframe.[150] Kissinger et al. simulated long-term methane migration through a fault zone for the Lower-Saxony region in Germany, and found that migration of methane to shallow layers can occur in the presence of a fully penetrating fault zone and low gas saturation of the overburden (1 %).[151] However, the authors noted that these results contain significant parameter and scenario uncertainties, and therefore need to be treated with caution. Further studies with better numerical models are required to fully understand subsurface flows, and to investigate fluid migration over long time scales and its impact on aquifers.

Laboratory studies suggest that aquifer contamination via a subsurface pathway is unlikely. Engelder et al. conducted a series of imbibition experiments on cuttings recovered from the Union Springs Member of the Marcellus gas shale in Pennsylvania, and on core plugs of the Haynesville gas shale from northwest Louisiana, and demonstrated that aquifer contamination due to fracture propagation through a subsurface pathway is unlikely.[152] The authors attribute this finding to reasons such as low water saturation of gas shale, sequestration of injected water into dry gas shale by imbibition, the presence of capillary seals that prevented gas leakage, and large osmotic pressures that will drive the treatment fluids into gas shale. A study by Flewelling and Sharma discusses the main barriers to upward fluid migration of fracturing fluids, concluding that the timescales for migration would be long (more than a million years), given that the permeability and flow rates are low.[153] Even in overpressured basins, they suggest that the permeability required to maintain elevated subsurface pressure over geologic time will result in negligible vertical flow rates.

In the context of shale gas development, microannulus delamination of the wellbore (as discussed in Section 5.1.2) is considered to be the most plausible contamination pathway by which introduced chemicals from drilling and hydraulic fracturing, and hydrocarbons in the formation, could leak into an overlying aquifer or the atmosphere. For fluid to move, there would need to be a driving force: buoyancy for oil and gas, and pressure gradients for water. Pressures within the shales will decrease during production, and any recovery in pressure would only occur over geological timescales. The volume of water in resource shales, including any residual fracturing fluid, is small in the context of the overall groundwater system, and it is mostly immobile.

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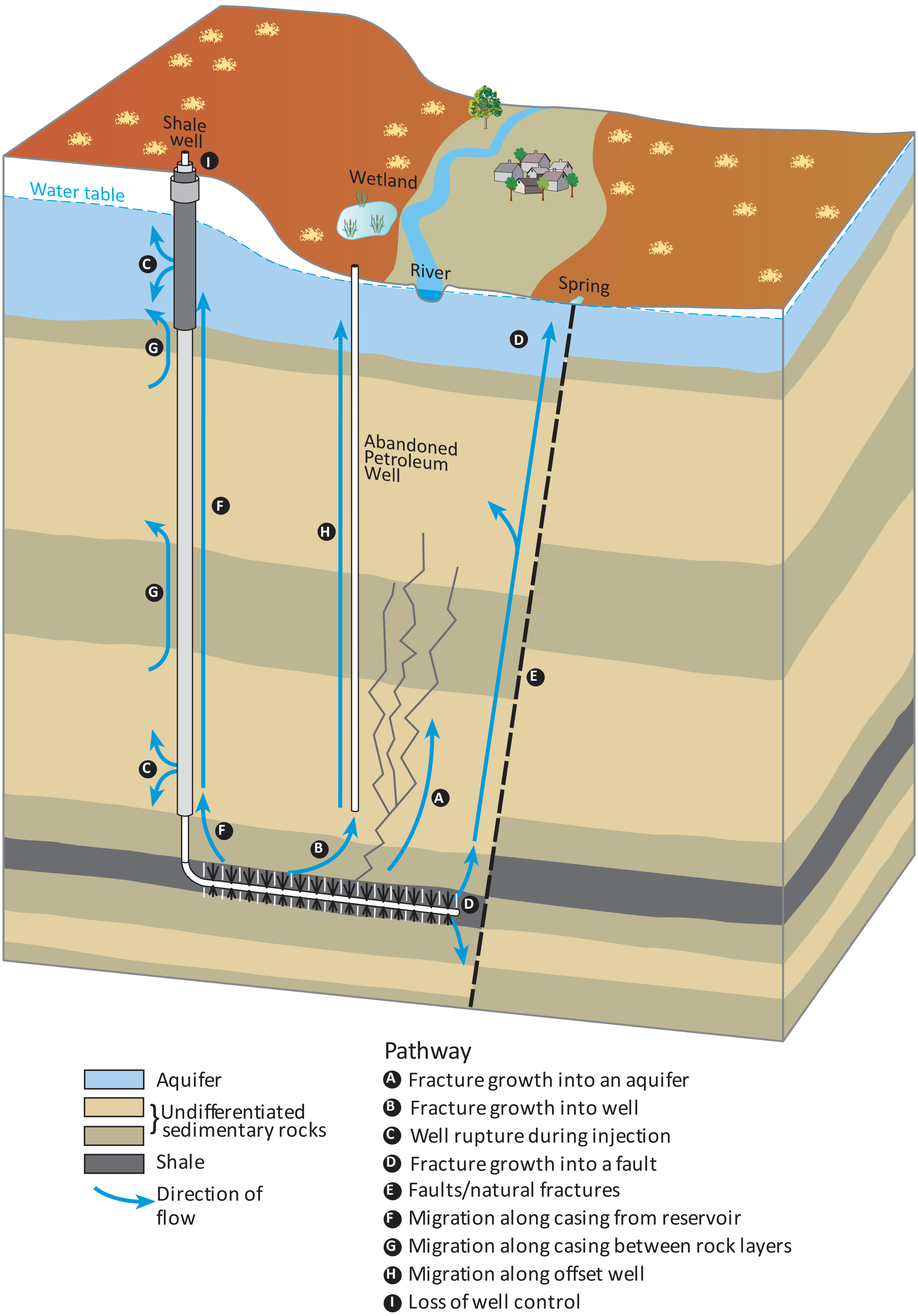
[147] Saiers and Barth 2012.
[148] Cohen et al. 2013.
[149] Gassiat et al. 2013.
[150] Flewelling and Sharma 2014.
[151] Kissinger et al. 2013.
[152] Engelder et al. 2014.
[153] Flewelling and Sharma 2014.

In situations such as the Northern Territory where there is a large vertical separation between aquifers and the shale gas layer, and the layered geology includes large stress barriers, there is a low possibility for hydraulic fracturing fluids to reach an overlying aquifer.

Figure 18: Potential contamination pathways from drilling and hydraulic fracturing activities.



