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Bore and well induced inter-aquifer connectivity: a review of literature on failure mechanisms and conceptualisation of hydrocarbon reservoir-aquifer failure pathways

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CSIRO Land and Water

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Executive Summary

The project "*Bore and well induced inter-aquifer groundwater connectivity: Consequence modelling and experimental design*" focuses on identifying the consequences associated with preferential pathways generated by failed or open bore holes associated with coal seam gas development. The project aims to develop methodologies and techniques that will identify and potentially quantify the potential risks associated with well and bore-induced inter-aquifer connectivity. The project has two components: i) a critical literature review and local groundwater modelling to identify the types of compromised bore integrity that may be measureable in CSG-bearing basins, and ii) regional groundwater modelling to assess the consequences of well and bore hole connectivity and the number of required connective pathways to create a range of noticeable impacts. This report represents the literature review that provides the framework to guide local-scale simulations to establish i) the potential for local-scale impacts of well or bore failures, ii) the level of discharge or cross-formational leakage that would be required to produce measurable changes in groundwater chemistry (major ions, stable isotopes or tracers), and iii) experimental designs that could be applied to measure local impacts of wells or bores that may have failed.

This review addresses some aspects of well failure, such as failure mechanisms, failure rates and knowledge gaps in the context of understanding the potential impacts of well failure on aquifer connectivity in CSG (coal seam gas) producing environments. Onshore oil and gas wells, water bores as well as coal seam gas wells are included in this review.

Well failure or loss of well integrity may result from a well breach (or number of well breaches), and can take the form of a hydrological or environmental breach. The three types of breaches are defined as:

- Well breach – failure in cement, casing, downhole and surface sealing components
- Hydrological breach – fluid movement between different geological units, or
- Environmental breach – fluid leaks at surface and causes contamination of water sources.

Key well failure mechanisms are addressed for each phase of an entire well life cycle, i.e., well design and/or construction, production and abandonment phases and have been summarised below.

Well design and/or construction phase

Failure mechanism relevant for the well design and/or construction phase are:

- Well design and/or construction that is inadequate to prevent hydrological or environmental breach; includes lack of casing and/or annulus seal, and, in case of a water bore, screening across multiple aquifers;
- Well failure that may occur during or as a consequence of i) drilling fluid being lost into overburden and reservoir formations due to naturally fractured formations or high drilling fluid pressure that generates a hydraulic fracture unintentionally, or ii) fluid influx into the well from the surrounding formations due to the drilling fluid pressure being lower than the formation pore pressure;
- Wellbore instability may occur due to a lower drilling fluid pressure than required. Wellbore instability not only produces washout that can lead to a poor cement job, but also creates a disturbed zone with enhanced permeability surrounding the well;
- Failure in cement sheath and cement bond integrity may lead to well failure. Cement sheath and cement bonds play a critical role in protecting casing from corrosion and in preventing fluid migration behind the casing. The factors that can affect cement sheath and cement bond integrity include cement slurry losses into formations, poor wellbore condition, poor mud conditioning, pressure cycles imposed on casing and cement sheath during casing pressure test, and cement degradation.
- Tubing/casing corrosion resulting in well failure. Corrosion attacks every metal component, including tubing and casing, if unprotected in all phases in the life of an oil and gas well.

Production phase

In addition to the tubing/casing corrosion and cement related failure mechanisms, and possible leaks from wellhead and other surface equipment, well failure could be induced by reservoir compaction due to depletion in reservoir pressure in conventional oil and gas wells, such as:

- Well shear damage as a result of reservoir compaction induced geomechanics effects in overburden and at top of production interval.
- Well compression and buckling damage within the production interval.
- Development of flow pathways between the production interval and existing transmission faults or the wellbore annulus through hydraulic fracturing.

Furthermore, depressurisation within hydrocarbon reservoirs can lead to gas migration through compromised/uncemented wells, water bores, natural and/or induced fractures. Especially at some distance from the edge of the depressurised zone, the force of buoyancy of the free gas will overcome that of the pressure gradient towards the CSG production well, and the free gases will tend to move away from the production well in the updip direction, potentially making its way through compromised wells or bores.

Abandonment phase

Potential leakage pathways for abandoned wells include:

- Interfaces between cement and casing, and between cement and formation due to well stress and pressure cycles during well-life operation
- Within the cement sheath due to poor quality, fractured or degraded cement sheath
- Across the casing due to corroded casing or fluid flow through casing connections
- Mixing of water from alluvial, confined and production zone aquifers in wellbores repurposed for water extraction

It should be noted that occurrence of the above failure mechanisms for a particular well does not necessary lead to lost integrity of the well, i.e. a hydrological or environmental breach. This would depend on the extent of the failure mechanisms along the well and specific geological conditions.

Well failure rates were reviewed based on three large international datasets from the US and Canada for conventional onshore oil and gas and coal seam gas wells. The review further included one dataset on CSG well integrity failure in Queensland, Australia, and one dataset on water bore integrity in the Surat basin, Australia. Two further studies considered offshore oil and gas wells, one in the Gulf of Mexico (US) and one offshore Norway. Caution should be exercised when using failure rates reported for overseas onshore/offshore oil and gas wells or from shale gas wells to estimate CSG well failure rates under Australian conditions. Because oil and gas and shale gas wells are drilled to much greater depth than CSG wells, they are subject to higher temperatures and pressures and have more casing layers. As a result, their failure rates are expected to be higher than for CSG wells. Nevertheless, the findings from conventional oil and gas and shale gas wells are useful in gaining understanding of possible failure mechanisms potentially relevant to CSG wells, and for estimating upper bound failure rates.

A low-end estimate on conventional oil and gas well failure rates in Ohio and Texas, USA:

- Estimates of well barrier failure rates ranged from 0.035 to 0.1% for a well population over 250,000, whereas complete well failure rates are estimated to be one order of magnitude lower
- Hydraulic fracturing of over 16,000 wells did not cause well failure and groundwater pollution.

Oil and gas well failure rates in Alberta, Canada:

- The percentage of the wells with surface casing vent flow and gas migration outside the surface casing to the entire well population over 350,000 was 4.5%

Coal seam gas well failure rates (with casing head pressure greater than 0.172 MPa (25 psi)) in San Juan Basin, USA:

- The well failure rate in La Plata County was estimated to be approximately 3.4% for more than 1000 coal seam gas wells during the period between 1991 and 2000
- The well failure rates in Ignacio-Blanco field ranged from 1.3% to 8.6% during the period between 1992 and 2010 with an average of 3.6%. The total number of coal seam gas wells subject to casing head pressure measurement averaged approximately 400 per year.

Coal seam gas well integrity in Queensland, Australia:

- The risk of a subsurface breach of well integrity was assessed to be very low to near zero and involved more than 6700 CSG wells inspected from 2010-2015.

Water bore integrity in the Surat Basin, Australia:

- The bores with steel casing constructed prior to 1968 are considered to have poor integrity, i.e., the wells are assumed to have failed. This assumption is based on an estimated service life of 45 years for steel (optimistic value)
- The failure rate cannot be established for bores constructed since 1968, but given the estimated service life of 45 years for steel cased bores, many are expected to have reached a significant level of corrosion.

The review on well failure mechanisms and well failure rates identified a number of knowledge gaps, in particular about:

- Well failure criteria: there is no quantification of an acceptable minimum rate of fluid released from a well that has a negligible impact on the environment, recognising that any rate would be highly site specific
- Well failure rate: there are currently few data/information publically available to establish well failure rates for CSG wells across all gas production fields in Australia
- Impacts of well-life stress and pressure on the integrity of cement sheath and cement bonds, which are not well understood
- Impacts of reservoir compaction induced by depressurisation/dewatering in coal seams on the integrity of cement sheath and cement bonds
- Long-term (100-1000 years) cement durability and degradation rate under typical CSG well downhole conditions in Australia
- Better information is required on effective wellbore permeability, especially for exploration bores or decommissioned wells and for Australian conditions.

The study subsequently focused on the conceptualisation of preferential flow pathways for use in local-scale and regional-scale groundwater modelling. Major pathways for movement of groundwater between strata have been identified and have been linked to failure of: i) uncased exploration bores backfilled with rock material upon decommissioning, ii) cemented production wells plugged with cement cores upon decommissioning, iii) wellbores during hydraulic fracturing, and iv) oil and gas wells repurposed for water extraction and water bores in which casing has corroded and/or there is no cementing of the annulus. Flow through leaky wellbores may be represented in groundwater models through a Darcy-type flow conceptualisation, using the effective hydraulic conductivity of the wellbore.

A compilation of US studies of abandoned oil and gas production bores revealed cement porosity has a log-linear relationship with cement hydraulic conductivity, and effective wellbore conductivity (from 10^{-11} to 10^{-6} m/s) was found to be considerably greater than cement core conductivity (from 10^{-12} to 10^{-8} m/s). The latter finding indicates the wellbore has preferential flow pathways in addition to slow matrix flow through the more unperturbed cement sections of the wellbore annulus.

Flow through leaky wellbores and abandoned exploratory bores may also be calculated from equations developed for flow through conduits, for either laminar or turbulent flow conditions.

The study also includes an evaluation of existing groundwater modelling software and their fitness-for-purpose regarding flow through leaky wells, wellbores and abandoned exploratory bores. As far as the industry standard groundwater modelling software is concerned, the Connected Linear Network (CLN) module package in MODFLOW-USG was identified to have the required capability to model passive water flow through leaky wellbores for a fully saturated medium (single-phase water flow). For cases where dual-phase flow occurs, especially within the CSG well fields, a dual-phase flow simulator may be more appropriate although its regional-scale implementation across potentially hundreds or thousands of wells may be computationally very demanding.

Abbreviations

General abbreviations	Description
APPEA	Australia Petroleum Production and Exploration Association
BHTP	Bottom hole treating pressure
BLM	Bureau of Land Management, U.S. Department of the Interior
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DNRM	Department of Natural Resources and Mines, Queensland
ECD	Equivalent circulation density for drilling fluid
EPA	Environmental protection agency
ERCB	Energy Resources Conservation Board, Government of Alberta, Canada
FIT	Formation integrity tests
GM	Gas migration
LOT	Leak-off tests
LCM	Lost circulation materials
m_w	Mud weight
P_{pore}	Fluid pressure inside the pore space of rocks
$P_{breakdown}$	Rock formation breakdown pressure
PKN	Perkins-Kern-Nordgren model
PVC	Polyvinyl chloride
ppg	Pound per gallon
SCVF	Surface casing vent flow
SFZ	Shale fragmented zone
σ_3	Minimum in-situ stress

Glossary

Term	Description
Abandoning	To cease efforts to produce fluids from a well and to plug the well without adversely affecting the environment
Annulus	The gap between tubing and casing or between two casing strings or between the casing and the wellbore. The annulus between the tubing and casing is the primary path for producing gas from CSG wells.
Bore	A narrow, artificially constructed hole or cavity used to intercept, collect or store water from an aquifer, or to passively observe or collect groundwater information. Also known as a borehole, drill holes or piezometer. This report uses the term 'bore' in reference to the extraction, exploration or monitoring or water.
Borehole	A hole drilled for purposes other than production of oil, gas or water (e.g. a mineral exploration borehole).
Borehole breakouts	Enlargements and elongation of a borehole in a preferential direction and formed by spalling of fragments of the wellbore in a direction parallel to the minimum horizontal stress.
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 that facilitates insertion of the casing into the well.
Cement bond	The adherence of casing to cement and cement to formation. When casing is run in a well, it is set, or bonded, to the formation by means of cement.
Cement sheath	Cement ring in the annulus between casing and wellbore or between two casing strings.
Coal seam gas	A form of natural gas (generally 95 to 97% pure methane, CH_4) typically extracted from permeable coal seams at depths of 300 to 1000 m. Also called coal seam methane (CSM) or coalbed methane (CBM).
Compaction	The physical process by which sediments are consolidated, resulting in the reduction of pore space as grains are packed closer together
Decommissioning	The process to remove a well from service
Filter cake	A deposit of fine particles left on the rock surface as a fluid leaks off. The buildup of the filter cake reduces further loss of fluid.
Formation pore pressure	The pressure in the porous rock around the well.
Gas kick	Flow of formation gas into the wellbore during drilling operations.
Fracture gradient	The pressure required to induce fractures in rock at a given depth
Hydraulic fracturing	Also known as 'fracking', 'fraccing', 'fracture simulation' or 'fluid-driven fractures', is the process by which hydrocarbon (oil and gas) bearing geological formations are 'stimulated' to enhance the flow of hydrocarbons and other fluids towards the well. The process involves the injection of fluids, gas, proppant and other additives under high pressure into a geological formation to create a fracture connecting the well to the reservoir. The fracture acts as a high conductivity channel through which the gas, and any associated water, can flow.
Hydrostatic pressure	The theoretical pore pressure that would be expected purely from the weight of water in a column running from the depth of interest to the surface.
In situ stress	The stress acting in the rock. Contrasts in the magnitude of the minimum principal stress strongly affect hydraulic fracture growth.

Term	Description
In-gauge hole	A borehole that is essentially the same diameter as the drill bit used to drill it. The borehole is under-gauge or over-gauge when the borehole diameter is smaller or larger than the drill bit respectively.
Leak-off	The process that results in loss of fluid during a hydraulic fracture treatment by diffusion from the fracture into the surrounding rock.
Leak-off test (LOT)	A test performed during drilling to measure the pressure at which a hydraulic fracture will initiate from the wellbore.
Liner	Steel pipe used to line a well and support the rock. Liners are essentially the same as casing, but do not extend to the surface.
Lost circulation	The reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string
Openhole	An un-cased section of the well.
Overbalanced drilling	Overbalanced drilling is a procedure where the pressure in the wellbore is kept higher than the formation fluid pressure
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.
Overburden formations	Named rock layers in the overburden.
Overpressure	The pressure of the fluid inside pore space is greater than the hydrostatic pressure at the same depth.
Pack off	Plugging of the wellbore annulus around a drilling string by drill cuttings and/or cavings due to wellbore wall collapse.
PKN	The 2D fracture model (Perkins-Kern-Nordgren) with the fracture length being much greater than the fracture height.
Production interval	The section of rock from which hydrocarbons are being produced.
Spacer	A spacer is a viscous fluid used to aid removal of drilling fluids before a primary cementing operation. By coating the wellbore with a reactive spacer that reacts with cement, a small filter cake is formed that prevents cement from invading the formation. A non-reactive spacer should then be run between the reactive spacer and cement slurry to prevent premature setting of the slurry.
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 CSG wells.
Underbalanced drilling	A procedure used to drill CSG wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled
Washout	An enlarged region of a wellbore. A number of factors can cause this, such as excessive bit jet velocity, soft or unconsolidated formations, in-situ rock stresses.
Well	As used in this report: a completed structure, following drilling of a wellbore, used for production of oil or gas and typically including casing, cement, and tubing strings.
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/well and geological formations, between geological formations, or to the surface.
Well breach	Failure in cement, casing, downhole and surface sealing components
Well deviation	The angle at which a wellbore diverges from vertical.

Term	Description
Well failure (1)	All well barriers failing in sequence and a leakage pathway being created across all the well barriers (King and King 2013).
Well failure (2)	Well failure or loss of well integrity may result from a well breach (or number of well breaches). Well failure can take the form of a hydrological (fluid movement between different geological units) or environmental (fluid leaks from the well at surface or contamination of water resources) breach.
Well logging	The process of recording a signal from a geophysical tool run into a well.
Wellbore	The hole initially produced by drilling and intended to be cased and cemented to create a well for 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.

Symbols

Symbol	Short description, units
A	Cross-section flow area [m^2]
d	Diameter of conduit [m]
D	Hydraulic diameter of conduit [m]
C	Hazen-Williams coefficient
f_D	Darcy friction factor
G	Acceleration of gravity [m^{-2}]
H	Hydraulic head [m]
h_f	Head loss due to friction [m]
k	Permeability [m^2]
K	Hydraulic conductivity [$m.d^{-1}$]
K_e	Effective hydraulic conductivity [$m.d^{-1}$]
K_v	Vertical hydraulic conductivity [$m.d^{-1}$]
L	Length of flow path [m]
N	Manning's roughness factor [$s.m^{-1/3}$]
P	Pressure [Pa]
Q	Volumetric fluid flux [$m^3.d^{-1}$]
U	Flow velocity [$m.d^{-1}$]
V	Kinematic viscosity [$m^2.s^{-1}$]
R_D	Reynolds number
R	Hydraulic radius [m]
r	Conduit radius [m]
S	Head loss per length of conduit [-]
μ	Dynamic viscosity [Pa.s]

1 Introduction

Subsurface resources such as minerals, water and hydrocarbons (from coal, oil and gas) are routinely exploited within Australia for industrial or agricultural uses. In such cases the resources are defined and/or obtained via the exploration and/or construction of bore holes and wells within the subsurface rock strata. In many cases these activities intersect various rock assemblages of different composition or quality. Such rock assemblages can contain other desirable resources such as groundwater, which present additional challenges to safe abstraction of mineral and hydrocarbon resources. There is the risk that poorly designed and/or constructed wells and other open boreholes connect up different aquifers to each other or the surface and potentially cause leaks to the environment (Darrah et al. 2014).To ensure efficient and environmentally sustainable utilisation of either groundwater or coal seam gas resources, bore holes or wells which penetrate multiple rock strata must be constructed to a high standard (National Water Commission 2012; DNRM 2013a; NSW 2012). Such standards ensure best practice while minimising the risk of bore integrity issues (DEHP 2014), including where the design and/or construction of the well is inadequate to prevent the movement of gasses or liquids between two or more separate hydrostratigraphic units.

Previous work undertaken for the Office of Water Science (OWS) and the Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development (IESC) (Commonwealth of Australia 2014a) included a broad background review of bore integrity issues in onshore sedimentary basins. This work identified the main causes of compromised bore integrity including:

- poor design and/or construction methods;
- poor monitoring or maintenance;
- failed integrity of bore materials; and
- poor bore decommissioning.

A strong association was also made between age and compromised bore integrity in the above work. Additional work undertaken by the OWS (Commonwealth of Australia 2013) focused on preliminary analysis of existing data on bore and well types, ages and distribution in the Surat Basin, Queensland. An outcome of this preliminary analysis was identification of the need to better understand the potential consequences of cumulative bore integrity failure on groundwater conditions within sedimentary basins. The study aims to address this knowledge gap.

Manifold (2010) defined *bore integrity* as:

"…instantaneous state of a well, irrespective of the purpose, value or age, which ensure the veracity and reliability of the barriers necessary to safely contain and control the flow of all fluids within or connected to the well"

A further set of useful definitions was given by King and King (2013) and subsequently adopted by Davies et al. (2014); they defined well barrier failure and well integrity failure as follows:

- *well barrier failure* was used to 'refer to the failure of individual or multiple well barriers (e.g. production tubing, casing, cement) that has not resulted in a detectable leak into the surrounding environment'.
- *well integrity failure* was used for 'cases where all well barriers fail, establishing a pathway that enables leakage into the surrounding environment (e.g. groundwater, surface water, underground rock layers, soil, atmosphere)'

In order to address the knowledge gap on the potential consequences of bore or well failure, bore or well failure (or loss of well integrity) is specifically defined in this report as (see Figure 1.1 for the barriers and potential breach locations):

failure to safely contain and control the flow of all fluids within or connected to a well. It can be caused by any of various forms of 'well breach' (including failure of cement sheaths/plugs/bonds, casing, and downhole and surface sealing components) and may result in hydrological breach (fluid movement between geological formations – including formations not targeted for exploitation) and environmental breach (contamination of or water balance impact to water resources).