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7 Well integrity management

Well integrity management across the life cycle of a well has become a focus for industry over recent years, in recognition of the value of proactive well integrity management in reducing risks.[154] Well design needs to consider hazards that might arise throughout the life cycle, and the design will have ramifications for how wells can be operated later in their life. The operating life of a well can cover several decades, and responsibility for a well is often passed between different teams within the operator. Third parties are often involved in well drilling and operations, and in the supply of materials such as casing and cement. The level of complexity in the design and operating parameters for wells means that there are risks associated with the transfer of responsibility between different teams and throughout the life of the well. Life cycle well integrity management aims to minimise these risks by establishing processes around well integrity management.

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 (**WIMS**) to ensure that well integrity is maintained throughout the well life cycle by the application of a combination of technical, operational and organizational processes"*.[155] The NORSOK D-010 standard also requires management of well integrity throughout the life cycle of a well.[156]

A WIMS provides a framework for managing the risk 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. The key elements of a WIMS framework are:

- **risk assessment**, which includes techniques to:
  - identify the well integrity hazards and associated risks over the life cycle of the well;
  - determine acceptance levels for risks;
  - 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 (that is, a combination of components or practices that prevent or stop uncontrolled movement of well fluids);
  - methods to combine multiple barriers and redundancies to ensure reliability;
  - 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 the management system;
- **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 the acceptance criteria;

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[154] Connon and Corneliussen 2016; Smith et al. 2016; Sparke et al. 2011; Wilson 2015.
[155] ISO 16530-1:2017.
[156] NORSOK D-010.

- **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 management of change 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 summary of how different organisations have used WIMSs to manage their assets, the observed benefits, the technical challenges that were involved in their implementation, and the key lessons that were learned can be found in recent literature.[157] Wilson et al. provide recommendations and guidance for building an effective WIMS after taking into account the industry standards, local regulatory requirements and the organisation's needs.[158]

[157] Connon and Corneliussen 2016; Gell et al. 2015; Haga et al. 2009; Kumar et al. 2014; Smith et al. 2016.
[158] Wilson 2015.

8 Well integrity summary

Wells provide access to the shale gas resource to allow the controlled flow of the gas to the surface. Shale gas wells are drilled through the geological layers that overlie the shale resource. These layers will include permeable layers that contain aquifers or saline groundwater, as well as low-permeability layers that form natural barriers to vertical movement of fluid. However, wells may inadvertently provide potential pathways for the contamination of subsurface water and the release of fluids to the surface that include:

- unintended release of drilling muds, hydraulic fracturing fluids or gas from the well into aquifers or other groundwater bodies during well operations;
- unintended releases of fluids from the well at the surface; and
- migration of fluids along the well to other rock layers or to the surface.

Well integrity refers to how the well is constructed and operated to maintain safety, and to prevent these unintended releases of fluids to the environment or migration of fluid along the well. The concept of well barriers is fundamental to well integrity. Barriers prevent or stop uncontrolled fluid flow into, out of, or along the well. Physical barriers include casing and cement, drilling fluids, impermeable formations, well heads and BOPs. In addition to physical barriers, well integrity makes use of operational barriers (monitoring, work instructions and procedures), human barriers (competent personnel) and administrative barriers (standards and policies, and quality assurance).

Current industry practice for shale gas well design is to have at least two independent and verified physical barriers to maintain well integrity. A well integrity failure will therefore only occur if both physical barriers fail. If there is a multibarrier system, degradation or failure of one barrier will not lead to the release of fluids from the well. Such well barrier issues are often included in studies of well integrity in oil and gas wells, with rates of wells with a barrier issue of 1-10% reported. By contrast, studies that report on well integrity failure (all barriers failed), which is required for an actual release of fluids to the environment, show low rates of failure, typically less than one in 1,000.

The most commonly reported mechanism for well integrity failure is the migration of gas (predominately methane) along the outside of the casing, which shows that there is a pathway for flow. The buoyancy of gas provides the driving force for it to travel up these pathways. The gas may be sourced from any gas-bearing geological layer that the well passes through, and may originate from outside the shale reservoir. The presence of this pathway does not necessarily mean that other fluids (saline water, for example) will move between horizons, because this would also require sufficient pore pressure differentials between different rock layers to drive fluid flow. During production, pressures within a shale gas reservoir will be lowered, and any fluid flow is likely to be *towards* the reservoir rather than *away* from it. If there are saline groundwater layers in the overburden above the shale resource with pore pressures over the hydrostatic gradient, then some upward movement of this water may be possible. The rates of flow along the outside of the wellbore are likely to be low, even for gas, because of the limited size of the flow pathways.

The risk of fluid or gas migration along the outside of a well continues after the well has been plugged and abandoned, while other well integrity failure risks will no longer exist or will be significantly reduced. Although there are few studies of the long-term integrity of oil and gas wells, it is a topic of recent research for CO_2 geosequestration. The design and construction methods for wells for CO_2 geosequestration will be similar to those used in the oil and gas industry. Studies suggest that the cements used in well construction are likely to resist chemical and mechanical degradation, and maintain integrity for thousands of years, so long as the cement was appropriately designed and placed.

A well integrity failure may be catastrophic when there is a complete loss of control of the well that allows an inrush of formation fluids or gases, which then travel to the surface, resulting in a blowout. Blowouts are most likely to occur during drilling operations; they are potentially life-threatening for personnel working on the drill rig, and may also lead to release of fluids to the surface environment. The low permeability of shale gas resources reduces the inherent risk of blowouts in comparison with conventional oil and gas resources. Few blowouts have been reported in shale gas wells globally.

The risks associated with well integrity failure depend on how the well is constructed. For example, the risks of natural gas migration and contamination of shallow aquifers are increased when the surface casing does not extend below the base of these aquifers, or the production casing is inadequately cemented. Geological conditions are also important; for example, if there are shallow gas-bearing formations that may provide a source for gas migration along the well and overpressured layers that may drive fluid flow.

Current industry practice is to consider well integrity across the entire life cycle of the well. This approach recognises the fact that wells are often in operation for decades, and that actions at each phase have implications for well integrity in subsequent phases. The responsibilities for management of a well are often handed over to different teams within an organisation; therefore, a system that tracks well integrity is important for continuity. The implementation of WIMS is a fundamental component of this life cycle management, and allows well integrity to be tracked for each well in an operator's well inventory. The elements of a WIMS include risk assessment criteria; organisational structure (roles, responsibilities and competencies); well barrier design, verification and monitoring requirements; performance standards; and reporting requirements.

Shale gas wells are highly engineered, and well integrity is an important driver in their design, construction and operation. Each well must be designed to take into account its specific characteristics related to risk of integrity failure: characteristics such as the geology and the purpose of the well. Therefore, a WIMS outlines a process and objectives rather than prescribing particular design elements. Examples of leading operational practice in well integrity management can be found in ISO 16530-1:2017 on well integrity life cycle governance, NORSOK D-010 on well integrity in drilling and well operations, and the Norwegian Oil and Gas Association recommended guidelines.[159]

Hydraulic fracturing operations are conducted through wells, and place certain demands on well integrity due to the fluid pressures involved. These pressures may increase the likelihood of delamination of wellbore in the vicinity of the reservoir. However, engineering to withstand these pressures is a routine component of well design, and there are only a few examples globally of well integrity failure during hydraulic fracturing resulting in the release of fluids to the environment.

Other hydraulic fracture fluid pathways that could be created or dilated by the hydraulic fracturing operation include upward growth of hydraulic fractures and interaction of hydraulic fractures with natural faults. The literature suggests that the contamination of shallow aquifers via migration of hydraulic fracturing fluids from deep reservoirs in this way is highly unlikely where the vertical separation distance is large, as is likely to be the case in the Northern Territory.

The consequences of well integrity failures from shale gas development are likely to be less severe than those for conventional oil and gas resources. Shale gas resources have low reservoir deliverability,

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[159] ISO 16530-1:2017; Norwegian Oil and Gas 2016; NORSOK D-010.

which means that they cannot produce large volumes of fluids at a high rate. Conventional resources tend to have higher deliverability because each well accesses a larger reservoir volume of oil or gas and has a higher likelihood of overpressures. There have been several high-profile well integrity incidents on conventional oil and gas wells (the Montara and Macondo wells, for example) that have led to improvements to WIMSs in industry and regulation in many jurisdictions, including the Northern Territory. This increased focus on well integrity is also applicable to shale gas wells, and is likely to reduce the risks of well integrity incidents during the development of these resources.

The low rates of complete well integrity failure for shale gas developments reported in the literature have been achieved with current industry practices and regulatory frameworks, suggesting that well integrity risks are being addressed to a large extent during drilling and production. Longer term (post abandonment) well integrity and the potential for migration of gas along the outside of casing is not as well understood, and although the impacts of an individual well are likely to be small, this aspect warrants further investigation.

9 Regulatory frameworks for drilling and hydraulic fracturing operations

9.1 Well integrity regulatory frameworks in the Northern Territory

At the time the Inquiry was called in December 2016, the regulatory framework for petroleum activities in the Northern Territory was going through a process of reform in response to:

- the 2010 Montara Commission of Inquiry (**Montara Inquiry**);
- Dr Tina Hunter's review of the capacity of the Northern Territory's legal framework to regulate the development of an onshore petroleum industry (**2012 Hunter Report**); and
- the inquiries conducted by Dr Allan Hawke AC into the potential environmental impacts of hydraulic fracturing in the Northern Territory (**2014 Hawke Report**) and the environmental assessment and approval process (**2015 Hawke Report**).[160]

The regulatory framework was moving from a prescriptive approach to objectives-based regulation. This process started with the implementation of the Petroleum (Environment) Regulations (**PER**) to regulate environmental risks and impacts associated with petroleum activities. In its submission to the Inquiry, the Northern Territory Department of Primary Industries and Resources (**DPIR**), as the lead regulator, noted that two additional regulations were intended as part of the reform process to regulate exploration and production activities.[161] These regulations were also intended to be objective based and to follow the "as low as reasonably practicable" (**ALARP**) principle to manage risks, as adopted in the PER.

The current regulatory framework for petroleum activities consists of the *Petroleum Act* as the primary legislative instrument, supported by the PER, the Petroleum Regulations (which cover minor administrative aspects of resource management) and the Schedule of Onshore Petroleum Exploration and Production Requirements (**Petroleum Schedule**). The Petroleum Schedule is enforced by ministerial directive to licence holders; it regulates certain petroleum activities, drilling and hydraulic fracturing. The schedule is highly prescriptive and lacks flexibility. Hunter has recommended phasing out the Petroleum Schedule because it does not have the same legal force as regulation and does not align well with objective-based regulation.[162]

under the current regulatory framework, an operator must first obtain an exploration permit by application through a competitive process. Once a permit has been obtained, before any drilling or hydraulic fracturing activity can commence on a tenure, the tenure holder must obtain a petroleum project approval for those activities. To obtain such approval, the tenure holder must submit a project application for well drilling, workover or stimulation activities. The application is assessed by the DPIR Energy Division. In the DPIR's submission, they state that "T*he integrity of wells is a particular focus of*

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[160] Borthwick 2010; 2014 Hawke Report; 2015 Hawke Report; Hunter 2012. DPIR submission 226 p37.
[161] DPIR submission 226 p39
[162] Hunter 2016.

the Energy Division's assessment".[163] The assessment process has requirements that directly relate to well integrity, including:[164]

- **BOP** systems, BOP drills and a well control manual;
- minimum depths for the setting of surface casing, a requirement for the cementing of all casing strings to surface, and mandatory validation of casing and cement using cement bond logs;
- mandatory validation of all barriers by pressure testing, and mandatory formation integrity testing or leak-off tests;
- installation and testing of a completion tubing string (additional barrier); and
- all reasonable steps being taken to prevent communication between, leakage from, or the pollution of aquifers.

There are similar requirements for hydraulic fracturing activities, including:

- mandatory water quality testing, before, during and after the hydraulic fracturing;
- safe separation, through impermeable formations, between shallow aquifers and the hydrocarbon target zone (the section that is to be fractured);
- submission of fracture modelling confirming maximum **fracture height** and length (confirming safe separation);
- chemicals list for public disclosure on DPIR's website;
- use of pressure safety trip-out systems during fracture stimulation activities; such systems prevent exceedance of allowable pressure limits of surface pipework and downhole casing; and
- pressure monitoring confirming that well integrity has not been affected by fracture stimulation activities.

The tenure holder must also submit an environment management plan (**EMP**) for the activities that complies with the **PER** for assessment. One of the EMP requirements is a risk assessment of potential environmental impacts on aquifers from hydraulic fracturing, including baseline assessment of known aquifers, monitoring, modelling of fracture propagation and well completion schematics. There is overlap between the EMP requirements and the Petroleum Schedule.

If the tenure holder already has approval for project activities, the holder cannot vary from the approved program and must operate in accordance with any conditions of the approval. Approval for revised or additional activities requires an operational application.

The DPIR has implemented a process for the regulator to continually assess the integrity status of wells during drilling operations.[165] The *Well integrity verification form* and process was developed following the Montara Inquiry; it requires the assessor 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, and the well planning information submitted in the application for the drilling activity.