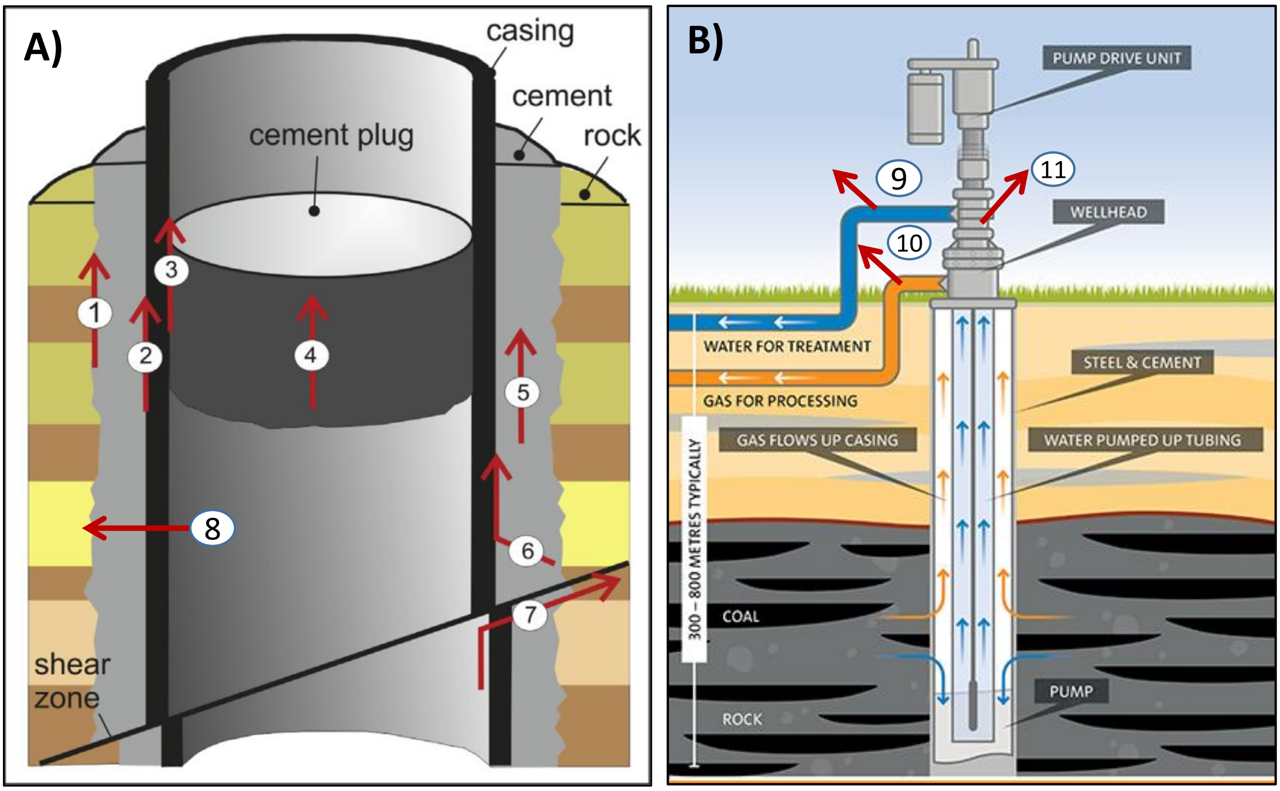

Figure 1.1 A) Examples of well barrier failure (well breach) that provide pathways for fluid movement (hydrological breach): 1 – between cement and surrounding rock formations, 2 – between casing and surrounding cement, 3 – between cement plug and casing or production tubing, 4 – through cement plug, 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 wellbore and 8 – across corroded casing and degraded cement sheath (modified from Davis et al. 2014). B) Examples of environmental breach: 9 – produced water release from water pipe line, 10 – gas release from gas pipe line and 11 – reservoir fluids release from wellhead (modified from QGC 2016).

Well, hydrological and environmental breaches are closely linked to each other where well breach may cause hydrological breach and possibly environmental breach. If the hydrologic breach results in significant changes in an aquifer's baseline hydrochemistry and/or changes to an aquifer's water balance, an environmental breach has occurred.

As a consequence, if the mechanisms responsible for well breach are eliminated or properly managed, the hydrological and environmental breaches would not occur. The entire life span of a well may be divided into three broad phases: design and/or construction, production and abandonment. Table 1.1 summarises well and hydrological breaches and their potential environmental impacts in each phase. These will be discussed in detail throughout the remainder of the report.

In this report the terms "well", "bore", and "wellbore" are used interchangeably; most often "well" is used when referring to the extraction of oil, conventional gas and coal seam gas, "bore" when referring to the extraction, exploration or monitoring of water and the exploratory sampling of coal where a bore is required, and "wellbore" for the hole initially produced by drilling, with the final intended purpose being for production of oil or gas.

Table 1.1 Summary of well and hydrological breaches and their potential environment impacts (see main text for references).

Well Breach (mechanisms)		Hydrological Breach (fluid flow pathways)	Environmental Breach (impacts)
Design/Construction	Insufficient drilling fluid pressure in openhole	Uncontrolled reservoir formation fluid influx into the well with potential consequence of blowout; Wellbore instability or breakouts or washouts	Reservoir fluid could be released to the atmosphere from the well or to aquifer through the well
	Excessively high drilling fluid pressure in openhole	Formations fractured unintentionally	The release of drilling fluid into aquifer
	Cement sheath and bond failure	Fluid pathways created in cement sheath, along cement interfaces with casing or rock formation	Contamination of aquifer by the fluid from high pressure geological unit or reservoir
	Cement slurry loss	Cement slurry pathways created or via existing fractures	Potential invasion of cement slurry and/or other wellbore fluids into aquifer
	Insufficient cement height	Well annulus left open, casing exposed to corrosion	Contamination of aquifer by fluids from high- pressure geological unit or reservoir
	Inappropriate location of fluid entry points (openings) to the well, or lack of bore casing or annulus seal.	Fluid pathways created via well openings, uncased wellbore sections or annulus.	Contamination of aquifer by fracturing fluid or reservoir fluids
	Hydraulic fracturing	Fluid pathways created along wellbore or hydraulic fractures creating connection with aquifer	Contamination of aquifer by fracturing fluid or reservoir fluids
Production	Deformations in overburden due to reservoir compaction	Well shear failure connecting reservoir with aquifer	Contamination of aquifer by reservoir fluids
	Corroded steel casings and tubings	Fluid pathways created in casing and tubings	Contamination of aquifer by fluids from reservoir
	Gas migration due to reservoir depressurisation	Water bores and mineral exploration bores, compromised/uncemented oil & gas and CSG wells, natural and/or induced fractures	Contamination of aquifer and atmosphere
Abandonment	Cement sheath and bond failure	Fluid pathways created in cement sheath, along cement interfaces	Contamination of low-pressure aquifer by fluids from high-pressure geological units
	Poor quality or degraded cement sheath	Mud channels in cement sheath, incompletely cemented annulus, highly degraded and porous cement matrix	Contamination of low-pressure aquifer by fluids from high-pressure geological units
	Degraded cement plugs	Highly degraded and porous cement matrix	Contamination of low-pressure aquifer by fluids from high-pressure geological units or fluids from reservoir or high pressure geological unit released to the atmosphere
	Corroded steel casings	Fluid flow pathways created across the steel casing	Contamination of low pressure aquifer by fluids from high pressure geological units

2 Well failure mechanisms

This section discusses well failure mechanisms that are considered relevant to CSG producing environments. The wells reviewed include onshore conventional oil and gas wells, coal seam gas wells, coal exploration bores and water bores. Well failure mechanisms are discussed in each phase of the well life span.

2.1 Failure mechanisms as a consequence of well design and/or construction

CSG wells are required by the CSG industry and are critical to the processes of exploring for, testing and producing CSG (Moore 2012). Some of the CSG wells may operate for many years or even for several decades. Constructing a CSG well may include operations such as drilling, running and cementing casing and stimulation (e.g., hydraulic fracturing). Well failure or loss of well integrity could occur during or as a consequence of each of these operations.

2.1.1 CSG well drilling

Drilling is the first step in constructing a CSG well, and this step contains 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, wellhead and cap rock formation (NORSOK 2004).

Drilling fluid density or mud weight plays a vital role in maintaining borehole stability prior to a casing being cemented. Figure 2.1 shows a schematic of the stable and safe mud weight windows during the drilling stage of the well. The stable mud weight window (green line) is bounded, on the left, by the breakout mud weight (m_w) below which borehole failure takes place and, on the right, by the minimum in-situ stress (σ_3) above which seepage loss of drilling fluid could occur in the formation containing pre-existing closed natural fractures. The safe mud weight window (yellow line) is bounded, on the left, by the formation pore pressure (P_{pore}) below which formation fluid influxes into the borehole and, on the right, by the formation breakdown pressure ($P_{breakdown}$) above which the intact formation is hydraulically fractured resulting in drilling fluid losses into the rock formations.

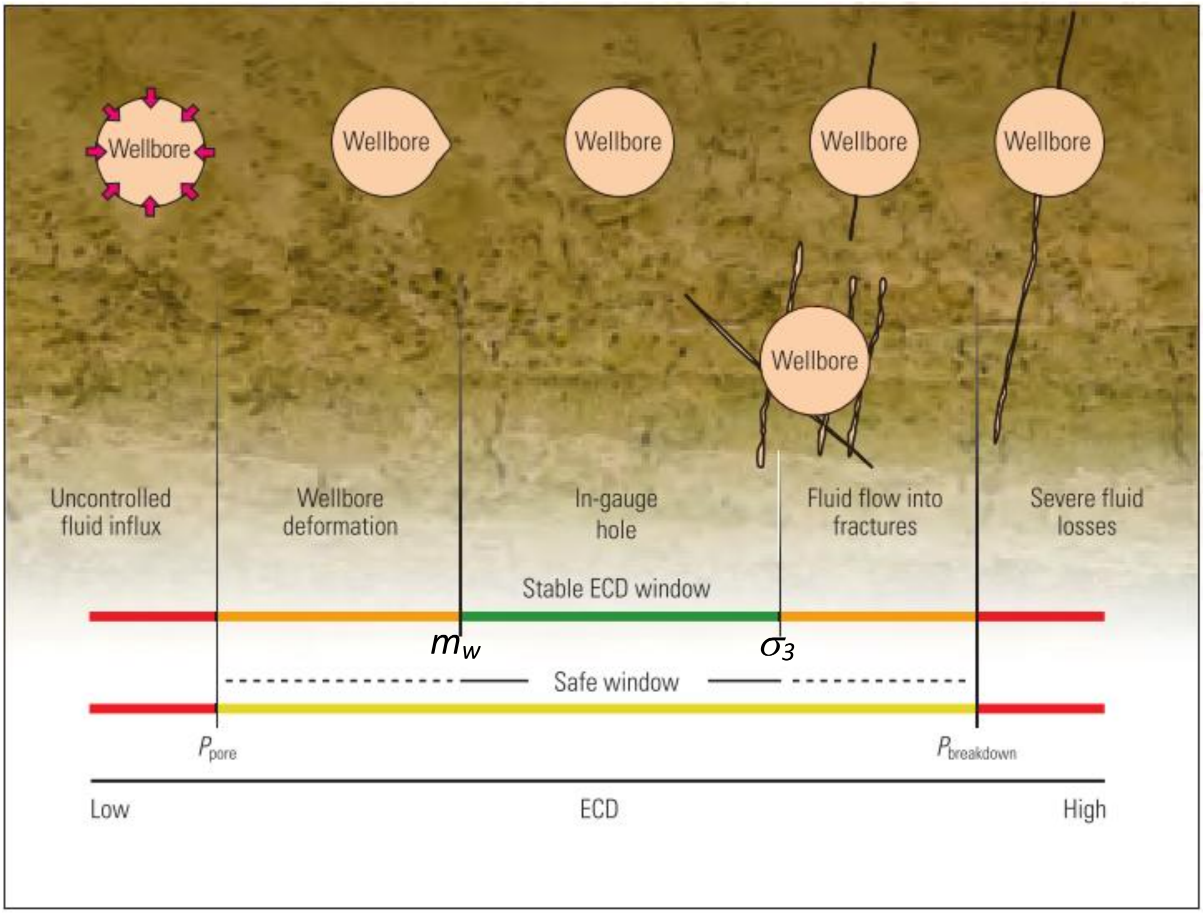

Figure 2.1. A schematic of safe and stable mud weight windows (from Cook et al. 2012, Copyright Schlumberger, with permission).

2.1.1.1 Stable Mud Weight Window

Before a drill bit penetrates a rock formation, the rock at depth is in a state of mechanical, thermal and chemical equilibrium. A borehole is drilled by cutting and removing the rock inside the hole and replacing it with a column of drilling fluid. Due to the differences in mechanical (physical) properties, temperature and chemistry between the drilling fluid and the formation rock, drilling a borehole disturbs the state of equilibrium in the rock formations. Consequently, rock failure, which potentially compromises well integrity, becomes possible.

Minor instability, such as a small amount of rock breaking off the wellbore wall and falling into the well, is rarely a problem to drilling and can be tolerated in subsequent openhole logging or cementing operations. Major instability is caused by excessive rock failure such that the total volume of cuttings and failed rock materials (both amount and size of cavings) in the hole cannot be circulated out by the drilling fluid (Zoback 2007; Zoback et al. 1985). The wellbore size can be enlarged significantly during drilling. This can result in poor displacement of mud during cementing and a poor quality cement sheath behind the steel casing (Cook and Edwards 2009). Figure 2.2 shows an example of wellbore instability issues in a shale formation where the wellbore size was enlarged from 215.9mm (8.5 inches) – i.e. the size of the drill bit – to 635mm (25 inches) as measured on caliper logs (Van Oort 2003).

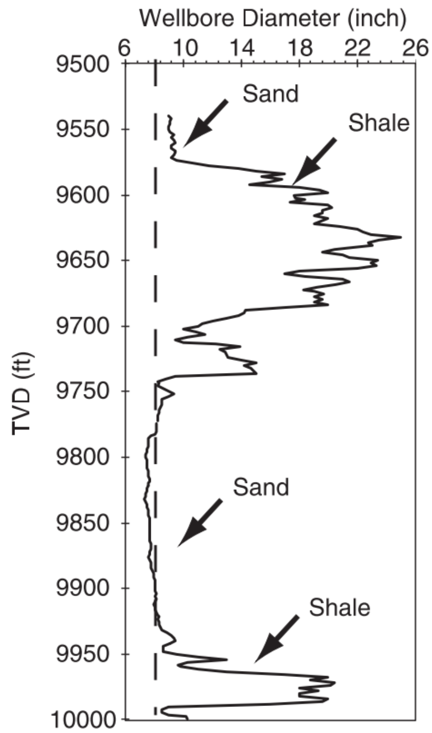

Figure 2.2 Example of wellbore instability and washout in shale formation (Van Oort 2003).

2.1.1.2 Safe Mud Weight Window

As shown in Figure 2.1, the lower bound of the safe mud weight window is the formation/reservoir pore pressure in conventional overbalanced drilling. For coal seams, the reservoir pore pressure has been reported to vary from near normal water pressure gradient (Cunnington and Hedger 2010; Johnson et al. 2010; Meng et al. 2011) to highly over pressurised (Decker and Horner 1987; Kaiser and Ayers 1994; Logan 1993). For example, in the Fruitland Formation of the San Juan Basin, USA, the pore pressure gradient ranges from 6.8 kPa/m to 9.5 kPa/m (0.30 to 0.40 psi/ft) (underpressurised) in the south to 9.95 kPa/m to 14.2 kPa/m (0.44 to 0.63 psi/ft) (overpressurised) in the north central part of the basin. When the drilling fluid pressure inside the borehole is less than the formation pore pressure, formation fluid influx into the borehole takes place. Uncontrolled formation fluid influx compromises well integrity.

The upper bound of the safe mud weight window is the formation breakdown pressure (or fracture gradient) that is determined from the in-situ stresses, formation properties and well trajectory. When the drilling fluid pressure is greater than the fracture gradient, uncontrolled massive drilling fluid losses into the formation can take place, resulting in significant well integrity issues from the openhole.

To reduce risks of compromised well integrity during drilling, several tests have been designed, including leak-off-tests (LOT). Leak-off tests have traditionally been used to measure the formation fracture gradient. In the early stage of a field development, LOT tests are routinely conducted prior to drilling a new hole section. After cementing the casing, approximately three metres (or ten feet) of fresh formation is drilled below the casing shoe. Pressure is applied to the casing and into the freshly drilled openhole at a slow and constant pump rate while the well is shut in to measure the response of the formation. Initially, the pressure builds up linearly as the drilling fluid is pumped. As pumping continues, the pressure in the wellbore continues to build up until a fracture is induced in the wellbore wall. Once a fracture is created, the slope of the pressure versus time (or volume) curve decreases in response to the increased volume and system compliance associated with the fracture. The point at which the slope changes is traditionally known as the leak off point (LOP) and is taken to represent the fracture gradient. The standard LOT is typically stopped shortly after the LOP is passed. The elevated mud pressure during the LOT is not only applied to the fresh formation drilled below the casing shoe, but to the entire well. This may impact on the cement sheath and cement bonds behind the newly cemented casing.

One challenge with respect to drilling coal seam gas wells in Queensland is encountering loss zones during drilling and cementing operations (Tan et al. 2012). In one well, minor to moderate dynamic losses were encountered while drilling the high angle (70^o – 85^o) 215.9mm (8.5 inches) production hole section using a 1.05SG (8.8 pounds per gallon) water based mud system. As soon as a drilling fluid loss is detected, a lost circulation material (LCM) is added to the drilling fluid. LCM is cellulose material and prevents fluid loss by blocking the pores and fractures in the formation rock with cellulose particles.

In cases where drilling fluid loss is too severe and the LCM does not work, the hole is completely sealed with a cement plug, before being re-drilled.

The standard drilling fluid currently used in the CSG industry in Australia is water-based, whereas oil-based and synthetic-based fluids are not permitted due to environmental concerns (NSW Code of Practice 2012: QLD Department of Environment and Heritage Protection 2013). The drilling fluid is generally a mixture of water, clays, fluid loss control additives, density control additives, and viscosifiers. Potassium chloride is often used as a weighting agent and to help control swelling clays. Organic polymers or clay may be added to the base fluid to raise the viscosity and aid in removal of drill cuttings.

2.1.2 Running casing and cementing

Once a CSG well is drilled to the designed depth, a steel casing string is run into the borehole and cemented into the ground (Figure 2.3). Poor cementing, leaking through casing connections, and cement sheath degradation and casing corrosion are some of the risks that could compromise well integrity. This section discusses some of the well failure mechanisms associated with running casing and cementing the annulus.