The Petroleum Schedule also has requirements for well abandonment. Wells cannot be abandoned in the Northern Territory without prior approval. The tenure holder is required to describe the plugging and abandonment program, and the procedures that will be used to validate the integrity of the barriers.

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[163] DPIR submission p29
[164] DPIR submission Attachment C
[165] DPIR submission p34

The DPIR has implemented a range of other measures related to well drilling and hydraulic fracturing in response to the Montara Inquiry and the Hawke reports of 2014 and 2015.[166] These measures include:

- increasing capability through recruitment of more petroleum engineers, training in well integrity and a mandatory CERT IV in Government Investigations;
- more robust approval assessment processes, with guidelines and checklists to increase the rigour of assessments, and a triple signatory and assessment approval system;
- introduction of additional prescriptive mandatory requirements that tenure holders must follow, including the requirement to cement all casing strings to surface; submission of fracture propagation models to illustrate separation between the stimulated zone and aquifers; and water monitoring before, during and after any hydraulic fracturing activities;
- improvement of transparency by requiring EMPs to be publicly available via DPIR's website;
- improvement of audit processes, with checklists for well drilling operations, hydraulic fracturing operations and well testing operations; and enabling of independent third-party inspectors, in addition to DPIR officers, to carry out operational and environmental inspections and audits through the Petroleum Schedule;
- implementation of the PER and associated processes; and
- a full review and update of the Petroleum Schedule in 2016.

A well operations management plan could operate in conjunction with an EMP, as recommended by Dr Tina Hunter.[167]

9.2 Well integrity regulatory frameworks in other jurisdictions

The regulatory framework for petroleum activities is objective based in Western Australia , the Commonwealth (offshore operations administered by the National Offshore Petroleum Safety and Environmental Management Authority, **NOPSEMA**) and South Australia. These jurisdictions do not have codes of practice for drilling or hydraulic fracturing operations; instead, they rely on the operator to identify hazards and manage risks according to the ALARP principle. The Commonwealth and Western Australian regulations are those that have most recently been updated, in 2016 and 2015, respectively. Both require the submission of a well operations management plan (**WOMP**, referred to as a well management plan in South Australia) for drilling. Relevant regulation in these two jurisdictions requires well integrity to be addressed in the WOMP. NOPSEMA provides guidance on the information required in the WOMP, and guidelines for applying the ALARP process to well integrity.[168] Neither jurisdiction has any prescriptive requirements about well design or well integrity. The Commonwealth regulations do, however, define reportable incidents for well integrity. Commonwealth and Western Australian regulations also provide for multiwell WOMPs to be created. Such WOMPs may be used for a group of wells in close proximity and with similar characteristics; for example, multiple directional wells drilled from a single location.

In South Australia, the long history of industry operation and regulation is worth noting. There are several operators with a long track record of operations, providing a track record of environmental and safety performance. The South Australia regulatory framework requires a statement of environmental objectives (**SEO**) to be developed on the basis of an environmental impact report that must be

[166] DPIR submission p37-45
[167] Hunter 2016.
[168] NOPSEMA 2016; NOPSEMA 2017.

conducted for all petroleum activities. The SEO describes how potential threats and risks of the specific activity on the environment will be managed. Approved SEOs effectively become project-specific regulations that are gazetted and made publicly available. SEOs are reviewed every five years, allowing for adaption to changing requirements and operational practices. The South Australia regulations also allow the classification of operators as requiring either high-level or low-level official surveillance. The classification is based on a rigorous audit and assessment process, and allows the regulator to place more emphasis on operators with less experience or those conducting novel activities. Before commencing activities, operators must submit an activity notification, and approval is granted based on an assessment of the operator's demonstrated capabilities and how the activities will be conducted to comply with relevant SEOs. This is largely similar to the WOMPs used by the Commonwealth and Western Australia. South Australia has no prescriptive requirements for well operations.

The Commonwealth, South Australia and Western Australia all have requirements for inspection or surveillance of field activities. All jurisdictions have a team of technical staff with expertise in petroleum operations to undertake assessment and inspection activities.

The New South Wales and Queensland regulatory frameworks are also largely objective based; however, both have codes of practice for coal seam gas drilling that are mandated in regulations.[169] Queensland also has a code of practice for other petroleum drilling, although this has not been made mandatory.[170] These codes were developed in close consultation with stakeholders, and are specific to the context of each jurisdiction. The codes are mandatory and include prescriptive requirements around process (requirements for matters to be considered during design of a well, for example) and some specific requirements for well construction and abandonment (surface casing setting depths and pressure testing of casing, for example). Santos supported the use of codes of practice in their submission to the Inquiry.[171] The Queensland codes of practice mandate the use of WIMSs.

[169] NSW Department of Trade and Investment 2012; QLD Department of Natural Resources and Mines 2017.
[170] QLD Department of Natural Resources and Mines 2016.
[171] Santos submission 168, p72.

10 Policy options for regulation related to well integrity

The following policy options address well integrity in the context of shale gas development in the Northern Territory, and need to be considered in the context of the overall regulatory framework for petroleum development. Local conditions are important in determining well integrity risks, and policy options must take into account the uncertainty that arises from the current limited amount of activity in shale gas resources in the Northern Territory to date.

10.1 Collection of baseline data

Baseline studies of **environmental receptors** are critical for assessing the performance of the industry. In the context of well integrity, appropriate baseline information should include measurements of shallow aquifer characteristics and surface hydrocarbon gas fluxes. The parameters that should be measured in shallow aquifers include water chemistry, water levels and hydrocarbon content (including isotopic composition, to provide indication of source). Similarly, baseline measurements of surface hydrocarbon gas flux should include characterisation of the chemical and isotopic compositions. The baseline characterisation of hydrocarbon gases will be important for understanding the occurrence of gas migration along the outside of casing (the most commonly reported well integrity failure mechanism). Harkness et al. provide a recent example of the techniques that can be used in integrated geochemical investigation of potential sources of natural gas and water contamination in a region with shale gas drilling activities, and demonstrate the value of baseline data.[172] Regional variability and the scale of proposed development will dictate the spatial density of the baseline measurements required.

10.2 Developing an understanding of well integrity risks in the Northern Territory

Onshore petroleum activity in the Northern Territory has been limited, with only 236 wells drilled as at October 2017. These wells have been drilled over a period of more than 50 years, and have primarily targeted conventional petroleum resources. The amount of data available from offset wells in the Northern Territory's prospective shale gas basins is limited. Similarly, the experience of the operators and regulators working with this resource is limited, although they bring experience from working in similar resources elsewhere. Although a great deal of knowledge of well integrity risk and its management is available from other jurisdictions, information on the characteristics of the Northern Territory's resources are an important input into the hazard identification process for well integrity management.