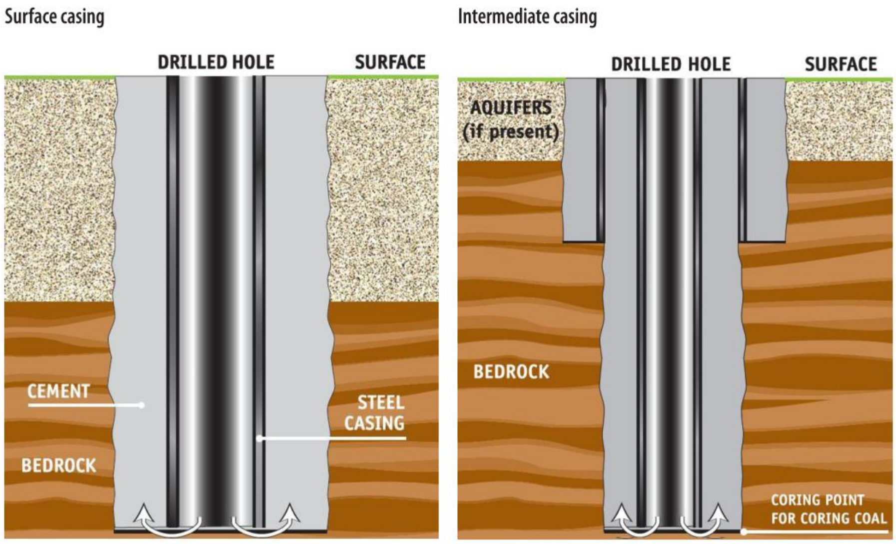

Figure 2.3. Cement pumped down the hole and forced up the annulus between the rock (gravel etc.) and casing – indicative diagram only (APPEA, 2012).

2.1.2.1 Challenges in cementing CSG wells

As shown in Figure 2.3, cement fills and seals the annulus between the casing strings or between the casing string and the formation. In general, cement has three basic functions (Taoutaou 2010):

- To provide zonal isolation and segregation;
- To protect casing from corrosion by formation fluids; and
- To support casing and formation.

Cementing CSG wells is largely comparable to cementing conventional oil and gas wells. Cement sheaths of a minimum thickness of 16 mm and 13 mm surrounding the surface and production casings respectively over the total cementing depth are mandatorily required in Qld and NSW (Department of Natural Resources and Mines, Queensland 2013a; Department of Trade & Investment, Regional Infrastructures & Services, Resources & Energy, New South Wales 2012). Furthermore, the code of practice requires that good oil field practice be applied in cementing CSG wells. This includes optimum slurry flow rates, conditioning of the hole prior to pumping cement slurry and application of casing centralizers. Furthermore, while the CSG well may be drilled underbalanced, the cementing operation must be slightly overbalanced to prevent free gas migration in the cement column after placement is accomplished (Halliburton 2007). Underbalanced drilling refers to a procedure to drill CSG wells where the drilling fluid pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. In contrast, overbalanced drilling is a procedure where the pressure in the wellbore is kept higher than the formation fluid pressure.

The coal seams are naturally fractured with cleats. The unique challenges presented when cementing CSG wells include cement slurry invasion into coal seams, low fracture gradients and annulus pack off (Mohammad and Shaikh 2010). Several seams of coal could exist along a CSG well. The challenges exacerbate when the wells are deviated or approach horizontal or have a low temperature at the bottom resulting in a longer cement setting time.

It has been reported that many loss zones are encountered during drilling and cementing operations of some CSG wells in Queensland (Tan et al. 2012). Cement slurry losses into coal seams are undesirable. In addition to plugging the coal cleats, which causes a reduction of well productivity, cement slurry losses can result in a reduced cement sheath height. This leaves part of the well annulus uncemented. Unprotected casing is prone to corrosion (Huff and Merritt 2003) resulting in formation fluid leaking into the well or the fluids in the well leaking to the formation. Furthermore, the uncemented annulus could hydraulically connect two or more different aquifers, resulting in hydrological breach between different geological units. To reduce or eliminate cement slurry losses, a number of methods have been developed, including use of low density cement, foam cement, adding lost circulation materials to the cement slurries, and utilisation of reactive spacer as preflush ahead of the cement slurry (Tan et al. 2012).

2.1.2.2 Factors affecting cement sheath and cement bond integrity

Wellbore condition

Successful zonal isolation is not only dependent upon selecting the right cement slurry, but also involves preparation of the wellbore for cementing. A good cementable wellbore is a pre-requisite for a successful cementing job. The ideal cementable wellbore and its requirements are shown in Figure 2.4 (Smith 1990).

Ideally, the wellbore to be cemented should be in-gauge or nearly in-gauge with a smooth well surface. The wellbore-formation flow should be static with no formation fluid influx or lost circulation. The casing should be centralised in the openhole section with a sufficiently wide annulus, and the mud in the hole should be properly conditioned and free of cavings from sloughing shales. Breakouts or washouts are to be avoided or minimised by use of proper mud weight and chemistry during drilling.

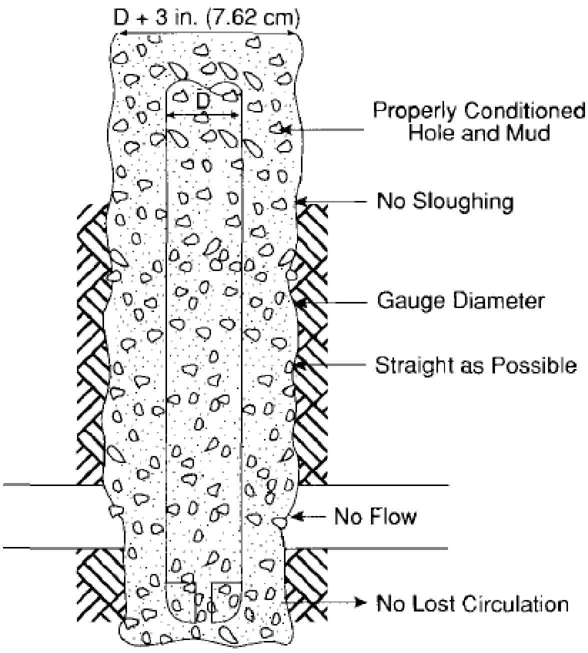

Figure 2.4. Ideal cementable wellbore requirements (after Smith 1990).

It should be noted that not all rock failure on the well surface will present as breakouts or washouts. Under certain conditions, some of the rocks that have failed due to mechanical stress concentration may still attach to the wellbore wall and the induced fractures can extend deep into the formation (Figure 2.5). This type of rock failure, detectable from image logs and sonic logs but not necessarily from caliper logs, should also be avoided or minimised by using a drilling fluid with sufficient mud weight and proper chemistry, since the mechanical damage is unlikely to be sealed completely with cement. This leaves a damaged zone behind the cement sheath with a significantly enhanced permeability which could form a potential pathway for fluid migration along the cement-rock interface. Such a damaged zone due to drilling and cementing was also identified as a potential pathway along the wellbore by Armstrong et al. (2009).

A shale fragmented zone (SFZ) along the interface between cement and shale was observed from the core recovered from a 55-year old well with 30 years of CO_2 exposure (Carey et al. 2007). The core was cut in the caprock about 4m above top of the reservoir. The SFZ is characterised by black fragments of shale (which have split along bedding planes) embedded in a gray carbonate-rich fine-grained matrix. The matrix is composed of drilling residue mixed with cement. An important feature of the SFZ is presence of regions of open porosity. This SFZ may have prevented the cement from forming a tight seal with the shale wall. Whether the cement-rock interface with such a SFZ will lead to the breach of the seal between different aquifers will depend on the extent of the SFZ along the wellbore, which is governed by the local geological and geomechanical conditions specific to the well.

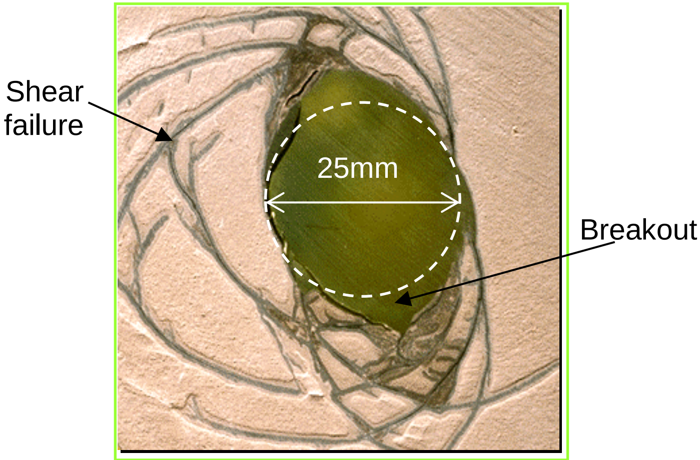

Figure 2.5. Photo of a cross-section of a failed model borehole in shale tested at CSIRO illustrating that mechanical damage due to shear failure can develop beyond borehole breakout or washout zones. The diameters of the borehole and shale sample were 25 mm and 80 mm respectively. The failure was induced by applying an external boundary stress to the cylindrical shale sample. These fractures can significantly enhance permeability in comparison with intact shale (CSIRO un-published experimental study).

Mud conditioning and displacement

Effective hole cleaning, mud displacement and mud filter cake removal is a primary requisite to prevent gas or fluids migrating inside a cement sheath or along the interface between cement and formation. The main objective is to provide a relatively clean casing pipe, annulus and well surface to which the cement sheath can bond (Watson et al. 2002). Some of the good industry practices to achieve this includes conditioning the drilling fluid, using spacers and flushes ahead of cement slurry, rotating or reciprocating casing, centralizing the casing and maximizing the displacement rate (Crook et al. 2001).

If channels of mud remain in the annulus, they may provide a preferential migration pathway inside the cement sheath (Bonett and Pafitis 1996). Furthermore, in permeable formations a mud filter cake is likely to develop on the well surface as a result of overbalanced drilling. If the filter cake is not removed from the well surface prior to cementing, it could dehydrate after the cement sets, resulting in an annulus at the formation and cement interface. Incomplete mud removal often occurs in deviated wells (Keller et al. 1987), where a continuous mud channel may remain along the narrow section of the cemented annulus. Figure 2.6 shows a photo of drilling mud channels in the cemented annulus due to incomplete displacement of the drilling mud with the inner casing off centre (Watson 2004), and Figure 2.7 is a photo of cement sheath core containing shale fragments recovered from an old well due to poor hole cleaning (Duguid et. al. 2013).

Figure 2.6. Incomplete displacement of drilling mud and the resulting drilling mud channels. Over time, the gels in the drilling mud will shrink, forming fluid migration pathway in the annulus (after Watson 2004).

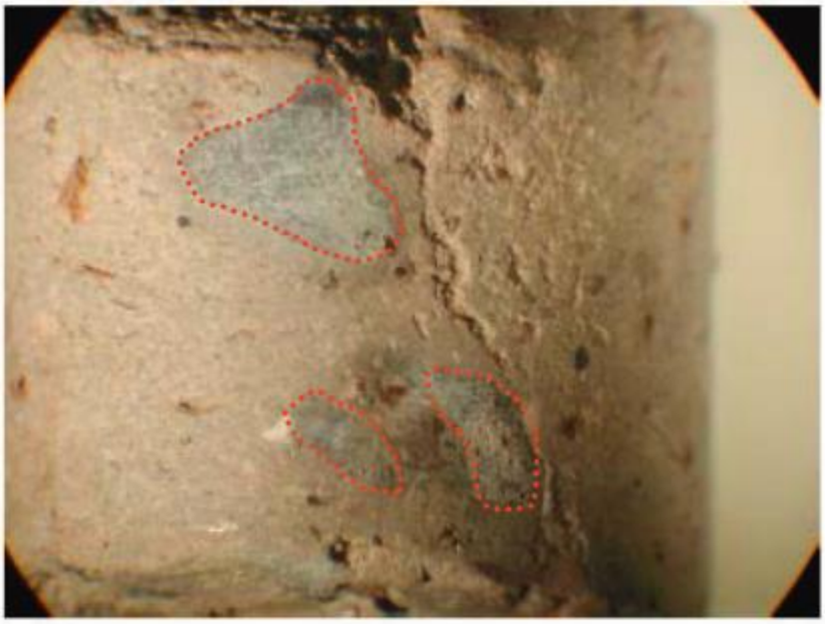

Figure 2.7. Photo of a sidewall cement core containing shale fragments in the cement sheath, indicating poor hole cleaning prior to cementing the casing (after Duguid et al. 2013).

Cement sheath and bond failure

After setting (i.e. formation of hardened cement), the cement sheath becomes a solid of very low permeability (i.e. microdarcies) and hydraulic conductivity (i.e. on the order of 10^{-6} m/d) (Parcevaux et al. 1990) and bonds to the casing and formation surfaces. As a result, fluids can no longer migrate within or through the sheath. However, downhole pressure and temperature can change due to various operations in the well's history, such as LOT/FIT (formation integrity) tests and casing pressure tests, well production and shut-in, and reservoir hydraulic fracturing stimulation. These changes in well pressure and temperature can induce radial deformation of the casing and failure in cement sheath, resulting in de-bonding on the interfaces between cement sheath and casing/formation, creating radial fractures (Figure 2.8) and microannuli and migration pathways (Goodwin and Crook 1992; Watson et al. 2002).

The impact of the cement sheath and bond failure on well integrity will depend on the extent of such failure along the wellbore and specific geological conditions. For example, one study in the Gulf of Mexico (King and King 2013) found that there was no breach in isolation between geological units with pressure differentials as high as 97 MPa (14,000psi), as long as there was at least 15 m (50 feet) of high quality cement seal between the geological units.

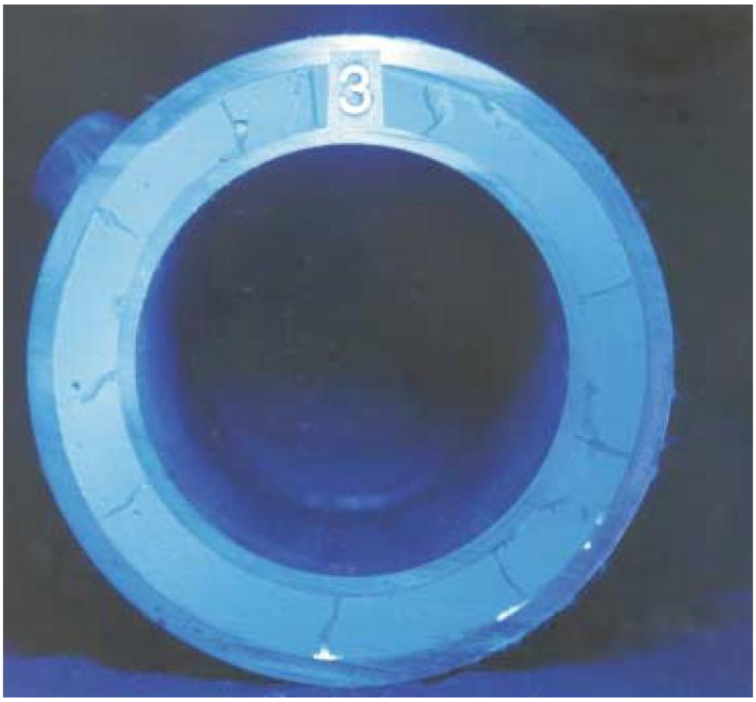

Figure 2.8. Cement sheath failure, resulting in cracks developing from pressure cycling on the internal casing (Watson et al. 2002).

Tubing/Casing corrosion

Corrosion attacks every metal component, including casing and tubing, at all stages in the life of an oil and gas well (Brondel et al. 1994). Corrosion induced casing and tubing damage and loss of well integrity have been widely reported (e.g. Bazzari 1989; Vignes and Aadnoy 2010; Watson and Bachu 2009). Corrosion encountered in petroleum production involves several mechanisms. These can be grouped into electrochemical corrosion, chemical corrosion and mechanical and mechanical/corrosive effects. A detailed description of these mechanisms can be found in Brondel et al. (1994). Corrosion rates depend on the type of steel used, i.e. with higher rates for mild carbon steel (on the order of 0.1-1 micro metre/year in favourable conditions such as high pH[1] (Kreis, 1991) up to 1 mm/ year in case of chloride induced localised corrosion (Elsener 2005)) compared to stainless steel or steel coated with corrosion resistant material (fractions of micro metre/year).

Both the inside and outside of the casing can be damaged by corrosion. The corrosion on the outside of the casing can be caused by corrosive fluids (typically saline water) or formations in contact with the casing or by stray electric current flowing out of the casing into the surrounding fluids or formations. Severe corrosion may also be caused by sulfate-reducing bacteria. Corrosion damage on the inside of the casing is usually caused by corrosive fluids produced from the well, but the damage can be increased by high fluid velocities (Lyons and Plisga 2004).

The cement quality, and cement sheath and bonding integrity play a critical role in protecting the casing from external corrosion. Cement provides favorable geochemical conditions (i.e., high pH between 12-13) which retard corrosion due to passivation of the steel. When the pH drops below approximately 9-10, passivation is lost and corrosion may commence. Cement degradation and failure in cement sheath and de-bonding of the interfaces along the casing and rock formation due to changes in wellbore stress and temperature as discussed earlier will expose the casing to corrosive fluids and casing

[1] In new concrete with a pH of 12-13, approximately 7,000 – 8,000 ppm of chlorides are required to start corrosion of embedded steel. If the pH drops to a range of 10-11, the chloride threshold for corrosion is considerably lower, at 100 ppm (PCA 2002)

corrosion can start. Well integrity could be lost when the wellbore fluid migrates along degraded cement sheath or debonded interfaces that hydraulically connect with an aquifer or the surface.

Furthermore, the study by Bazzari (1989) on casing leaks discovered that the type of cement used is also important to casing corrosion. Severe corrosion occurred in wells for which construction and permeable light cement were used, instead of the usual Portland class G cement with additives. Leakage rates were higher in shallow zones where high sulfate concentrations caused the construction cement—which was nonsulfate resistant—to break down owing to formation of deleterious expansive mineral products such as ettringite[2] (a sulfate aluminium hydrate: calcium monosulphoaluminate), exposing the exterior of the casing to corrosive aquifer water.

2.1.3 Hydraulic fracturing

2.1.3.1 What is hydraulic fracturing

Hydraulic fracturing is the process of injecting fluid under high pressure into a reservoir to create new fractures or widen existing ones to increase CSG well productivity for low permeability coal. In Australia, a small proportion of CSG wells needs to be stimulated by hydraulic fracturing. For example, approximately 30% of the Australia Pacific LNG Project's wells are expected to be completed by hydraulic fracture stimulation over the life of the Project (APLNG 2015). The fracturing fluid is pumped into the production casing, out through casing perforations and into the target reservoirs at a pressure high enough to cause the reservoir formation to fracture or "breakdown" (the pressure required to breakdown the formation is termed breakdown pressure). As the high pressure pumping is continued, fractures (new or existing) can continue to grow or propagate.

The rate at which the fracturing fluid is pumped must be fast enough such that the pressure necessary to propagate the fracture is maintained (the pressure to propagate the fractures is termed propagation pressure). As the fractures continue to propagate, a proppant, such as sand, is added to the fracturing fluid. When the pumping is stopped, and the excess pressure in the fractures is removed, the proppant will keep the fractures open, allowing reservoir fluids to flow more readily through this high conductivity channel into the well during production.

The injection stage of a hydraulic fracturing operation takes from tens of minutes to a few hours (Taleghani 2009). A production well stimulated with hydraulic fracturing is likely to be subjected to cyclic pressures throughout the life of the well. Hydraulic fracturing is often performed sequentially at multiple depths, or stages, in a well corresponding with the location of the coal seams. Hydraulic fracturing is also sometimes repeated during the life of the well to boost declining gas productivity.

The pressure imposed on the production well during hydraulic fracturing is likely to be the highest for the entire well life. The propagation pressure must be higher than the minimum principal in-situ stress by a certain amount to keep the fracture propagating. The breakdown pressure is usually higher than the fracture propagation pressure to overcome near wellbore restrictions, such as stress concentration and damage, and non-alignment of perforation with the preferred fracture direction (i.e. the maximum horizontal stress direction in a normal fault stress regime).

2.1.3.2 Hydraulic fracturing induced fluid migration pathways

Fluids can migrate via pathways within or external to the production well, which can be created due to the cyclic pressures exerted to the well during hydraulic fracturing operations. While production wells are designed and constructed to isolate fluids in different geological units, inadequate design and/or construction or degradation of the casing or cement can allow fluid movement that can cause breach of inter-aquifer seals. The US EPA (2015a) identified the following four mechanisms or pathways through which hydraulic fracturing could cause or increase the chances of impacting the surrounding subsurface formations due to contamination:

- Well failure may provide pathways for groundwater pollution by allowing contaminants to flow into overlying aquifers through either casing failure or incorrect isolation of target coal seams
- Fracturing fluid leak-off, which is the migration of injected fracturing fluid from the created fractures to other areas within the coal seam or adjacent geologic formations
- Gas leakage through the unintentional migration of methane gas along the well and creating connectivity with adjacent aquifers
- Increased mobility and migration of naturally occurring substances from the coal seam into adjacent aquifers.

[2] Sulfates from gypsum or other sources used to control properties of cement are readily soluble and react soon after cement comes into contact with mix water. However, if extremely high levels of sulfate are added, abnormal expansions can occur from excessive calcium sulfoaluminate formation after hardening and continuing until the sulfate source becomes depleted (PCA 2001).

The following discussions focus only on fluid migration pathways along the production wells induced by hydraulic fracturing operations. The fluid migration via induced fractures within subsurface formations away from the well will not be discussed as it is outside the scope of this review.

Casing failure induced by hydraulic fracturing

High pressures associated with hydraulic fracturing operations can damage the casing and lead to breach of the inter-aquifer seal. The casing string 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. To withstand the stresses created by the high pressure of hydraulic fracturing, the well and its components must have adequate strength and elasticity. If the casing is not strong enough to withstand these stresses, a casing failure may result. If undetected or not repaired, casing failures will serve as pathways for fracturing fluids to leak out of the casing.

Casing failure resulting in both burst and collapse has been observed during hydraulic fracturing operations or shortly following the operation. In a recent case study on the blowout from the Frankchuk 44-20 SWH well in Dunn County, North Dakota (US EPA 2015b), it was reported that the production, surface, and conductor casing of the well ruptured due to overpressurisation during a multi-stage hydraulic fracturing, causing fluids to spill to the surface and to travel through the ruptured casings into shallow aquifer. This blowout led to the installation of monitoring wells on and around the well pad and monitoring of nearby domestic wells, water supply wells and municipal wells. Two potential pathways for contamination were identified in the study, direct release for hydraulic fracturing fluids from the ruptured well into the aquifer and indirect contamination from surface infiltration of the released fluid down into the aquifer.

A casing collapse was experienced when a rapid depressurisation of a wellbore occurred while completing a CSG well in Scotia field, Queensland (Johnson et al. 2002). This was immediately following a hydraulic fracturing operation to stimulate the coal seams. The field is known to have a highly deviatoric in-situ stress field, i. e., the difference is large between the maximum and minimum principal in-situ stress magnitudes. It was observed the BHTP (bottom hole treating pressure) was high, indicating the fractures created in the coal seam was complex. It was believed that during the treatment, any shear and conjugate shear sets of fractures within the coal seams were dilated and propped open by the treatment inducing quite large deformation in the coal. The rapid reduction in wellbore pressure resulted in parting of the casing and downhole assembly.

Cement and cement bond failure induced by hydraulic fracturing

Radial fractures in cement sheath and de-bonding on the interfaces between the casing and cement and between cement and formation due to cyclic stresses have been discussed in Section 2.1.2.2. The process of fracture propagation along the interfaces driven by fluid injection at high pressure is briefly discussed below.

While a small area of de-bonding may not lead to fluid migration, the microannuli in the cement sheath due to de-bonding can serve as initiation points for fracture propagation along the interfaces. Behrmann and Nolte (1998) noted that a microannulus is usually present after perforating and/or immediately after hydraulic fracturing pumping begins. Maintaining a good bond during the breakdown phase of hydraulic fracturing can be problematic because of a hydraulically propagated microannulus that is analogous to hydraulic fracturing. The propagation is explained as follows: as the wellbore is pressured, the fluid in the microannulus is also pressured, increasing the width of the microannulus and allowing more fluid to enter. The microannulus will propagate when the fluid pressure exceeds the microannulus closure pressure. The microannulus initially extends in a radial geometry from the perforation tunnels. After some period, the individual radial patterns coalesce into one microannulus around the complete circumference of the cement sheath. At this stage, the annulus is analogous to a confined height PKN (Perkins-Kern-Nordgren) fracture with its height equal to the circumference of the wellbore, and can begin to extend up and/or down along the wellbore until breakdown of the reservoir formation by hydraulic fracturing. At the breakdown point, the fracturing fluid pressure is the highest for the entire hydraulic fracturing process. A detailed experimental and theoretical modelling study on the cement interface debonding can be found in Lecampion et al. (2010). The microannulus formed in this way can be a conduit for gas migration, in particular because the lighter density of gas provides a larger driving force for migration through the microannuli than for heavier liquids (Dusseault et al. 2000).

CO_2 migration to surface along a microannulus in a CO_2 injection well was recognised as a plausible cause to observed leakage from a CO_2 injector (Loizzo et al. 2011). The European projects RECOPOL and MovECBM studied the injection of CO_2 in a coal seam at the Kaniow site, Poland to help release absorbed methane in the coal and capture the CO_2 within the coal structure. The injection happened at depths of around 1000m through a 7 inch casing in a purpose-drilled new well. Due to low permeability of the coal, continuous injection was only possible after a hydraulic fracturing stimulation. Upon completion of the injection, the soil gas surveys at the injection site showed anomalies in CO_2 and He concentrations and CO_2 fluxes. Cement evaluation logs indicated the presence of a fluid-filled microannulus behind the 7 inch casing between the perforation interval and the previous casing shoe. The CO_2 leaked along the microannulus to the previous casing shoe and then to the surrounding shallow aquifers, which caused the soil gas survey anomalies.

Goodwin and Crook (1992) found a sudden increase in sustained casing pressure (SCP: pressure in the casing at the surface) in wells that were exposed to high temperature and pressures. Subsequent logging of these wells showed that the high temperature and pressures led to shearing of the cement/casing interface and a total loss of the cement bond. Syed and Culter (2010) and others (Muehlenbachs et al. 2012; Rowe and Muehlenbachs 1999) noted that increased well pressures and cyclic stresses may also lead to increased occurrence of sustained casing pressure in wells where hydraulic fracturing was performed. Although wells can be tested at the surface for well barrier failure and well integrity failure by determining if there is pressure in the casing, it does not identify which barrier has failed (Watson and Bachu 2009).

2.2 Failure mechanisms during or as a consequence of production

CSG production in Australia requires initial pumping and removing of water to sufficiently reduce the hydrostatic pressure (depressurisation) in CSG reservoirs so that methane can be desorbed from the coal. CSG is produced at a well pressure that is close to atmospheric pressure (Ely et al. 1990; Schraufnagel 1993). The ratio of water pumped to methane produced is initially high and declines with increasing CSG production (Figure 2.9).

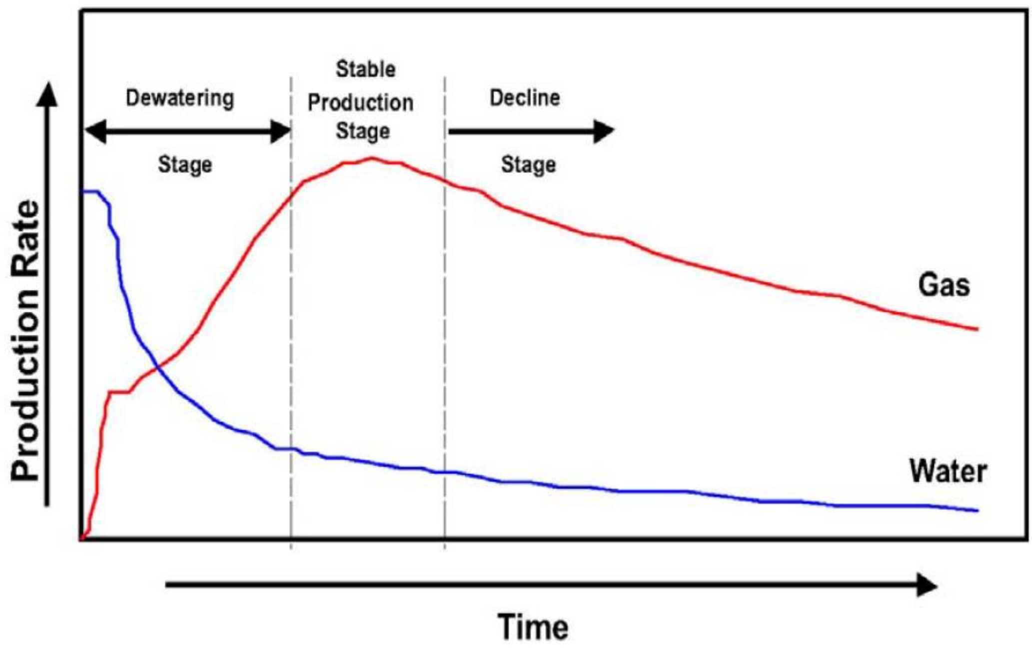

Figure 2.9. Water and gas production over time (from US EPA 2004).

2.2.1 Well failure mechanisms associated with depressurisation in reservoir

The depressurisation process reduces the pressure in the coal seams and surrounding formations that hydraulically connect with the coal seams. This creates a highly depleted pressure zone around the CSG well. For highly permeable coal seams the reservoir pressure within such a zone during production is expected to be similar to the bottomhole pressure, which is close to the atmospheric pressure. Typical depths of CSG reservoirs in Australia range from 300 m to 1000 m and the pre-production reservoir pressure is expected to be in the range of approximately 3 MPa to 10 MPa assuming a normal water pressure gradient. In comparison, atmospheric pressure at sea level is typically about 0.1 MPa. Coal seam compaction due to depressurisation is expected for highly fractured and compressible coal seams. For example, in a recent background review on subsidence from coal seam gas extraction in Australia (Commonwealth of Australia 2014b), a predicted cumulative compaction of up 0.28 metre from all hydrostratigraphic units was reported for the Surat and Bowen basins. The prediction assumed cumulative compaction of all strata subject to drawdown, with deformation considered unlikely to be expressed at the surface; strong strata in the overlying sequences can bridge the settlement effects in the coal seam and buffer propagation of the settlement to the surface (Commonwealth of Australia 2014b).

In addition to the mechanical compaction induced due to depressurisation, the coal matrix also shrinks as methane gas is produced (by desorption) and removed from the coal. This shrinkage reaches its maximum towards the end of production. The magnitude of shrinkage is highly variable but can reach in excess of one percent vertically (Coffey 2014). The total compaction experienced by the coal seam is the sum of the coal shrinkage due to gas desorption and the mechanical compaction due to depressurisation.

Surface subsidence is a primary indicator of compaction at depth and its predicted magnitude is typically required as part of CSG environmental assessments. Monitoring is also required to verify the predictions, by identifying the actual magnitude and extent of subsidence. The predicted cumulative compaction (rather than surface subsidence) varies significantly for different CSG fields in Australia, ranging from “a few millimetres” and “negligible” for the Camden Gas fields by AGL to 280 mm for the Roma gas field by Santos (Commonwealth of Australia 2014b). This variation is not surprising since the amount of subsidence will depend largely on the depth and thickness of the compacting geological units, including coal seams and other units affected by depressurisation, the properties of the overburden and magnitude of depressurisation. All the studies reviewed by the Commonwealth of Australia (2014b) assumed a linear elastic theory to calculate settlement using simplified compaction formulae. It is not clear if coal shrinkage and other time dependent deformation mechanisms, such as creep, are included in the subsidence prediction.

The impact of compaction at depth on CSG well integrity has not received the amount of attention provided to predicting and monitoring land surface subsidence. The compaction of coal seams and other units would impact on the integrity of the cement sheath and cement bonds for CSG wells, since the casing and cement materials have very different mechanical properties from the compacting coal seams and other surrounding geological units affected by depressurisation.

Well failure induced by reservoir compaction due to oil and gas production is a significant problem for conventional oil and gas wells. The mechanisms for well deformation and failure due to compaction are expected to be similar to a certain degree for conventional and CSG wells. This is because the casing and cementing materials used for constructing the CSG and conventional wells are essentially the same; and the manner of compaction affecting the CSG and conventional wells is similar (i.e., differential deformations are developed on the interfaces due to the different deformation properties of casing, cement and rock/coal, regardless of whether compaction is experienced by CSG wells or conventional wells). These differential deformations can induce shear failure on the interfaces, hence de-bonding. The severity of the impact is, however, likely to be much less for CSG wells than for conventional oil and gas wells because depressurisation magnitude is likely to be much less for CSG wells (in general, the reservoir pressure is higher in conventional oil and gas reservoirs than in coal seams because of the much greater depths of the former hydrocarbon reservoirs). Furthermore, the geological and geomechanical environments for CSG and conventional wells can be significantly different, hence, not all the mechanisms experienced by the conventional oil and gas wells will be significant to CSG wells and the risks should be evaluated on a case by case basis.

There is currently a knowledge gap on if/how compaction at depth impacts on CSG well integrity as evidenced by the lack of literature reporting depressurisation induced well integrity issues for CSG wells. As such, a brief review on the well failure mechanisms for conventional wells due to reservoir compaction is presented below, to shed some lights on potential impacts of depressurisation on CSG well integrity.

The mechanisms of reservoir compaction and surface subsidence-induced well failures have been a subject of intensive study for a number of years (e.g. Bruno, 1992, 2001 and Dusseault et al. 2001). Significant reservoir compaction can induce compression and buckling type well damage within the producing well interval. Slip on bedding planes and faults within the reservoir and overburden may also occur, causing severe shear damage to the wells. There are three critical forms of well damage that have been observed in almost all structural settings (Bruno 2001; Dusseault et al. 2001)

- Casing damage by shear in the overburden;
- Casing damage by shear at the top of a production interval
- Casing buckling and shear within the producing interval.

These are briefly described below.

Casing damage by shear in the overburden

Reservoir compaction induced shearing can cause casing damage in overburden formations above the reservoir (Bruno 2001); the larger the reservoir compaction, the greater the casing impairment potential in the overburden (Dusseault et al. 2001).

Figure 2.10 illustrates the geomechanical reactions to reservoir compaction in the overburden. The crestal section experiences an increase whilst the remote flanks experience a drop in the minimum horizontal stress, and the rocks above the shoulders experience an increase the shear stress. If the shear stress in the overburden exceeds the strength of the bedding planes or the weak lithology interfaces, low angle slip occurs. If there is a potential for reactivation of low angle thrust faults in the crest region, a thrusting mechanism can develop as the horizontal stress increases, leading to the thrust fault stress regime. Furthermore, there is the potential for a high-angle normal fault mechanism to develop on the flanks, leading to the normal fault stress regime.

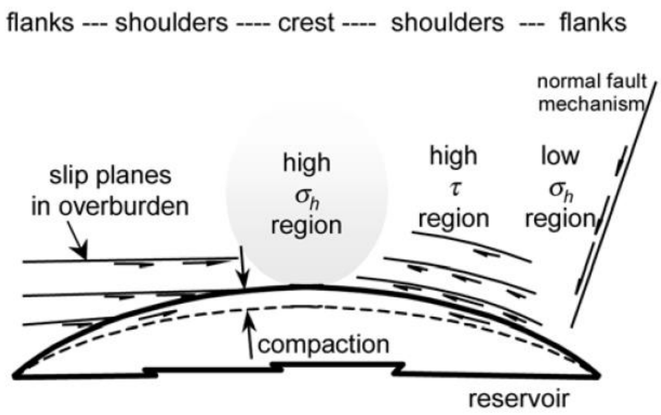

Figure 2.10 Compacting reservoir and slips on bedding plane and faults in overburden (after Dussealt et al. 2001).

It appears that localised shear deformations in weak formation layers within the overburden have occurred in almost every field that has been investigated worldwide (Bruno, 1990; Fredrich et al. 1996, 2001; Poland and Davis 1969; Vudovich et al. 1988). The shear deformations of the casing damage tend to be localised over a relatively short length of casing, in the order of only several feet, and are often related to weak formation layers rather than to highly induced shear stress (Bruno 2001; Dusseault et al. 2001). Figure 2.11 shows a sample casing deformation pattern noted in caliper logs from a damaged gas well (9.625" casing) in Southeast Asia (Bruno 2001). The localised shear damage in at weak overburden layers can be widely distributed over all portions of the field subject to significant compaction (Dale 1996; Fredrich et al. 1996; Hilbert et al. 1996; Bruno 2001).

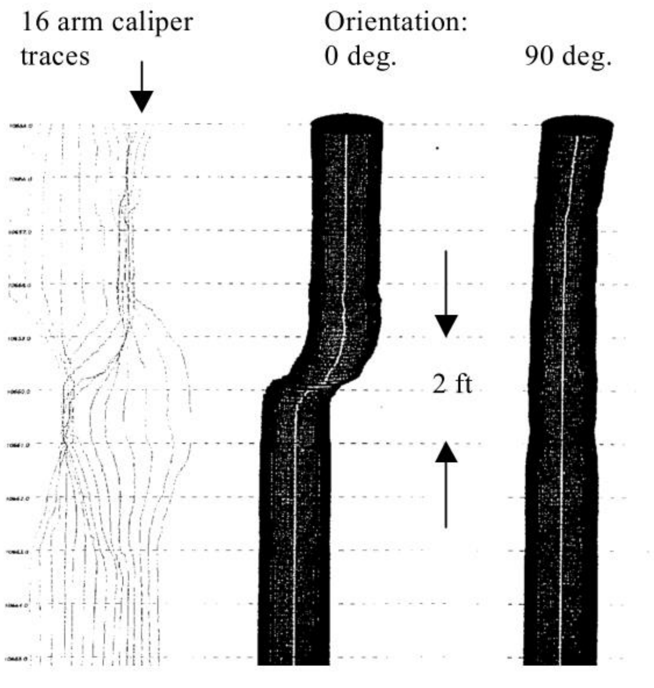

Figure 2.11. Sample casing deformation pattern noted in calliper logs for damaged gas well in Southeast Asia (after Bruno 2001).