No shale gas projects in the Northern Territory have advanced past the exploration phase. If the moratorium is lifted, there will be a period of time as operators progress from exploration to appraisal. This increase in activities provides an opportunity for adaptive regulation through an objective-based

[172] Harkness et al. 2017.

regulatory regime. Setting prescriptive regulatory requirements based on limited data and experience may not allow risks to be managed effectively as additional information on local hazards is discovered. Therefore, an objective-based regulatory regime that recognises the uncertainty may be a more appropriate way of managing the risks.

During the early stages of shale gas developments, there may be an opportunity for collaboration between operators, to share relevant data on well integrity. Although the regulator receives data from operators soon after wells or geophysical surveys are completed, these data are not made public for a period of time. Basic information in well completion reports is kept confidential for 2 years and 28 days from the date of rig release (that is, when the drill rig is demobilised at the completion of drilling activities), and geophysical data is kept confidential for a period of 3 years. Interpreted data are not released for a period of 6 years from when they are collected. There may be a role for the regulator to facilitate the early sharing of data relevant to well integrity hazard identification and risk assessment between operators and with other stakeholders. This could be through a simple data exchange, or the regulator could coordinate the development of a basin-wide well integrity management approach.

Development of a basin-wide approach to well integrity management that involves the regulator, all operators in the basin, independent advisers and other stakeholders may provide a means of reducing risks and accelerating the development of leading practices for the region. This process could facilitate the sharing of baseline environmental survey methods and data, information on well integrity hazards and operational practices for well integrity management.

10.3 Requirement for well integrity management throughout the well life cycle

The prevention of well integrity failures throughout the life cycle of a well requires active management, and many jurisdictions require operators to demonstrate that they have a WIMS that takes into account well integrity throughout the well life cycle. The management of integrity for individual wells should be conducted within a system for managing well integrity for all of the operator’s well stock. There are several international standards that set out well integrity management processes, and well integrity management methods are continually improving. Policies should allow or require operators to continually update their processes, to keep up to date with evolving industry practices and standards. Independent certification against these international standards by recognised classification societies could also be part of demonstrating the standing of an operator’s well integrity management processes. There are multiple points at which compliance with this requirement could be evaluated, including the assessment of the technical capacity of applicants during permit application, renewal or amendment processes; during the approval process for well drilling and associated activities (such as hydraulic fracturing or abandonment); or during periodic review of an operator’s performance.

A comprehensive policy on well integrity management will also set out the regulator’s responsibilities for review and assessment of an operator’s well integrity management approach, and for an inspection regime to ensure compliance. The policy should also state the operator’s reporting requirements for well integrity incidents, and should set out penalties for non-compliance.

In addition to a WIMS, 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 Western Australian regulations require well management plans that outline the risk assessment approach used, the risks identified and the well integrity management practices that will be put in place to be submitted to the regulator for assessment. The current project application process for drilling activities in the Northern Territory requires the operator to describe components of well integrity management, but does not explicitly require an overall well integrity management plan for the full life cycle of a well.

10.4 Considerations for codes of practice, guidelines and minimum standards

The intention of the regulator in the Northern Territory is to adopt an objective-based regulatory regime, with regulations for petroleum exploration and production alongside the PER. These regulations would be supported by guidelines (which already exist for the PER), and codes of practice that would assist in the interpretation and implementation of the regulations by operators and regulators. The content of a code of practice around well integrity or well construction and abandonment for the Northern Territory will depend on the structure of relevant regulations. The Commonwealth (NOPSEMA) and Western Australian regulatory frameworks provide examples of recently implemented objective-based regulation. In regard to well integrity, the guidelines in these jurisdictions set out what a well management plan must contain, but do not prescribe minimum technical requirements. The operator must demonstrate that they are managing risks in accordance with the ALARP concept. In contrast, the codes of practice developed in New South Wales and Queensland contain many prescriptive elements.

Consideration must be given to the interaction between prescriptive components of a code of practice and the ALARP concept that is integral to objective-based regulation. Based on the well integrity risks identified in this report, the following items could be prescribed through regulation or associated guidelines and codes of practice to be included in a well management plan for the Northern Territory:

- requirement for a well integrity management plan that includes consideration of:
  - well integrity management across the well life cycle;
  - the operator’s process for managing well integrity risks;
  - how well integrity hazards are identified, and risks assessed and managed;
  - well barrier plans throughout the life cycle, performance standards and a verification approach;
  - reporting and documentation;
  - change management;
- requirements to characterise aquifers, saline water zones and gas-bearing zones in the overburden during drilling;
- how the well design and operation will provide protection of aquifers;
- requirements to monitor for methane migration along the outside of casing; and
- requirements to verify the integrity of the bond between casing, cement and the formation, periodically and before abandonment.

The New South Wales and Queensland codes of practice were developed in consultation with industry and other stakeholders. A similar consultative approach that draws from the basin-wide well integrity management approach outlined in Section 10.2 is recommended for the Northern Territory. This approach can be used to identify whether any minimum standards should be put in place.

10.5 Developing leading well abandonment practices for the Northern Territory

Although the objectives of abandonment are clear, the long-term integrity of shale gas wells post abandonment is uncertain. There has been little monitoring of well integrity post abandonment and, where integrity issues have been found, it has been difficult to investigate the causes. Effective well abandonment requires wells to have integrity at the end of their operating life. It is important to consider the post-abandonment integrity requirements as part of the design of the well and management of its integrity, and this is part of the reasoning for the policy option set out in Section 10.3. The impacts of well integrity failure post abandonment are likely to be small on a well-by-well basis, with the main risk being migration of gases along the outside of the casing.

Given the current state of shale gas development in the Northern Territory, it is unlikely that a large number of wells will be abandoned in the near future. This provides an opportunity to determine appropriate practices for abandonment of shale gas wells in the Northern Territory, by establishing a long-term abandonment assessment program. This program could assess well abandonment options in the context of the Northern Territory's shale resources, and could be conducted in conjunction with the basin-wide well integrity management approach outlined in Section 10.2. The difficulty of remediating integrity issues in abandoned wells means there must be an emphasis on abandonment practices that will reduce the risk. A long-term abandonment assessment program could consider:

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

Well abandonment is a global issue, with estimates that about 30,000 wells will need to be plugged and abandoned globally over the next 15 years.[173] DNV GL (an international accredited registrar and classification society) has recently developed guidelines for risk-based abandonment of offshore wells.[174] Well abandonment practices are likely to see a good deal of innovation as the scale of abandonment activity increases globally and there is increased scrutiny of environmental performance.