Casing damage by shear at top of the production interval

The second critical casing damage mechanism noted in many fields is localised shear damage near the top of the producing interval (Bruno 2001). This type of damage appears to be the result of a combination of vertical movement of the underlying compacting reservoir and differential lateral contraction and interface slip of the producing reservoir relative to the capping shale. The producing reservoir formations are typically more permeable and soft than the capping shales. The contrast in pressure change and stiffness leads to differential lateral contraction and interface slip between the capping shale and reservoir. This form of damage is most dominant for relatively shallow reservoirs because the overburden load at the top of the producing interval, which provides the normal force resisting shear deformation, is of lower magnitude than for very deep reservoirs. For deviated wells, shear damage at the top of the producing interval can be exacerbated by vertical compaction of the producing formation, which can add additional local casing compression or bending (Yadav et al. 2003).

Casing buckling and shear within the production interval

The third critical casing damage mechanism is axial compression and buckling within the producing interval (Bruno 2001). This may be caused by vertical deformation. A typical cement and casing completion is illustrated in Figure 2.12. As the reservoir formation compacts as a result of pore pressure reduction, loads are transferred from the formation rock to the cement and finally to the casing. The well casing may fail due to compressive yielding or buckling. The cement sheath may also be damaged from high shear and compressive stresses.

The most likely location for casing compression failure is near the centre of the reservoir where the vertical compaction strain is largest. If no slip occurs between the formation and the cement sheath and between the cement sheath and casing, the compacting reservoir pulls the cemented casing along with it, and may cause compression failure of the casing. If slip occurs on the interfaces, the sealing capacity of the interfaces may be lost.

Casing instability or buckling may occur if the axial load becomes large and the reservoir formation provides insufficient lateral restraint. The formation lateral restraint could be lost or reduced if a large vertical section of the casing is very poorly cemented, or cavities surrounding the well developed due to sand/solid production.

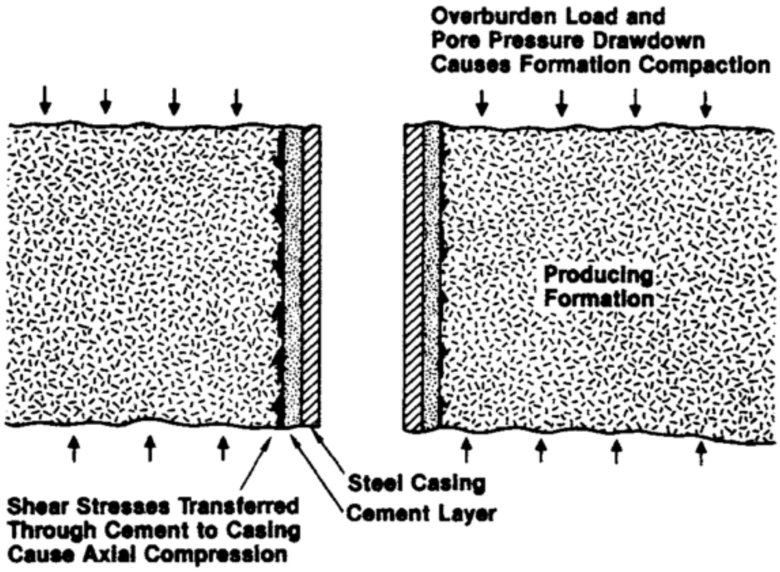

Figure 2.12 Typical well completion subject to formation compaction (after Bruno 1992).

It should be noted that the discussions on casing failure above due to reservoir compaction are in the context of well failure for conventional oil and gas wells. Well failure or loss of casing function is defined as when the casing pressure integrity is impaired, or the distortion of the wellbore becomes so large that tools cannot be lowered down the hole, or the production tubing is impaired. The pressure integrity loss arises through two mechanisms. The casing collar threads become sufficiently distorted so that the seal is lost (thread popping), or a physical rupture of the casing develops (cracking or ripping). It is expected that cement sheath failure and interfaces de-bonding would have occurred prior to the well or casing failure.

Because depressurisation in CSG reservoirs is in general much less than in conventional oil and gas reservoirs, the severity of reservoir compaction on well integrity is expected to be much less for CSG wells than for conventional wells. Furthermore, the maximum impact due to compaction is expected towards the end of the CSG reservoir life, as this is the point at which the reservoir pressure is likely to be lowest and coal shrinkage reaches its maximum. However, the consequences of compaction-induced well failure may differ for CSG wells compared to those of conventional wells due to shallower depths of the potentially compacted formations and their proximity to water supply aquifers.

2.2.2 Gas migration

Gas in coal

In undisturbed coal seams, the vast majority of methane is stored as an adsorbed layer on the internal surfaces of the micropores in the coal matrix. The micropores of coal have immense capacity for methane storage. At pressures below 1000 psi (or 6.9 MPa), coal can store far more gas in adsorbed state than conventional reservoirs can by compression. The gas storage capacity for a given coal is governed by pressure and temperature. Figure 2.13 illustrates a typical Langmuir isotherm for coal, which relates the gas storage capacity of the coal to pressure, and which depends on the coal rank, and reservoir temperature. The isotherm can be used to predict the critical desorption pressure and the volume of gas that will be released from the coal as the reservoir pressure is lowered.

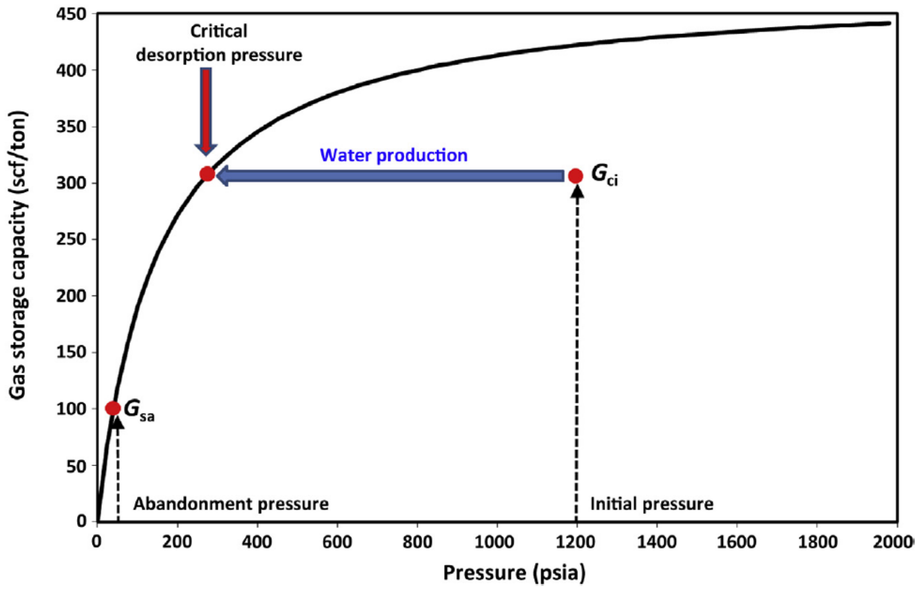

Figure 2.13 A typical Langmuir isotherm for coal (Aminian and Rodvelt 2014).

Gas desorption

As shown in Figure 2.13, the groundwater in the coal seams must be pumped from a well to decrease the water pressure in the surrounding coal. As the water pressure is decreased below the critical desorption pressure, methane desorbs. The methane first dissolves in water. Because methane solubility in water is limited (about 25 mg/l under atmospheric pressure), the recovery efficiency of the dissolved methane is not very high (Armstrong et al. 2009). Efficiency is increased when the water pressure in the coal is decreased sufficiently for methane to exist largely as a free gas phase and to migrate to the production well. This migration involves the movement of both water and gas from the micropores in the coal matrix and coal cleats. These phase transitions occur because the pressure decreases from the coal seams to the pumping well.

Gas transport

The main transport mechanism for dissolved methane in groundwater is by advection. Advection is the movement of methane with the bulk fluid phase. Where methane is present in its dissolved form, it will be carried by the water that it is dissolved in. Water will flow from zones of high to low hydraulic head (hydraulic head as a metric of potential energy per unit weight). The amount of water that a porous medium, such as coal and rock, can conduct is a product of the pressure gradient and the hydraulic conductivity of the porous medium. As the water pressure is decreased and/or temperature is increased, some of the dissolved gas will liberate from the water and becomes free gas.

The main difference between the movement of dissolved gases in water and free gases is buoyancy. Free gases tend to move from high potential energy to low potential energy when a continuous gas phase is present, otherwise gases may rise upwards depending on the relative strength of the capillarity forces versus the buoyancy forces in water. The greatest volume of flow of gas and water will occur along the pressure gradient through the pathway with the highest conductivity and cross sectional area. Hence the majority of the free gas and dissolved gas in the zone affected by water pumping and depressurisation will move towards the production well. However, at some distance from the edge of the depressurised zone, where the effects of depressurisation are less, the force of buoyancy of the free gas will overcome that of the pressure gradient, and the free gases will tend to move away from the production well in the updip direction. These gases might eventually make their way to shallower intervals and potentially discharge to the surface, either through wellbores or via natural geological pathways as surface seeps. Gas may also accumulate in overlying aquifers where there is an established pathway between the coal seams and the overlying aquifer.

Any assessment of environmental impacts (e.g. increased levels of methane gas) associated with well integrity failure should include understanding the baseline conditions. Indeed, methane gas is naturally present in both shallow and deep groundwater and may be transported as a dissolved gas or as a free gas. Depressurisation of coal seams is the primary gas release mechanism responsible for releasing sorbed methane into the groundwater. Depressurisation may occur as a result of both natural and anthropogenic factors. Natural mechanisms include short-term pressure changes in shallow formations due to flooding causing trapped gas to dissolve and migrate with the groundwater. An example of a long-term mechanism is climate change causing groundwater levels to drop which reduces the hydrostatic pressure in coals seams and thus reduces its capacity to retain the gas (Walker and Mallants 2014).

In addition to the above natural factors, anthropogenic factors include i) water extraction from water bores for domestic use and stock and CSG wells, ii) drilling for bore construction which will release pressure from below confining layers, iii) water migration from deeper to shallower formations through preferential pathways (abandoned coal exploration bores, conventional gas and petroleum wells, and water bores), and/or iv) natural water pressure changes following droughts (pressure decrease) and floods (pressure increase). In the case of depressurisation due to groundwater abstraction from water bores or water loss via pathways provided by abandoned bores and wells, the gas may be transported via such bores or via other pathways such as faults, fractures or more permeable zones (Walker and Mallants 2014).

Gas migration pathways

During the study on sources and migration pathways of natural gas in near surface ground water beneath the Animas River Valley, Colorado and New Mexico, Chaffin (1994) identified that among the three potential gas migration pathways (rock pore spaces, natural fractures and man-made conduits), the man-made conduits are the primary gas migration pathways. This includes poorly designed, constructed and damaged, and inappropriately abandoned petroleum wells, and water bores and mineral boreholes. A conceptual diagram of gas migration and migration pathways for an Australian CSG field is presented in Figure 2.14.

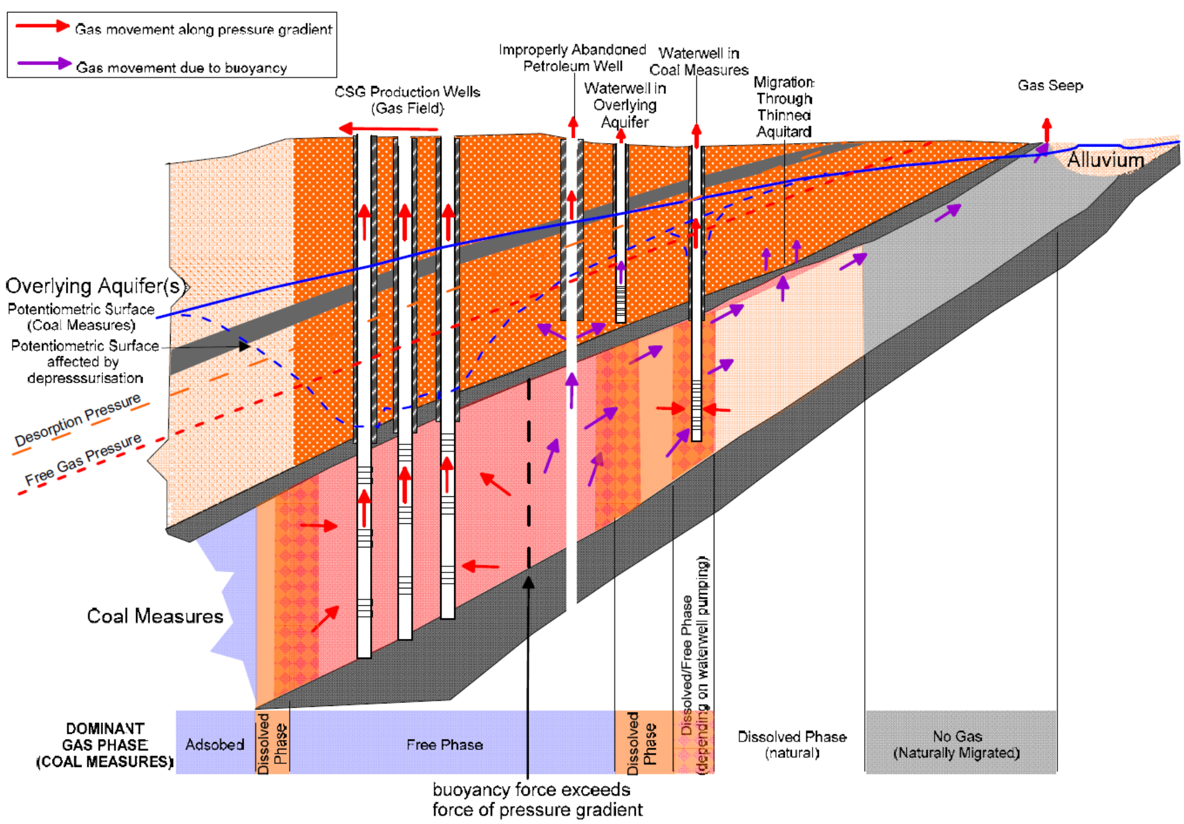

Figure 2.14. Conceptual diagram of gas migration in the Surat Basin near Roma due to pressure gradient and buoyancy, and migration pathways (from APLNG 2010).

Figure 2.15 shows the locations of groundwater bores in relation to CSG wells for the CSG field northeast of Roma, Queensland. As an example, it illustrates the scale of potential gas and water migration pathways due to existing non-CSG wells in CSG fields. Whether such non-CSG wells will indeed become pathways for gas and water migration due to CSG production will depend on the stratigraphic levels these wells were completed in and on local geological conditions. For the example shown in Figure 2.15, the number of known groundwater bores screened in the Walloon Coal Measures is small (i.e. 27), and often at safe distance from CSG wells. An assessment of the potential risks of such pathways is beyond the scope of the current report.

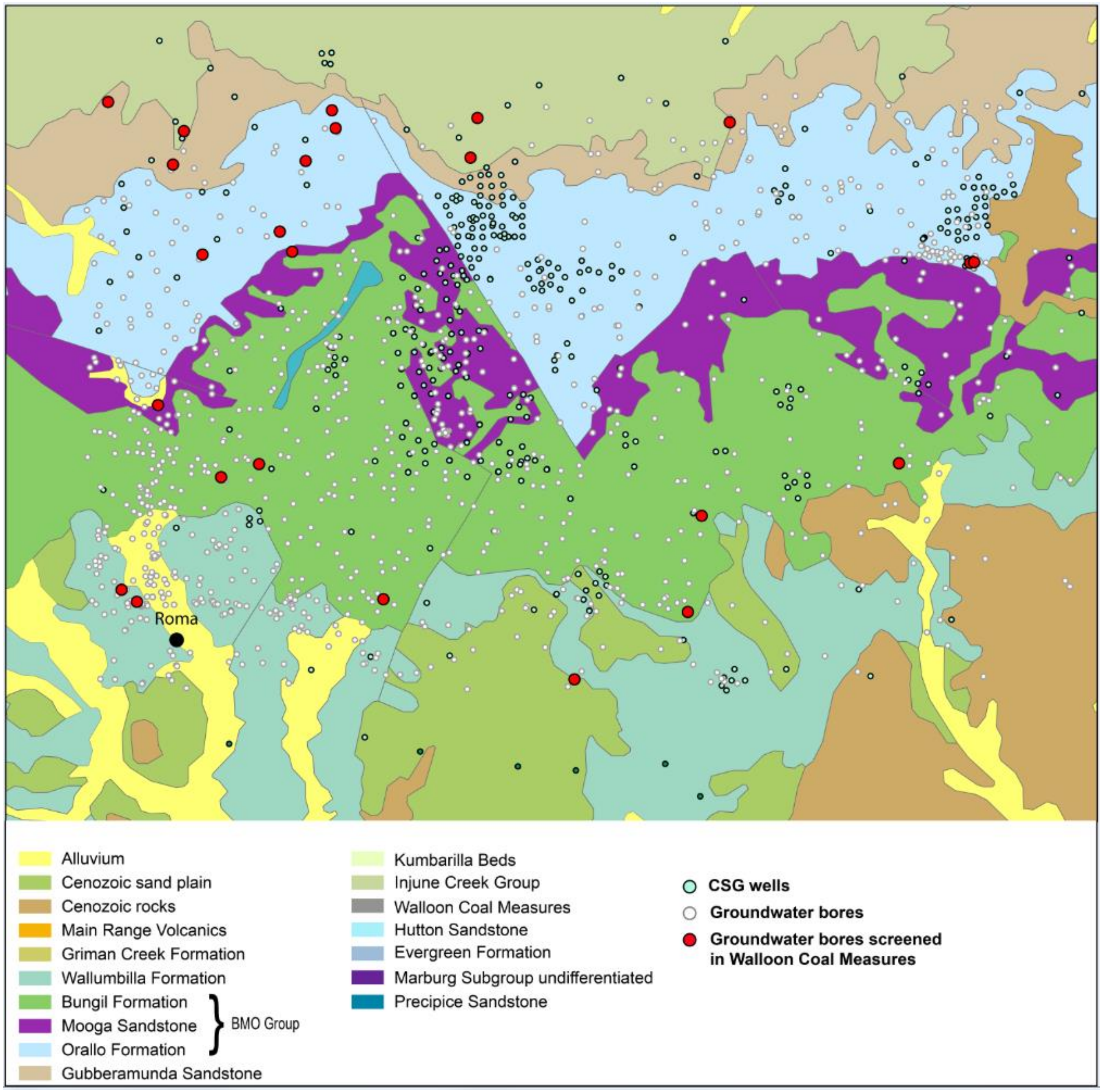

Figure 2.15. Locations of CSG wells (blue dots), groundwater bores not screened in the Walloon Coal Measures (white dots) and water bores screened in the Walloon Coal Measures (red dots) in a CSG field, North East Roma, Queensland. The width of the image is approximately 86 KM. Data obtained from Queensland Government database (http://qldspatial.information.qld.gov.au/catalogue/custom/search.page?q=%22Coal%20seam%20gas%20well%20locations%20-%20Queensland%22). Accessed in August 2015.

Gas blowouts in Surat and Bowen basins, Queensland

A comprehensive review on gas occurrences prior to CSG development in Surat and Bowen basins was documented in a CSIRO report to the Department of Natural Resources and Mines, Queensland (Walker and Mallants 2014). As with all coal seam gas basins, methane gas has always been present in both shallow and deeper geological units in the Surat and Bowen basins (DNRM 2013b). The presence of methane gas has become more apparent as exploration for water, oil and gas has occurred. Construction of wells and bores has potentially provided conduits for methane gas migration. Some examples of the spectacular gas blowouts in the early 20th century reported by media (Walker and Mallants 2014) are quoted below.

"At Roma in 1900, natural gas blew into a water bore at 1123 metres", reported by Courier Mail (Brisbane) May 26, 2001.

"AT FIRST there was just a rumble – more of a burp, really – from deep beneath a little rise somewhat extravagantly known as Hospital Hill. Then, at 1.15pm on October 16, 1900, the wellhead exploded, sending water and mud about 15m into the air above the small collection of stores and shacks known as Roma". Reported by Courier Mail (Brisbane) May 26, 2001.

"When the man in charge of the shift noticed that the water was gradually rising over the casing. Then he noticed that the water had become less in volume and was impregnated with air or gas...when suddenly the beam bearing the weight shot up , and an immense volume of gas rushed from the mouth of the casing with a terrific roar...Perhaps for a quarter of an hour it continued thus, when suddenly , with an explosion similar to the discharge of a canon, the gas was converted to flames... the flame shot up to a height of 40 feet or more and none could nearer to it than 50 yards, so intense was the heat...The flames consumed everything , and including the engines...It was remarkable that the immense flames were for a long time unaccompanied by smoke, but in a few hours, the flames were discoloured by black smoke, and the fierceness with which they roared was greatly intensified. The change was attributed to the presence of petroleum in large quantities...The first and only thing to be done now is to find a method of extinguishing the fire", reported by Western Star and Roma Advertiser (Toowoomba), Wednesday 28 October 1908

"The recent blow of gas at Roma has once more awakened interest in the possibilities of obtaining petroleum in Australia. The gas was induced to flow by lowering the head of water in the bore" (with a depth of 3700 feet). The water level was lowered a few hundred feet at Roma, and the back pressure on the gas was thereby reduced to such an extent that the gas blew out" reported by The Northern Miner (Charters Towers), Saturday 13 November 1920.

"An old oil bore eight miles from Roma broke a nine-ton concrete seal this morning and hurled a column of gas and water 120 feet into the air", reported by The Central Queensland Herald (Rockhampton), Thursday 20 March 1952.

The blowout from a CSG well in the Daandine field (Surat Basin, South West Queensland) is a more recent example of gas blowout widely reported in the media and well documented by DNRM (2011). This time the blowout was from a CSG well that had been drilled (but suspended) in 2009 with well completion being undertaken in 2011. The well was capped after drilling and the blowout occurred when the well was being prepared for installation of a pump for production. After initial checks, the well was uncapped in order to install the pump. Before this could occur, water and gas began to flow to surface with increasing intensity. The blowout lasted for more than a day and spew methane and water up to 15 metres high before the well was secured by using heavy drilling mud. It appeared that the water level in the well had dropped to a point such that the pressure in the coal seam allowed the gas to desorb and flew into the well. It was reported that the owner of the well actually pumped some water into the well prior to uncapping it. It was not known if a blowout preventer was installed on the well, as this is a mandatory requirement by the Code of Practice for Constructing and Abandoning Coal Seam Gas Wells (DNRM 2013a). This scenario is similar to a gas kick in conventional oil and gas well drilling. The gas in the well would need to be circulated out of the well under a controlled way.

While gas blowouts are some of the more spectacular examples of CSG well failure, they are very rare. While there have been 6734 CSG exploration, appraisal and production wells drilled in Queensland from 2010 to March 2015, the blowout in the Daandine field is the only reported case in Queensland for the same period. In New South Wales, one blowout was recorded in 2011 (Parliament of New South Wales 2011). Finally, CSG operators are required to install blowout preventers to CSG well heads to prevent the uncontrolled release of water and gas from a well (NSW Petroleum (onshore) Act 1991; DNRM 2013a).

2.3 Pathways for failure in decommissioned and abandoned wells

2.3.1 CSG well abandonment

Whenever a CSG well is taken out of production, or a CSG appraisal well is not developed into a production well, CSG well abandonment measures are taken to ensure the environmentally sound and safe isolation of the well, protection of groundwater resources, isolation of the productive formations from other formations, and the proper removal of surface equipment. This involves sealing the hole completely from the bottom to surface using a series of cement plugs, which provide a seal preventing any cross flow of water and gases between underground layers, as well as isolating all downhole zones from the surface (APPEA 2012). The well head is then removed and the steel casing (filled with cement) is cut off at least 1.5 m below ground level, sealed with a metal identification plate and buried.

2.3.2 Potential leaking pathways

For a leak to occur in an abandoned well, whether the leak is to surface or cross flow subsurface between different geological units, three elements must exist (Watson 2004):

- There must be a source formation where gas or liquid hydrocarbons or other fluids exist in the pore space;
- There must be a driving force between the source formation and surface in case of leakage to surface, or between different geological units in case of subsurface cross flow. Such driving force could be the difference in pressure, temperature or salinity;
- There must be a leakage pathway between the source formation and surface or between different geological units.

Watson and Bachu (2009) attributed well leakage/failure to poorly cemented casing/hole annuli, casing failure and abandonment failure for abandoned wells, while Gasda et al. (2004) identified interfaces between cement and formation rock and/or casing, and casing and cement plug for abandoned wells as the preferential pathways for fluid flow. 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 (Zhang and Bachu 2011). Figure 2.16 shows a schematic of potential leakage pathways along an abandoned well.

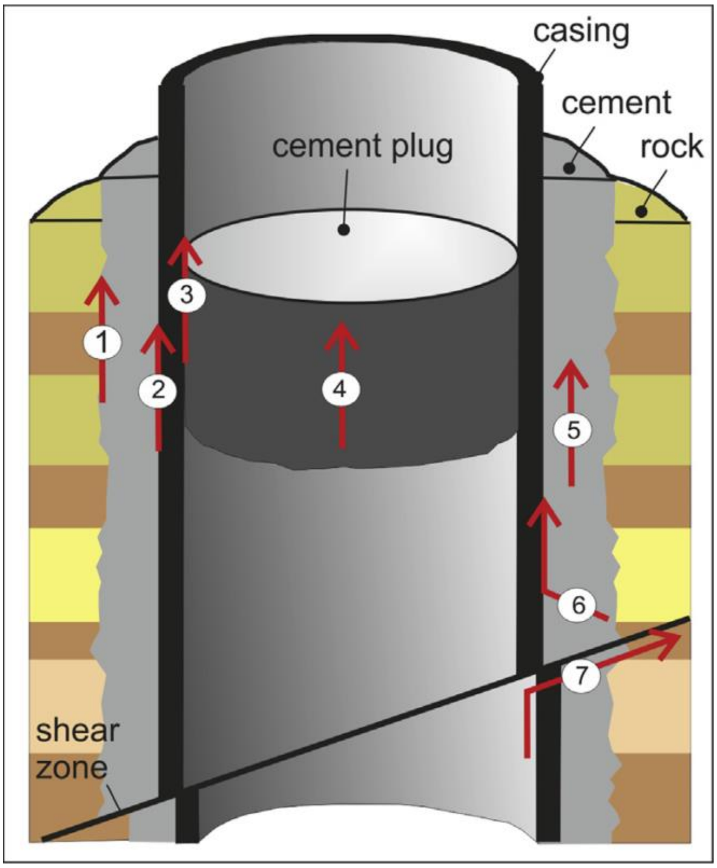

Figure 2.16 Routes for fluid leakage in a cemented wellbore. 1 – between cement and surrounding rock formations, 2 – between casing and surrounding cement, 3 – between cement plug and casing or production tubing, 4 – through cement plug, 5 – through the cement between casing and rock formation, 6 – across the cement outside the casing and then between this cement and the casing, 7 – along a shear wellbore (after Davies et al. 2014).

2.3.3 Durability of cement and cement bonds

The cement used in well construction and abandonment is designed to have a long life span (NSW Chief Scientist and Engineer report 2014). Despite considerable research on petroleum well integrity (e.g. Davies et al. 2014; Popoola et al. 2013), very little information exists about the long-term (100 -1000 years) durability of abandoned petroleum wells (NSW Chief Scientist and Engineer report 2014). Also the current review did not find any studies on the long-term (100-1000 years) durability of the cement under CSG well conditions in Australia. Other studies have been conducted investigating cement degradation under simulated CO_2 geological storage conditions (Azuma et al. 2013; Satoh et. al. 2013; Connell et al. 2015). Laboratory experimental studies have focused on the characterisation of cement and cement/rock, cement/casing interface behaviour when exposed to CO_2.

It has been observed that when pre-cured cement cores are exposed to stationary CO_2 saturated water and supercritical CO_2, cement alteration occurs. The alteration is characterised by a series of concentric fronts of carbonation and dissolution, penetrating from the fluid/cement interface into the unaltered cement core. During this penetration, initial precipitation of carbonates may plug the porosity and initially seal the cement. The rate and extent of the alteration zone is a function of the square root of time and can be interpreted as a diffusion-limited reaction (Satoh et al. 2013). However, in the NaCl solution, the cement cores developed only few alteration zones and hardly displayed time-dependency.

For the injection experiments along the interfaces between cement and casing and between cement and rock the dominant flow path was a microannulus. Upon reaction between CO_2 and cement, the flow path could be blocked by precipitating altered phases, such as carbonate and Na-K rich fine silicate residues.

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 (Yamaguchi et al. 2013). The model was validated based on the laboratory experimental results by Satoh et al. (2013) prior to applying for abandoned wells. 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 time periods. For example, the alteration length of cement seals after 1000 year exposure was approximately one metre, leading to the conclusion that cement would be able to isolate CO_2 in the reservoir over the long-term.

Popoola et al. (2013) noted that the literature on corrosion and cement degradation considers CO_2 stored at high pressure to be more aggressive than methane. Therefore, a conclusion can be drawn that if CSG wells are properly designed, installed and maintained, the risk of long-term leakage from CSG wells from both the casing and cement can be considered to be minimal, although there is scope for additional research to specifically assess the impact of abandoned CSG wells over an extended timeframe (NSW Chief Scientist and Engineer report 2014).

The study on long-term corrosion of cement by Yamaguchi et al. (2013) assumed that the abandoned wells were in a good condition and free of defects, such as microannulus in the cement sheath. This assumption may be valid for abandoned wells in the specific field studied, but may not be generalised to the abandoned wells in other fields. In an experimental and geochemical stimulation study on cement degradation, Connell et al. (2014) found that the cement degradation was related to the flow rate and the deficit in the calcium concentration in the CO_2 saturated brine. A numerical simulation model was developed based on this relationship to predict the erosion of cement around a wellbore. The simulation focused on a cemented interval over the seal above the reservoir. It was assumed that the seal is effectively impermeable and a microannulus has developed on the interface between the cement and the seal.

A couple of hypothetical scenarios were simulated in the study by Connell et al. (2014). For example, it was found that for a flow channel of 0.01 cm width, the erosion front took 8 years to travel 50m for a high deficit in calcium solubility (~400 mg/l) and a pressure gradient (above the hydrostatic gradient) of 0.5 MPa/100m. 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 25m after 12 years. Since the rate of migration drops with distance up the flow channel, the remaining 25m for the 0.005cm case would have taken considerably longer than the first 25m. After the erosion front had broken through the cemented zone of the seal, there was an initial rapid increase in the volumetric flow rate, which would represent a loss of containment of stored CO_2. These hypothetical scenarios presented may represent worse case situations and highlight the important role of microannulus in connectivity between different geological units.

3 Well failure rates

Poor well integrity is a considerable issue in oil and gas production operations. A number of studies have been carried out which indicate that there is not full integrity in a significant percentage of all wells. Since the CSG industry in Australia is relatively young (from middle 1990s), publications on CSG well failure have been quite scarce. As such, this section reviews well failure rates reported in open international literature for conventional onshore oil and gas wells and some of CSG wells in North America and Scandinavia. One study on onshore gas well integrity in Queensland is included in the review.

Because conventional oil and gas and shale gas wells are drilled to much greater depth than CSG wells, they are subject to higher temperatures and pressures and have more casing layers. As a result, their failure rates are expected to be higher than for CSG wells. Therefore, extrapolation of findings from overseas studies to Australian conditions with generally relatively shallow wells (typically 350 – 1000 m) has to be done with great care. Nevertheless, the findings from conventional oil and gas and shale gas wells are useful in gaining understanding of possible failure mechanisms potentially relevant to CSG wells, and for obtaining upper bound failure rates.

3.1 Oil and gas well failure rates in Ohio and Texas, USA

Kell (2011) reported a comprehensive study on groundwater pollution incidents related to conventional oil and gas activities in Ohio and Texas, USA. The study covered a very large well population at different phases of the well life (Table 3.1).

Table 3.1.Summary of well numbers in the Kell study (2011).

Number of wells	State	
	Ohio (1983 – 2007)	Texas (1993 – 2008)
No. of wells drilled	34,000	187,788
No. of hydraulic fractured wells	27,969	> 13,000
No. of producing wells	50,342 – 64,830	237,136 – 253,090
No. of wells plugged	28,000	140,818

The average depth of wells drilled in Ohio ranged from 1140 m to 1446 m (3745 feet to 4745 feet) during the study period (1983 – 2007). In Texas the average depth was 2517m (8,258 feet) in 2007. The groundwater pollution incidents and related pollution causes are summarised in Table 3.2, which shows that for well-related groundwater pollution incidents, the pollution from the orphaned wells had the highest number of reported incidents. For the non-well-related incidents, the pollution from reserve pits or storage tanks had the highest number of reported incidents.

King and King (2013) estimated the barrier and well failure rates based on the study by Kell (2011), as summarised in Table 3.3. The barrier failure rate ranged from 0.1% to 0.035% and the well failure rate was one order of magnitude lower (0.004% for newer wells and 0.02% for older wells) than the barrier failure rate. A well barrier is defined as a means of containing wellbore pressure and fluids, and well failure is defined by King and King (2013) as "all well barriers failing in sequence and a leakage pathway being created across all the well barriers". This definition of well failure is consistent with the definition of well breach adopted in this report.

It should be noted that the study by Kell (2011) relied on reported incidents. It is possible that other wells exhibited integrity issues but did not result in contamination of a drinking water well or were not noticed and reported. Hence, 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 3.2. Summary of groundwater pollution incidents at different stages of the well life cycle (Kell 2011). NB: Number of well-related incidents (subsurface pollution) are shown in parenthesis.

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

In both Ohio and Texas, no groundwater contamination incidents related to hydraulic fracturing were identified during the study period during which large volume, multi-staged hydraulic fracturing operations for shale gas well stimulation were carried out in over 16,000 Barnett shale wells. This may be because wells are characterised immediately before stimulation and are still young, so the failure mechanisms described earlier may have not yet had a chance to develop. Intensive, ongoing monitoring of stimulated wells would be required to establish if elevated rates of groundwater contamination could be expected over the longer term.

Table 3.3. Estimates of well barrier failure and well failure (modified from King and King 2013).

State	Number of wells	Barrier failure frequency range (containment present)	Well integrity failure range (containment lost)	Leaks to groundwater by sampling	Data source
Ohio	64,830	0.035% in 34,000 wells (0.1% in older wells – worst case)	0.06% for all wells	Details not available	Kell (2011)
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	Kell (2011) Texas ground water protection council data (1997-2011)
Texas	16,000 horizontal, multi-fractured	No failure reported	No failure date or pollution reported	No well associated pollution	Kell (2011)

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 (2009) conducted a comprehensive evaluation of the potential for gas and CO_2 leakage along existing oil and gas wells by analyzing a large dataset collected by the Alberta Energy Resources Conservation Board (ERCB). The database contains information for more than 315,000 heavy oil, shallow and deep gas and injection wells in the province of Alberta, Canada. The ERCB also records well leakage at the surface as surface-casing-vent flow (SCVF) through wellbore annuli and gas migration (GM) along the outside of the casing. The SCVF occurs when gas enters the exterior production-casing annulus from a source formation below the surface-casing shoe and flows to surface 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 3.1). It is important to note that while gas leaks can occur in one barrier, secondary barriers will contain the pressure and prevent a leak to the outside (King and King 2013). The ERCB requires that all wells drilled and cased be tested for SCVF within 60 days of drilling-rig release and before final abandonment. Wells that have positive SCVF and exhibit gas flow rates greater than 300m^3/day, or have a stabilised surface casing buildup pressures that is greater than the water hydrostatic pressure gradient (9.8kPa/m) to the depth of the surface casing shoe, or have liquid hydrocarbon flow or saline-water flow, must be repaired immediately.

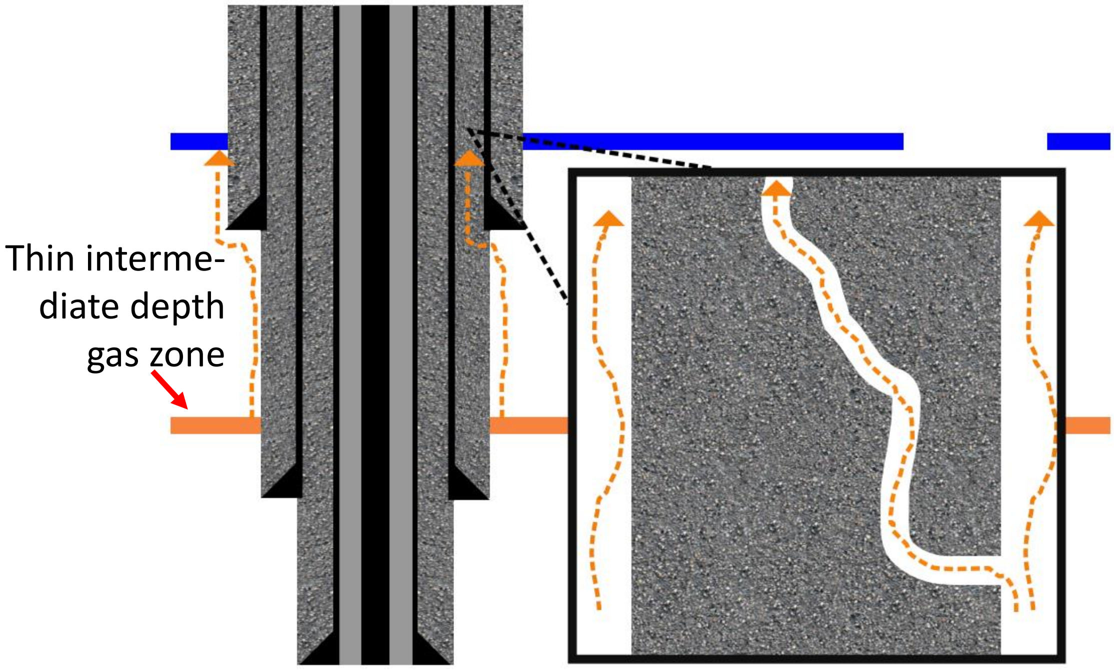

Figure 3.1. Schematic of gas migration (left side of wellbore) and surface casing vent flow (right side of wellbore), originating from a thin, intermediate source depth zone (modified from Dusseault et al. 2014).