The Northern Territory currently does not allow wells to be abandoned without prior approval (according to the Petroleum Schedule, Clause 328 (1)). The requirement for approval for abandonment of a well and for the operator to outline the approach to well abandonment and the maintenance of well integrity post abandonment will reduce risk associated with abandoned wells.

10.6 Providing transparency to address community concerns

Well integrity is often raised as an issue by the broader community, and this was reflected in many of the submissions to the Inquiry from both advocacy groups and private individuals.[175] Greater

[173] Ouyang and Allen 2017.
[174] DNVGL-RP-E103.
[175] Arid Lands Environment Centre, Submission 411, (Arid Lands Environment Centre submission), p3; Lock the Gate Alliance, Submission 171, (Lock the Gate Alliance submission), p21; Carol Randall and Andrew Smith, Submission 395, (C Randall and A Smith submission), p7; Rod Dunbar, Submission 297, (Dunbar submission), p3

confidence in regulatory processes can often by developed through inclusive participation of stakeholders, the implementation of transparent processes and open communication.[176] Transparency requires open publicly available communication about the well integrity process, including details of the process, roles and responsibilities of regulators and operators, and the information used within the process to make decisions.[177] The basin-wide well integrity management approach outlined in Section 10.2 provides a mechanism through which the community can participate in well integrity management. This approach would allow stakeholders to have input into the identification of the well integrity issues that must be managed; it would also make publicly available information on well integrity hazards and risk assessments for basins prospective for shale gas in the Northern Territory.

The requirement for EMPs to be published provides a level of transparency around the management of environmental risks. Should WOMPs be used in the Northern Territory, consideration should be given to making at least the well integrity management component of these plans publicly available. Also, consideration should be given to making a well integrity summary for all wells in the Northern Territory publicly available. These summaries could contain the current well barrier schematic (similar to the one shown in Appendix 2) along with a statement of the status of the barriers in the well, and could be accessible through the Spatial Territory Resource Information Kit for Exploration (STRIKE) web-mapping tool. Interested stakeholders could then easily see the current well integrity status for wells in a region.

A simple mechanism for public complaints should also be available. This system could be for complaints about any aspects of shale gas development, not just well integrity issues. There are several examples of such systems in other jurisdictions around the world.[178]

10.7 Avoiding legacy issues

Wells that are suspended (that is, not in production and yet to be abandoned) may present an unnecessary well integrity risk. When there are legitimate reasons for a well to be suspended, it is crucial that well integrity continues to be actively managed. The Northern Territory currently only allows wells to be suspended for two years at a time (According to the Schedule, Clause 328 (5)(e)). This is a similar approach to the ‘idle iron’ policy adopted for offshore wells in the Gulf of Mexico, according to which wells must be abandoned within five years of production ceasing.[179] The requirement for approval for suspension of a well, along with the time limit, and requirements for the operator to outline the well integrity management and monitoring of the suspended well, will reduce risk by ensuring that wells are only suspended with good reason and that their integrity is maintained while they are suspended.

[176] Dietz and Stern 2007.
[177] Dietz and Stern 2007.
[178] For example Queensland’s CSG Compliance Unit https://www.business.qld.gov.au/industries/mining-energy-water/resources/land-environment/landholders/monitoring-complaints; Colorado’s Oil and Gas Conservation Commission http://cogcc.state.co.us/complaints.html#/complaints.
[179] US Bureau of Ocean Energy Management 2010.

11 Conclusions

Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface. Well integrity is established via the use of barriers that prevent these unintended fluid flows. For shale gas wells, a two-barrier principle is applied, whereby at least two independent and verified barriers are in place. Unintended or uncontrolled fluid flow will only occur if both barriers fail, resulting in failure of the integrity of the well.

Well integrity and its management throughout the life cycle of the well is important for the safe, efficient and environmentally sustainable development of shale gas resources. Potential hazards to the integrity of a well can relate to the purpose of the well, the way it has been constructed, and the characteristics of the resource and the overlying geology.

The characteristics of shale gas resources mean that there is a low likelihood of catastrophic well integrity failures (such as blowouts) that result in a release of drilling or formation fluids to the surface environment and a potentially hazardous release of gas. Specifically, the low permeability of shale resources limits the rate at which fluids can enter the well, decreasing but not eliminating the risk of catastrophic well integrity failures.

The most plausible environmental risk related to shale gas well integrity is from the migration of gas up the outside of the well. This gas may originate from the shale gas resource or from gas-bearing layers in the rock layers that overlie it. The rates of gas leakage for individual wells are likely to be small because of the small cross-sectional area and long length of leakage pathways; however, the cumulative effects from a large number of wells may be significant. This risk is also present after wells have been abandoned, and there is limited data on the long-term integrity of shale gas wells.

Subsurface risks associated with hydraulic fracturing relate primarily to the impacts of hydraulic fracturing on the potential for gas migration up the outside of the well. The potential for hydraulic fracturing fluid to reach shallow aquifers via other mechanisms – such as excessive vertical growth of hydraulic fractures or hydraulic fracture intersection with existing structures – is considered to be low.

There is limited published data on rates of well integrity failure in shale gas developments globally. The data available indicate that failure rates are at the lower end of those for other oil and gas wells.

The risks posed by well integrity issues require proactive management of well integrity. The industry and regulators have increasingly focused on well integrity over the past decade, to improve safety and environmental performance. In particular, the focus has been on managing well integrity across the life cycle of the well, with operators now routinely deploying WIMSs. These systems allow the integrity of wells to be managed across their entire life cycle so that the risks can be managed. WIMSs involve:

- identification of hazards and assessment of risks;
- clear identification of well barriers at every phase of the well's life cycle;
- performance standards for well barriers and their components;
- verification procedures for well barriers against the performance standards; and
- an organisational approach to well integrity management that includes identification of roles and responsibilities, and processes for continuous improvement, change management and audit.

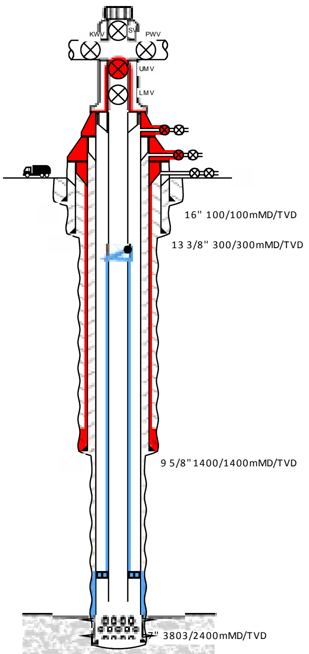
Although global experience in shale gas development provides useful evidence of well integrity risks and their management, there is limited experience in the Northern Territory's onshore gas resources because of the nascent stage of the industry. A basin-wide well integrity management approach that facilitates the sharing of data and well integrity management approaches between operators, regulators and other stakeholders may prove useful in reducing well integrity risks, should an onshore gas industry develop. This approach would allow industry to develop leading practices appropriate for the risks identified in the Northern Territory's shale gas resources. Methods for ensuring the long-term integrity of wells post abandonment could also be explored, helping to reduce the uncertainty around this phase of the well life cycle. Baseline studies to characterise environmental receptors before shale gas activities start will be important to assist in any future evaluation of the environmental impact of the industry.

A regulatory framework that addresses well integrity risks and other subsurface risks during drilling and hydraulic fracturing activities will need to provide a balance between providing guidance on the identification and minimisation of risks while allowing operators to adopt better practices as they are developed.

Appendix A Example well barrier schematic

WELLBARRIER

Field	: Csiro		
Well	: 01		
Schematic	: WB.D 4.1-a1 rev. 1	Prepared by	: Tore Fjågesund (u)
Date	: 23.Oct.2017	Verified by	:



Depth reference: Landrig, unspecified depth reference

Graphics by Wellbarrier

Producer

Gas producer

Draft

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test to xxx Bar	Periodic inflow testing
Tubing	Pressure test to xxx Bar	A-annulus pressure
Production packer	Pressure test to xxx Bar	A-annulus pressure
Production casing	Pressure test to xxx Bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure

Secondary barrier elements

Element	Qualification	Monitoring
Surface x-mas tree	Pressure test to xxx Bar	Periodic testing
Spool wellhead B with access valve	Pressure test to xxx Bar	External observation and periodic testing ov valves
Spool wellhead A with access valve	Pressure test to xxx Bar	External observation and periodic testing of valves
Casing hanger	Pressure test to xxx Bar	C-annulus pressure
Intermediate casing	Pressure test to xxx Bar	C-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	C-annulus pressure

Healthy well, no or minor issue

Note :

Glossary

Term	Description
Abandonment	Ceasing efforts to produce fluids (oil or gas) from a well and plugging the well without adversely affecting the environment.
Annulus	The gap between any of the following: tubing and casing, two casing strings, or casing and wellbore. The annulus between the tubing and casing is the primary path for producing gas from coal seam gas wells.
Aquifer	An identifiable stratigraphic formation that has the potential to produce useful flows of water and may include formations where, due to hydraulic fracturing activity, a changed hydraulic conductivity allows such water flows.
Blowout	A sudden and uncontrolled escape of fluids to the surface from the wellbore.
Blowout preventer	A large valve or mechanical device placed at the top of a well that can be used to seal and regain control of the well in the case of a blowout.
Borehole	Generally refers to a narrow, artificially constructed hole drilled for purposes other than production of oil, gas or water (for example, to intercept, collect or store water from an aquifer; to passively observe or collect groundwater information; or to undertake mineral exploration). Also known as a bore, drill hole or piezometer hole.
Borehole breakouts	Enlargement and elongation of a borehole cross-section in a preferential direction. Formed by the break up of the wall of the wellbore in a direction parallel to the minimum horizontal stress.
Brine	Saline water with a total dissolved solid concentration greater than about 40,000 ppm. Sea water has total dissolved solids of around 30,000 ppm.
Casing	Steel pipe used to line a well and support the rock. Casing extends to the surface and is sealed by a cement sheath between the casing and the rock.
Casing shoe	A short adaptor that fits on the downhole end of the casing string, to facilitate insertion of the casing into the well.
Casing string	Steel pipe used to line a well and support the rock. The casing extends to the surface and is sealed by a cement sheath between the casing and the rock. Often, multiple casings are used to provide additional barriers between the formation and well.
Catastrophic barrier failure	A complete loss of control of the well that allows an inrush of formation fluids or gases, which then travel to the surface, where they are released to the environment.
Cement sheath	A cement ring in the annulus between the casing and the wellbore, or between two casing strings.
Coal seam gas (CSG)	A form of natural gas (generally 95-97% pure methane, CH_4) that is typically extracted from permeable coal seams at depths of 300-1000 m. Also called coal seam methane or coalbed methane.

Decommissioning	The process used to remove a well or other infrastructure from service.
Drilling mud	Also known as drilling fluid, provides cooling and lubrication to the drill bit and drill string, lifts drill cuttings from the well and is a component of well control.
Environmental receptors	Living organisms, habitats or natural resources that may be adversely affected by environmental contamination.
Exploration well	A well that is drilled to test for: • the presence of oil or gas; • natural underground reservoirs suitable for storing oil or gas; or • obtaining stratigraphic information for exploring for oil or gas.
Flowback	Allowing fluids to flow from the well following a hydraulic fracturing treatment. Flowback fluid is composed of a mixture of hydraulic fracturing fluid and formation fluid.
Formation fluid	Any fluid within the pores of the rock. May be water, oil, gas or a mixture. Formation water in shallow aquifers can be fresh. Formation water in deeper layers of rock is typically saline.
Formation pore pressure	The pressure in the porous rock around the well.
Fracture gradient	The pressure required to induce fractures in rock at a given depth.
Fracture height	The distance between the top and bottom of the fracture.
Fracture width	Fracture width is the separation between the two faces of the fracture. Its value is largest at the wellbore and tapers towards the tip of the fracture.
Gas migration (GM)	Flow of gas along the annulus between casing strings, cement and the formation.
Geochemical	Relating to the chemistry of geological material (rocks, the Earth).
Groundwater	Water occurring naturally below ground level (whether in an aquifer or other low-permeability material), or water occurring at a place below ground that has been pumped, diverted or released to that place for storage. Does not include water held in underground tanks, pipes or other works.
Hazard	Inherent property of an agent or situation having the potential to cause adverse effects when an organism, system or population (or subpopulation) is exposed to that agent.
Horizontal drilling	Drilling of a well in a horizontal or near-horizontal plane, usually within the target formation. Requires the use of directional drilling techniques that allow the deviation of the well on to a desired trajectory. Horizontal wells typically penetrate a greater length of the reservoir than a vertical well, significantly improving production while minimising the surface footprint of drilling activities.
Hydraulic conductivity	A coefficient of proportionality describing the rate at which a fluid can move through a permeable medium.