Insufficient cement height in the annulus or poor quality cement is responsible for the SCVF and GM. Producing reservoirs are often not the source for the SCVF and GM (Watson and Bachu 2009). As illustrated in Figure 3.1, the gas for the SCVF and GM commonly originates from the thin intermediate depth gas zone. The wellbore interval in the reservoir and adjacent formations is often sealed with high quality cement. During a cement job, the cement slurry at the bottom interval (reservoir and adjacent formations) is subjected to the highest hydrostatic pressure and can be significantly higher than the pore pressure in the surrounding rock formation. As a result, a significant amount of water is lost to the rock formation, forming a dense cement with a good seal (Dusseault et al. 2014). Conversely, intermediate and shallow depth intervals are often sealed with lower quality cement with a number of filler additives, which don’t always generate good primary cement seals (Watson and Bachu 2009).

Figure 3.2 shows historic drilling activity and occurrence of SCVF/GM in Alberta over the last 100 years, both as a percentage of wells spudded in a given year and as cumulative over time (Figure 3.2a and b). As shown in Figure 3.2b, the percentage of cumulative wells with SCVF and GM is approximately 4.6%. The ratio of wells with SCVF and GM to the wells spudded decreased from over 4% in 1995 to below 2% in 2005 (Figure 3.2a), probably as a result of important regulatory changes coming into effect, which require that any leaking wells be repaired before well abandonment. An alternative explanation for this reduction is probably due to the age of wells. The number of wells spudded since around 1995 had increased significantly. These relatively new wells had a maximum age of approximately 10 years. As a consequence, the well failure mechanisms leading to the SCVF and GM may have not sufficiently developed.

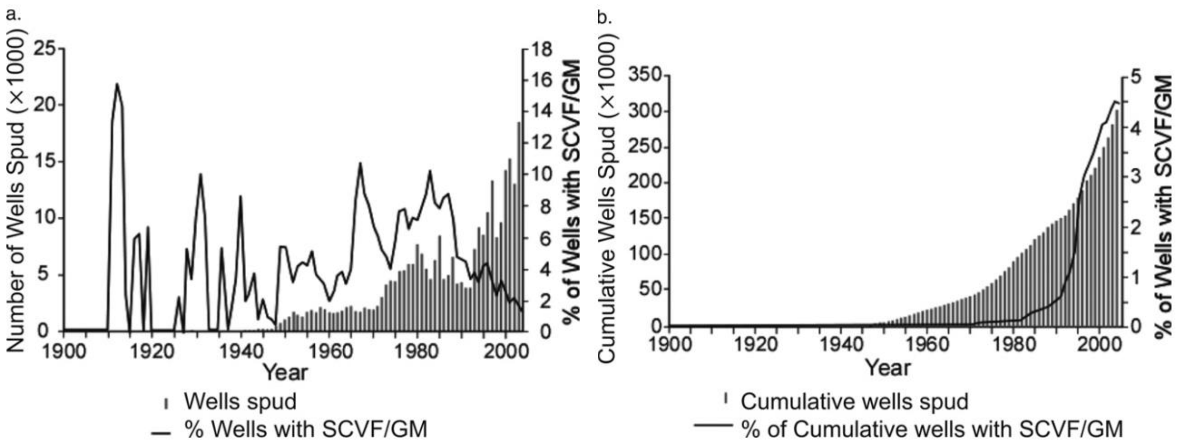

Figure 3.2. Historical levels of drilling activity and SCVF/GM occurrence in Alberta: (a) by year of well spud and (b) by cumulative wells drilled (from Watson and Bachu 2009).

Watson and Bachu (2009) identified six factors that have a major impact on SCVF and GM:

- Geographic area
- Well deviation
- Well type
- Abandonment method
- Oil price, regulatory changes and SCVF and GM testing
- Uncemented casing and hole annulus.

Some of the factors that may be relevant to CSG wells are discussed briefly below.

Geographic area

Watson and Bachu (2009) noted that although the occurrence of SCVF/GM is not limited to a particular area, they found that the occurrence is more likely in a test area designated by ERCB for special testing requirements for leakage. Table 3.4 provides a comparison of SCVF/GM occurrence in Alberta with the test area. The SCVF/GM rate is significantly higher in the test area than the average value in Alberta (4.6% in Alberta versus 15.5% in the test area). Although the authors of the paper (Watson and Bachu 2009) speculated that the greater percentage of reported leakage may be reflective of the testing requirements, they presumed that the testing requirements in the test area were designated based on historical problems in the area.

Table 3.4. SCVF/GM occurrence in a test area compared with Alberta province (from Watson and Bachu 2009).

	Alberta	Test area	Percentage in the test area	Deviated wells 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%

The occurrence of SCVF/GM in a particular geographic area may reflect geological conditions prone to SCVF/GM or particular activities in the area that would promote well leakage. Saponja (1999) discussed typical geological formations that made obtaining and maintaining an adequate cement seal much more difficult in the test area. Furthermore, enhanced oil recovery and other stress-inducing operations that are performed in the area can significantly increase the potential for SCVF/GM occurrence (Dusseault and Jackson 2014).

Well deviation

As shown in Table 3.4 and Figure 3.3, well deviation has a major impact on the occurrence of SCVF and GM in the test area. The rate of occurrence of SCVF and GM is much higher for deviated wells than for vertical wells in the test area (average 66% for deviated wells versus 15.5% in the test area). It was suspected that poor casing centralisation was the main reason for the poor cement seals and the resulting enhanced well leakage. An eccentric casing 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.

Well type

The study by Watson and Bachu (2009) showed that the drilled and abandoned wells (no casing was installed in the well) reported a SCVF/GM occurrence rate at approximately 0.5%, whilst the overall occurrence rate for all wells was approximately 4.6%. The cased and abandoned wells had an overall occurrence rate of approximately 14% with cased wells accounting for more than 98% of all well leakage cases reported. The authors of the study attributed their results to historically more-stringent abandonment requirements for drilled and abandoned wells. It 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 pathway development (Dusseault and Jackson 2014).

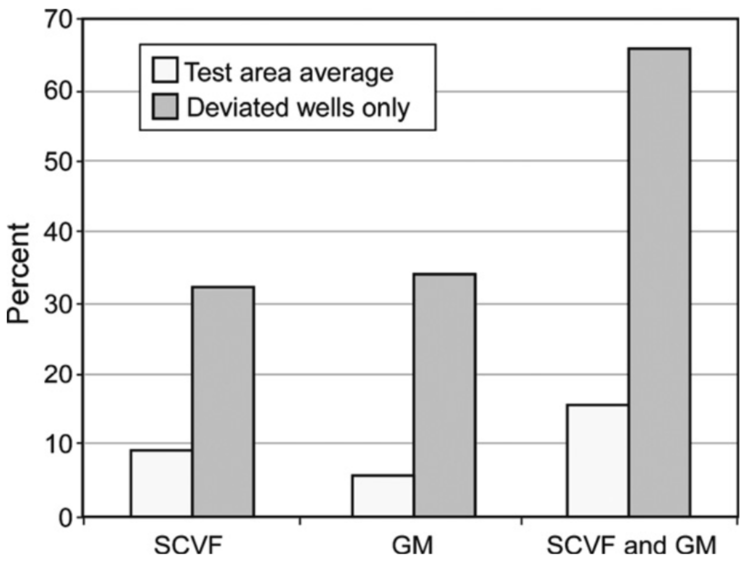

Figure 3.3. Comparison of the occurrence of SCVF/GM in all the wells in the test area in Alberta and in deviated wells only in the same region (after Watson and Bachu 2009).

Well abandonment method

The pre-dominant method for well abandonment in Alberta is 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 (Watson and Bachu 2009). A small subset of wellbores was re-entered to investigate the efficiency of the bridge plug abandonment method. These bridge plugs had been in service for 5 to 30 years. Generally, the cement cap placed on top of the bridge plug was not evident, even though a tour-report review indicated that the cement had been dump bailed on the bridge plug. It is estimated from experience and from this small sample that, over a long period of time (hundreds of years), approximately 10% of these types of zonal abandonments will fail and allow formation gases to enter the wellbore (Watson and Bachu 2009). 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.

Uncemented casing and hole annulus

Watson and Bachu (2009) found that insufficient cement height and an openhole annulus are the most important indicators for SCVF and GM. They have significant impact on external casing corrosion which can create potential leaks through the casing wall. Based on the analysis of well logs of 142 wells to assess the casing and the cement bond quality, it was observed that:

- The majority of significant corrosion occurs on the external wall of the casing;
- A significant portion of wellbore length is uncemented; and
- External casing corrosion is most likely to occur in areas where there is no or poor cement.

These observations are illustrated in Figure 3.4.

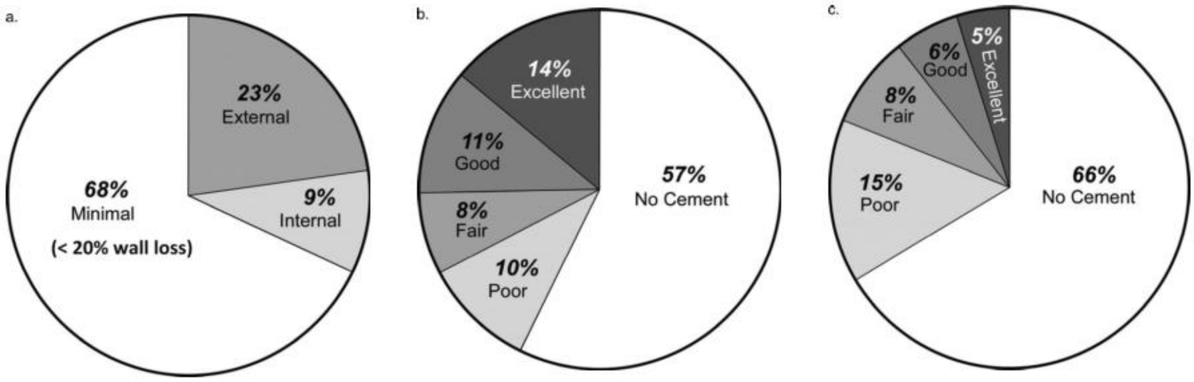

Figure 3.4. Analysis of casing corrosion and cement-bond logs for 142 wells in Alberta, Canada: (a) corrosion location (based on 129,773m logged), (b) casing failure compared to cement top, and (c) external corrosion vs cement quality (based on 10,442 m logged).

Furthermore, based on the analysis of the casing and the cement bond quality in combination with field experience, it was determined that the top 200 m of the cement sheath is generally of poor quality. The effect of low or poor cement quality was evaluated by comparing the location of the SCVF/GM source and casing failure with the cement top. Figure 3.5 clearly shows that over 81% of the SCVF/GM source locations is above the cement top, 11% of the source location is less than 200 m below the cement top, and 8% is more than 200 m below the cement top. Similar observations were made for corrosion induced casing failure. 52% of casing failure is located above the cement top, 29% is less than 200 m below the cement top and 19% is more than 200 m below the cement top.

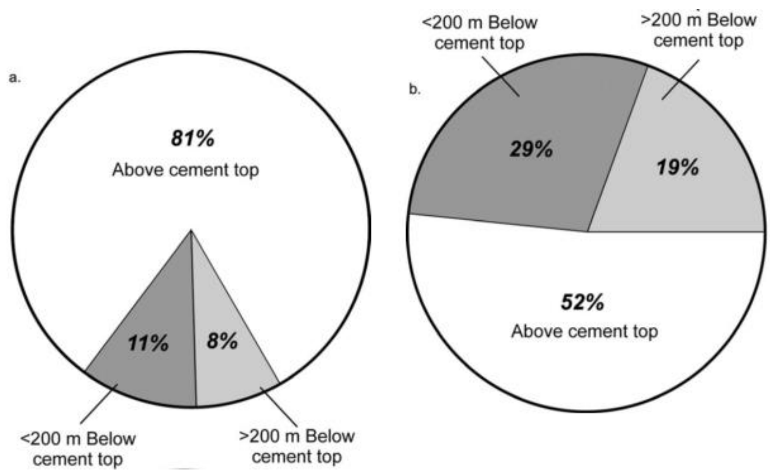

Figure 3.5. Location of (a) SCVF/GM source compared to cement top and (b) corrosion failure (casing failure compared to cement top) in relation to 64 wells in Alberta.

Some wells showed that external casing corrosion was located in the area with good cement quality. Upon further investigation, it was found that in most instances channelling within the cement sheath accounted for the external casing corrosion.

It was further found that it is very difficult to monitor cement deterioration with time using cement bond logs for a number of reasons, such as technology changes in cement-evaluation tools and interpretation, and different wellbore conditions when the cement bond logs were acquired at different times.

3.3 Coal seam gas well failure rates in the San Juan Basin, USA

The San Juan Basin ranks as the most prolific gas producing basin in the U. S. and was the first major gas province to be commercially developed for coal seam gas (or coalbed gas, CBG in the USA). The major coal-bearing unit in the Basin is known as the Fruitland Formation and coal seam gas production occurs primarily in coal seams of the Fruitland Formation. Some coal seam gas is trapped in the underlying and adjacent Pictured Cliffs Sandstone. Many wells are completed in both zones (US EPA 2004).

The first field-wide coalbed methane development began in the late 1970's to mid 1980's in the San Juan Basin. Coal seam gas wells range from 168m to 1220m (550 feet to 4,000 feet) in depth, and about 2,550 wells were operating in 2001 (US EPA 2004).

Similar to the CSG production in the Surat Basin in Queensland, Australia, CSG production from coal seams in the San Juan Basin requires depressurisation in the coal seams by pumping water out of coal to release gas. Drilling and production for coal seam gas from the Fruitland Formation have raised concerns about aquifer protection and have resulted in operational reviews and changes. The primary concern has been natural gas migration into groundwater (Beckstrom and Boyer 1993). To address such concern, a set of sampling, analytical, and investigative techniques were developed to address the source of natural gas in groundwater at the time and has since evolved into standardised methods and protocols used throughout the Basin.

Casing head pressure testing (or bradenhead testing) has been instrumental in identification of defective gas wells. The San Juan Field Office of the Bureau of Land Management has aggressively pursued bradenhead testing for casing head pressure measurement since 1991 (BLM 2010). Operators in the Basin are required to survey all wells and measure and record tubing, casing and intermediate casing pressures. Should casing pressures be encountered, a mandated testing protocol is used to determine if they are due to leaky casing. Beginning with the casing head valve, annular spaces are opened sequentially and the blow down time and flow rates recorded. As each annular space is blown down, the pressure in the adjacent annulus is monitored for any changes at five minute intervals for up to 30 minutes. A drop in pressure in the adjacent annular space usually indicates a leak. Wells with residual pressures after a 30 minute test interval may also indicate a casing leak. A threshold pressure of 172 kPa (25 psi) for wells in a non-critical area or 34.5 kPa (5 psi) for wells in a critical area is established as the minimum threshold pressure required for sampling and laboratory analysis of both produced and casing head gases. If the gases are similar in composition, and/or if a casing leak is detected, the operator must file and implement remedial action plans (Armstrong et al. 2009). The critical groundwater areas constitute an approximate 1 mile buffer zone surrounding domestic wells where methane has historically been documented at concentrations higher than 1.0 mg/L and casing pressures exceed 34.5 kPa (5 psi). All the other areas are designated as non-critical areas.

Well failure rate in La Plata County

According to a summary report by COGCC (Colorado Oil and Gas Conservation Commission, 2000), there were 2,150 gas wells in San Juan Basin, La Plata County, Colorado, by mid 2000. Approximately half of these wells (1,050) are Fruitland Coal wells and the other half are conventional gas wells usually completed in the deeper formations. All gas wells in the county had been tested for casing head pressure annually since January 1991. Since then approximately 254 leaking wells were identified and required repair, either by replacing the well head seals or placing cement outside of the production casing at depth to isolate groundwater aquifers and other geological zones from leaking gas. Most wells only need to be repaired once, but some wells were repaired twice making a total of 269 repairs. It was reported approximately 36 repairs out of the total 269 repairs had been performed on Fruitland Coal wells. It is not known from the report whether any coal seam gas well required repair twice. Assuming the leaking coal seam gas wells were repaired once, this would give an estimated failure rate of 3.4% for the Fruitland coal wells.

Well failure rate in Ignacio-Blanco field

Casing head pressure measurements for all the gas wells in the Ignacio-Blanco field for the 19 year period between 1992 to 2010 were documented in a report by the Bureau of Land Management (BLM 2010). The gas wells included conventional gas wells, coal seam gas wells and the coal seam gas wells converted from conventional gas wells. Table 3.5 summarises casing head pressure data (or bradenhead pressure) for the purpose-drilled coal seam gas wells (i.e., not including the coal seam gas wells converted from conventional gas wells).

It is important to note that the casing head pressures summarised in Table 3.5 reflect initial pressure after a minimum of 10-14 days closure of the bradenhead valve. Furthermore, the age of the wells is not included in the table, nor are the well completion type and the location of the wells (i.e., if located in critical or non-critical areas). Well failure rate for each year is calculated as a percentage of the number of wells with casing head pressure greater than 172 kPa (25 psi) over the total number of wells tested. As shown in Table 3.5, the well failure rate for coal seam gas wells in the field ranges from 1.3% to 8.6% with an average of 3.6%. The average number of wells measured for casing head pressure is approximately 400 per year.

3.4 Oil and gas failure rates in the Gulf of Mexico, US

In the Gulf of Mexico, US, approximately 10 per cent of wells reached sustained casing pressure (SCP) within one year of being completed, and this figure rose to 50 per cent after 15 years of production (Bannerman et al. 2005). This sustained casing pressure state indicates that there is a well barrier failure and possibly a well integrity failure through one or more of the cement sheaths or cased intervals. Note that the leakage path to pressurised reservoir fluids is not necessarily within the production reservoir.

3.5 Oil and gas failure rates in offshore Norway

In offshore Norway 18% of the wells surveyed in a pilot study (75 out of 406 wells surveyed) had integrity failure, issues or uncertainties, and 7% of these are shut in because of well integrity issues according to the National Petroleum Safety Authority (Vignes and Aadnoy 2010).

Table 3.5. Comparison of 1992 – 2009 Bradenhead test statistics (data from BLM 2010).

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
No. of CBM wells tested	360	455	459	457	455	440	323	420	227	560	81	622	615	581	118	613	77	610	85
Casing head pressure (0>&<14kPa or >0 & < 2 psi)	293	282	373	394	408	385	266	377	190	491	65	508	ND	514	101	525	65	447	59
Casing head pressure (14-172kPa or 2 –25 psi)	54	58	75	46	34	45	44	32	27	52	9	73	ND	50	14	75	11	97	19
Casing head pressure (>172kPa or >25 psi)	13	15	11	17	13	10	13	11	10	17	7	17	ND	17	3	13	1	23	7
CBM well failure rate % (>172kPa or >25psi)	3.6	3.3	2.4	3.7	2.9	2.3	4.0	2.6	4.4	3.0	8.6	2.7	ND	2.9	2.5	2.1	1.3	3.8	8.2

NB: ND = no data

3.6 Water bore failure investigations in the Surat Basin, Australia

In establishing field monitoring methods and guidelines to determine water bore and CSG well integrity, SKM conducted an evaluation of water bore integrity in the Surat Basin in Queensland using the NGIS (National Groundwater Information System) database (Commonwealth of Australia 2013). This database was compiled from historical data on water bores collected and archived by Queensland Government departments and other states. The database contains a vast amount of data and information on registered water bores. Records of 10,318 water bores were found within the Surat Basin up to December 2012.