Hydraulic fracturing	Also known as 'fracking', 'fraccing' or 'fracture simulation', this is a process by which geological formations bearing hydrocarbons (oil and gas) are 'stimulated' to increase the flow of hydrocarbons and other fluids towards the well. In most cases, hydraulic fracturing is undertaken where the permeability of the formation is initially insufficient to support sustained flow of gas. The process involves the injection of fluids, proppant and additives under high pressure into a geological formation to create a conductive fracture. The fracture extends from the well into the production interval, creating a pathway through which oil or gas is transported to the well.
Hydraulic fracturing fluid	The fluid injected into a well for hydraulic fracturing. Consists of a primary carrier fluid (usually water or a gel), a proppant such as sand and one or more additional chemicals to modify the fluid properties.
Impact	The difference between what would happen as a result of activities and processes, and what would happen without them. Impacts can be changes that occur to the natural environment, community or economy. They can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes.
Injection well	A well used to inject fluid into the subsurface. This may be for waste water disposal, enhanced oil recovery, gas storage, or CO_2 sequestration.
Lost circulation	The reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string.
Microannulus	See 'Annulus' above.
Offset well	An existing well in close proximity to a proposed well. An offset well may provide information for the planning of a new well, or may be imacted by the drilling of a new well.
Openhole	An uncased section of a well.
Overburden	Material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials such as ores or coal, especially those deposits that are mined from the surface by open-cut methods.
Overpressure	Occurs when the pore is higher than the hydrostatic pressure, caused by an increase in the amount of fluid or gas in the rock, or changes to the rock that reduce the amount of pore space. If the fluid cannot escape, the result is an increase in pore pressure. Overpressure can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure
Packer	A device that can be run into a well; the device has a small initial outside diameter and is expanded inside the well to seal the wellbore. Used to isolate zones within a well in applications such as multistage hydraulic fracturing.
Perforation	A channel created through the casing and cement in a well to allow fluid to flow between the well and the reservoir (hydraulic fracturing fluids into the reservoir, or gas and oil into the well). The most common method uses perforating guns equipped with shaped explosive charges that produce a jet.

Permeability	The measure of the ability of a rock, soil or sediment to yield or transmit a fluid. The magnitude of permeability depends largely on the porosity and the interconnectivity of pores and spaces in the ground.
Plug	A mechanical device or material (such as cement) placed within a well to prevent vertical movement of fluids.
Plugged and abandoned	A well that has been permanently closed, with plugs inserted to isolate sensitive formations and aquifers, and surface infrastructure removed.
Pore pressure	The pressure of formation fluids in pores within rock in the subsurface.
Porosity	The proportion of the volume of rock consisting of pores, usually expressed as a percentage of the total rock or soil mass.
Preferential flow	The uneven and often rapid and short-circuiting movement of water and solutes through porous media (typically soil), characterised by small regions of enhanced flux (such as faults, fractures or other high permeability pathways), which contributes most of the flow, allowing much faster transport of a range of contaminants through that pathway.
Pressure test	A method of testing well integrity by raising the internal pressure of the well up to maximum expected design parameters.
Principal stress	The stress component perpendicular to a given plane, which may be compressional or tensional (that is, there is no shear stress component). Also known as normal stress.
Produced water	Water brought to the surface via a well; in the case of coal seams, water that is pumped out of the seams to release the natural gas during the production phase. Some of this water is returned fracturing fluid and some is natural 'formation water' (often salty water that is naturally present in the coal seam). This produced water moves back through the coal formation to the well along with the gas, and is pumped out via the well head.
Production zone	The section of a well from which fluids or gas are produced.
Proppant	A component of the hydraulic fracturing fluid system comprised of sand, ceramics or other granular material that 'prop' open fractures to prevent them from closing when the injection is stopped.
Reservoir	A geological formation with adequate porosity, fractures or joints that can store hydrocarbons.
Risk	The probability of an adverse effect in an organism, system or population (or subpopulation) caused under specified circumstances by exposure to an agent.
Seismic survey	A method for imaging the subsurface using controlled seismic energy sources and receivers at the surface. Measures the reflection and refraction of seismic energy as it travels through rock.
Shale gas	Natural gas that is generally extracted from a fine grained sedimentary rock that has naturally low permeability. The gas has usually formed in place (source rock is the reservoir).

Stress	Force applied to a body with units of force per area. Rocks within the earth are subjected to stresses caused by the weight of overlying rocks and tectonics (movement within the earth).
Surface casing vent flow (SCVF)	Flow of gas from a vent in the annulus between surface casing and other casing strings in a well.
Sustained casing pressure (SCP)	Sustained pressure in the annulus between casing strings.
Tight gas	A gas resource in very low permeability reservoir rock. The reservoir usually requires stimulation (hydraulic fracturing) to enable economic production. Shale resources are differentiated from tight gas resources based on their rock type.
Tubing	Steel pipe that is hung inside the casing. The tubing string may have a pump installed at its lower end and, for pumped wells, is a primary path for producing fluids from coal seam gas wells.
Thermogenic	Produced by a thermal process. Shale gas and oil are typically thermogenic and are produced by thermal maturation of organic matter.
Unconventional resource	Petroleum (oil and gas) resources that cannot be developed using conventional oil and gas technologies. Includes coal seam gas, shale gas and oil, tight gas and basin centred gas.
Washout	An enlarged region of a wellbore. A number of factors can cause this, such as excessive bit jet velocity, soft or unconsolidated formations, and in situ rock stresses.
Well	A hole drilled in to the earth from which petroleum or other fluids can be produced.
Wellbore	The hole produced by drilling, with the final intended purpose being for production of oil, gas or water.
Well barrier	Envelope of one or several dependent barrier elements (including casing, cement, and any other downhole or surface sealing components) that prevent fluids from flowing unintentionally between a bore or a well and geological formations, between geological formations or to the surface.
Well breach	Failure in cement, casing, downhole or surface sealing components.
Well deviation	The angle at which a wellbore diverges from vertical.
Well head	The surface infrastructure that controls pressure and access at the top of a well.
Well integrity	Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface.
Well integrity failure	May result from a well breach (or a number of well breaches), and can take the form of a hydrological breach (fluid moves between different geological units) or an environmental breach (fluid leaks from the well at the surface or contaminates water resources).
Well logging	The process of recording a signal from a geophysical tool run into a well.

Well pad	The area of land on which the surface infrastructure for drilling and hydraulic fracturing operations are placed. The size of a well pad depends on the type of operation (e.g. well pads are larger at exploration than at production).
Workover	The restoration or stimulation of a production well to restore, prolong or increase the production of oil or gas.
Zonal isolation	Exclusion of fluids such as water or gas in one zone from mixing with fluids in another zone.

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