The fields of the database considered directly relevant to water bore integrity are:

- Bore depth
- Target aquifer/stratigraphy
- Groundwater chemistry
- Groundwater level
- Bore design and construction (materials, cementing, depth, screened/open section)
- Drilling contractor
- Age
- Status (in use/abandoned/decommissioned).

However, it was found that the data is highly incomplete and the vast majority of bores recorded in the database do not have data/information in all fields.

The database was filtered for key bore attributes that are considered to be highly correlated to bore integrity and well represented across the broad bore population. The key bore attributes were identified to be bore age and type of casing materials. The identification assumed that all bores are designed to have a life expectancy beyond which they lose their integrity and fail, and all the materials used to construct the bore have a finite lifespan and will deteriorate with time. Furthermore, a better understanding of the groundwater system with time and the need to protect the groundwater resources has led to technological improvements such as the employment of better methods and better materials for bore design and/or construction, and the application of more stringent mandatory legislation and regulations for bore design and construction.

Figure 3.6 shows the age classification of the water bores in the Surat Basin. The data were grouped into the following age classes based on key dates when more stringent regulations were published and improvements were made in casing materials.

- Pre 1954. The Queensland Parliamentary Paper “Artesian Water Supplies in Queensland” was published and mandatory second cementing introduced in the GAB (Great Artesian Basin) in 1954.
- 1955 – 1967. PVC casing became widely available in late 1960s (nominally 1967) and the most optimistic date from which steel casing would still be intact.
- 1968 – 1991. The first comprehensive guidelines for bore construction in the GAB were published in 1991.
- 1992 – 2012. The publication in 1997 of the 1st edition of the Minimum Construction Requirements (MCR).

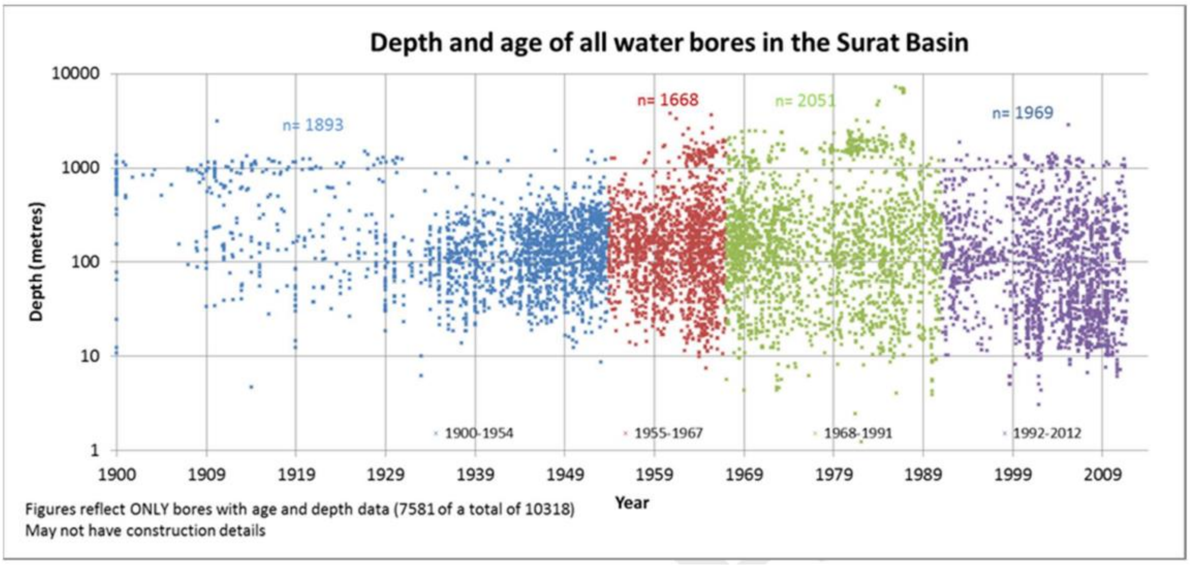

Figure 3.6 Age classification of water bores in the Surat Basin (Commonwealth of Australia 2013).

Figure 3.7 and Figure 3.8 show the number of water bores with steel and PVC/plastic casing, in terms of both new bores and cumulative number of bores respectively. Figure 3.7 illustrates that PVC/plastic has been selected as a casing material for an increasing number of newly constructed water bores from the early 1990s in comparison to traditional steel as a casing material. Figure 3.8 shows that the ratio of water bores cased with steel to that with PVC/plastic is approximately 6 to 1.

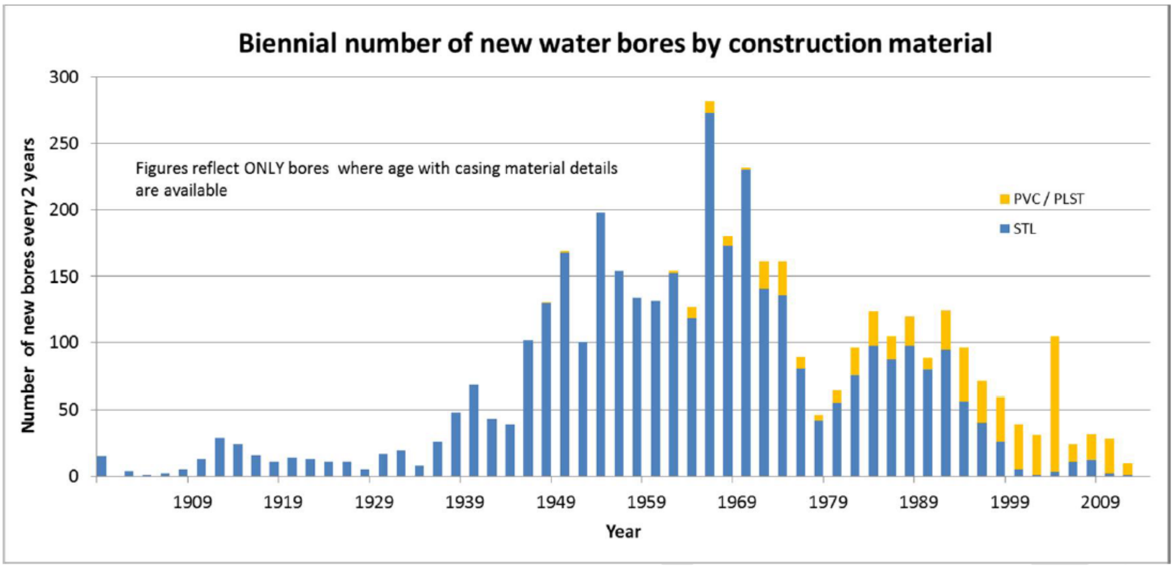

Figure 3.7. Bore age and casing materials for new water bores constructed for every two years (Commonwealth of Australia 2013).

Earlier case studies by GHD (2010) indicate an “optimistic” lifetime of steel in a water bore to be about 45 years and a maximum best estimate of 25 years. In corrosive (high salinity/low pH) environments, however, the lifetime of steel casing is much shorter; between 7 and 13 years. The life expectancy of PVC is estimated to be 50 – 100 years. PVC casing has been widely available from the late 1960s. These estimates of water bore lifespan come from mostly uncemented wells. Cementing of wellbores is likely to significantly extend the average lifetime by separating the steel casing from the corrosive effects of groundwater.

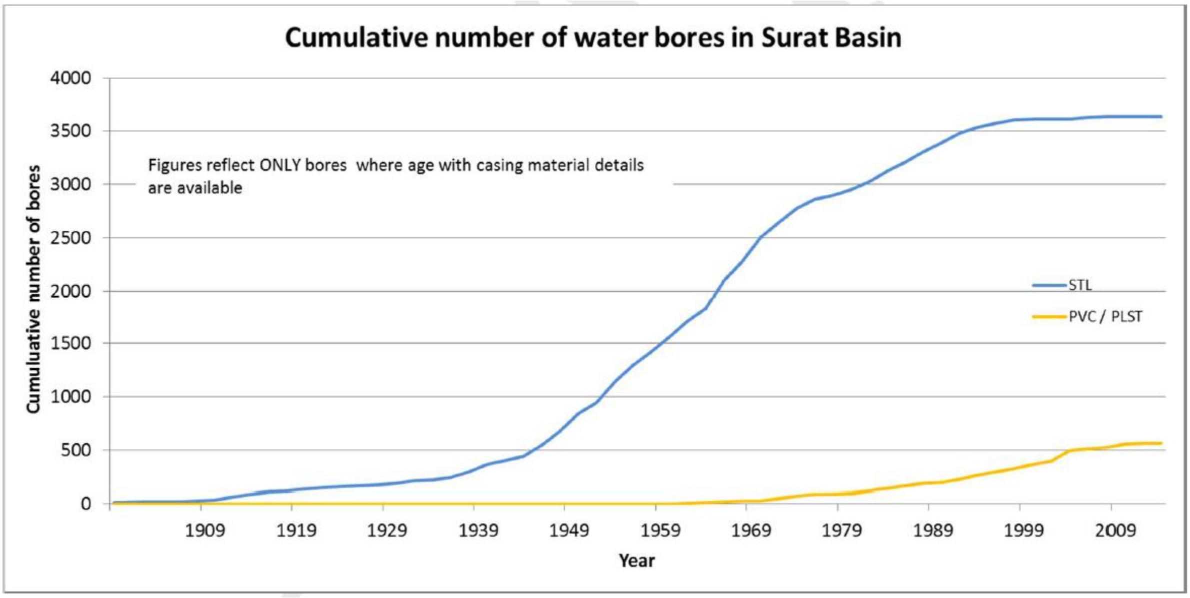

Figure 3.8 Cumulative number of water bores, by age and casing materials (Commonwealth of Australia, 2013).

Based on the optimistic life time of steel in water bores (i.e. 45 years), it was assumed in the Commonwealth of Australia study (2013) that the water bores constructed prior to 1955 will now have poor integrity (1893 bores), i.e., they have experienced well failure. This means that hydrological breach and production breach could occur in the old water bores allowing fluid movement between different geological units (if the bore penetrates multiple aquifers) and/or between the bore and surrounding geological units. This assumption is based on the fact that prior to 1955 nearly all of the water bores would have been constructed using steel casing. The water bores constructed between 1955 and 1967 were also considered to have poor integrity (1668 bores), i.e., well failure is implied on the basis that the steel casing from prior to 1968 would be significantly corroded by now. It was further assumed that the bores using PVC or plastic were considered to have an increased likelihood of good (casing) integrity at present time since PVC does not corrode (but can degrade slowly over time), although good casing integrity does not necessarily lead to good bore integrity since fluid can still migrate behind the casing if the casing external annulus was not cemented or the cement sheath had poor integrity.

3.7 Coal seam gas well failure rates in Australia

To date, there have been few estimates made of failure rates for CSG wells in Australia. The GasFields Commission Queensland (2015) reports statistics from well integrity compliance auditing undertaken from 2010 to March 2015. During this period 6734 CSG exploration, appraisal and production wells had been drilled in Queensland. This involved both subsurface gas well compliance and surface well head compliance testing. For the subsurface equipment, no leaks were reported while 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 0%. For subsurface equipment, the conclusion is that the risk of a subsurface breach of well integrity is assessed to be very low to near zero. In regards to the surface well head leaks, 199 leaks have been reported and have been subsequently fixed.

Estimating CSG well failure rates from failure rates reported for conventional onshore/offshore oil and gas wells or from shale gas wells has to be done with care. Because offshore oil and gas wells are drilled in a different and more difficult environment than onshore CSG wells, their failure rates are expected to be much higher than for CSG wells. Furthermore, CSG wells are shallower than conventional oil and gas and shale gas wells, and therefore subject to lower temperatures and pressures. Also, operating pressures for CSG wells are lower and they have less casing layers (GasFields Commission Queensland 2015). Nevertheless, the findings from conventional and shale gas wells are useful in gaining understanding of possible failure mechanisms of CSG wells, and for estimating upper bound failure rates.

Estimating CSG well failure rates from water bore life expectancies also has its limitations. Failure rates derived for water bores should not be simply extrapolated to CSG wells for a number of reasons, including that cementing the casing in ground can be different for water bores and CSG wells (NUDLC 2012 and DNRM 2013a), and prior to the late sixties cementing was not a requirement for water bores. As discussed above, cement plays a critical role in protecting steel casing from corroding, and hence has a significant impact on well life expectancy.

4 Conceptualisation of well and bore failure pathways for groundwater modelling

Building on the literature review on well failure mechanisms and rates relevant to CSG environments reported in the previous two chapters, this chapter discusses the conceptualisation of likely well and bore failure pathways for the purpose of groundwater flow modelling to support decision making. Key governing processes and hydraulic parameters are discussed in section 4.1. To allow prioritising modelling efforts, the relative impact of different failure pathways is assessed in section 4.2. This resulted in identification and conceptualisation of four major pathways for water movement between strata (section 4.3). A set of appropriate numerical simulators for modelling the hydrological impact of well and bore failure are presented in section 4.4.

4.1 Governing processes and parameters

Very few studies have modelled groundwater impacts, whether water quantity or quality, from failed conventional and unconventional gas wells, exploration bores and water bores. The majority of literature in the shale or coal seam gas discipline focuses on the impact of hydraulic fracturing on the hydrogeology of a system or on the leakage of methane gas (Vengosh et al. 2014). Other studies in the area of CO_2 sequestration tend to focus on the loss of CO_2 rather than migration of water (Lewicki et al. 2007; Nordbotten et al. 2009). The exception is a study by Nowamooz et al. (2015) which described the modelling of methane and formation fluid leakage along the casing of a decommissioned shale gas well, using the DuMu^x multi-scale multi-physics toolbox for flow and transport processes in porous media (Flemisch et al. 2011). Given the paucity of published studies on groundwater impact modelling from well and bore failure, this study provides an overview of governing processes deemed relevant for a quantitative assessment using groundwater models.

The flow of liquid through a permeable matrix can be described by Darcy's law, a gradient law that states that the volumetric flow rate is dependent on the cross sectional area of flow, the resistance of the matrix (or hydraulic conductivity) and the pressure gradient across the matrix. When modelling fluid flow through leaky wells as part of a study on geological storage of CO_2, Nordbotten et al. (2009) assigned effective Darcy permeabilities to each section of the well that crossed a caprock (aquitard). Their model assumed flow along wells occurs primarily through fractured or degraded porous media along the outside of the well casing, including well cements and drilling fluids. The model further assumes these small-scale flow paths can be represented at the larger scale by an effective Darcy permeability.

For flow through wells and bores with compromised integrity, the flow rate of water between the production zone and water bearing aquifers will therefore depend on the cross sectional area of the flow path, the hydraulic head gradient (hydraulic head difference divided by distance between communicating aquifers) between the production zone and surficial aquifers and the effective hydraulic conductivity of the wellbore. Under the assumption that flow takes places across the entire cross sectional area of a cemented well or bore, the cross sectional area of the flow path can be estimated with relatively high certainty from physical wellbore dimensions, the internal cross sectional area of the well/bore or the cross sectional area of the cement annulus around the steel casing. This will not be discussed further in this report. The head difference between the production zone and the surficial aquifers may be measured in the field or estimated using groundwater models, with a somewhat higher uncertainty than the cross sectional area measurements. The parameter that is least straightforward to estimate, and therefore has the highest degree of uncertainty, is the effective well/bore hydraulic conductivity.

The following sections give an indication of possible head gradients (section 4.1.2) and effective well/bore permeability/hydraulic conductivity (section 4.1.3) that may be relevant for modelling the impacts of wells/bores with compromised integrity in Australian CSG developments. Prior to the discussion of possible head gradients between hydrocarbon reservoir and aquifers, the study area used to generate the head gradients is briefly discussed (section 4.1.1).

4.1.1 Study area

A regional-scale numerical groundwater flow model of the Gunnedah Basin has been developed by CDM Smith (2014) for the Groundwater Impact Assessment component of the Environmental Impact Statement for SANTOS' NSW proposed Narrabri Gas Project, NSW. The Narrabri Gas Project will mainly target coal seam gas reserves associated with Early Permian coal seams of the Maules Creek Formation and secondary gas reserves associated with coal seams of the Late Permian Black Jack Group. The groundwater model was used by CDM Smith to predict the potential impacts on groundwater resources within the groundwater impact assessment study area due to water extraction from the coal seams that will be targeted for coal seam gas production. Simulations of water extraction from the coal seams provided regional - scale predictions of depressurisation and drawdown of hydraulic head within the Gunnedah Basin and the associated induced flows between groundwater sources and hydrostratigraphic units. The same model has been used in this study to generate additional information in terms of hydraulic heads across all relevant formations in areas of greatest expected drawdown.

The groundwater model is a MODFLOW–SURFACT model, covering a total area of 53 219 km^2. For groundwater flow simulations, the geological domain was discretised using a combination of 1 km^2 and 5 km^2 cells into 238 rows and 126 columns (see Figure 4.1 for the model grid in X-Y direction). A total of 24 geological model layers are represented (Figure 4.3). Coal seam gas production was simulated using time-varying specified flux (i.e., Neumann) boundary conditions. For this model, the aquitard sequence overlying the Hoskisson Coal represents the key aquitard that will govern the vertical propagation of hydraulic stresses induced in the underlying coal seams by coal seam gas production to the overlying Pilliga Sandstone aquifer. In 15 locations (so-called observations) the vertical head distribution pre- and post-production will be interrogated and used to provide detailed information about hydraulic head gradients that exist between the hydrocarbon reservoir and the main aquifers (see next section). The post-production times are 26, 100, 200, and 500 years since commencement of production (production is assumed to last for 26 years, hence the first timestep is at the end of gas production).

4.1.2 Hydraulic head gradient

The difference in head between the production interval and water bearing aquifers is a key variable controlling the rate of leakage through failed wells/bores. Two distinctively different cases need consideration: i) natural gradients, which are usually small, and ii) anthropogenically enhanced gradients, which may be high, especially in productive CSG well fields. Furthermore, high residual head differences that exist after CSG production ceases, may generate relatively high flow rates through any leaky wells/bores, exploration bores or natural faults.

Prior to CSG production, the hydraulic head distribution in a vertical cross-section comprising an aquitard separating a coal seam gas target formation from a beneficial aquifer can be one of the three following conditions: i) nearly identical heads resulting in a negligible hydraulic gradient across the aquitard, ii) hydraulic gradient is from the production zone to surficial water bearing aquifers, or iii) hydraulic gradient is from the surficial aquifers to the CSG production zone.

In addition to these three location-specific conditions, the hydraulic head gradient prior to production may vary within a single CSG development zone. As an example, the MODFLOW-SURFACT groundwater model of the proposed Santos Narrabri Gas Project which was used in the CDM Smith (2014) report was interrogated to find the hydraulic gradients pre- and post-production for fifteen observation locations (Figure 4.1 and Figure 4.2) around the location of greatest expected drawdown. The model includes a total of 425 proposed production well pairs, providing access to primary (Maules Creek Formation) and secondary (Black Jack Group including Hoskissons Coal) coal seam gas targets. The typical distance between bore pairs is about 1 km.

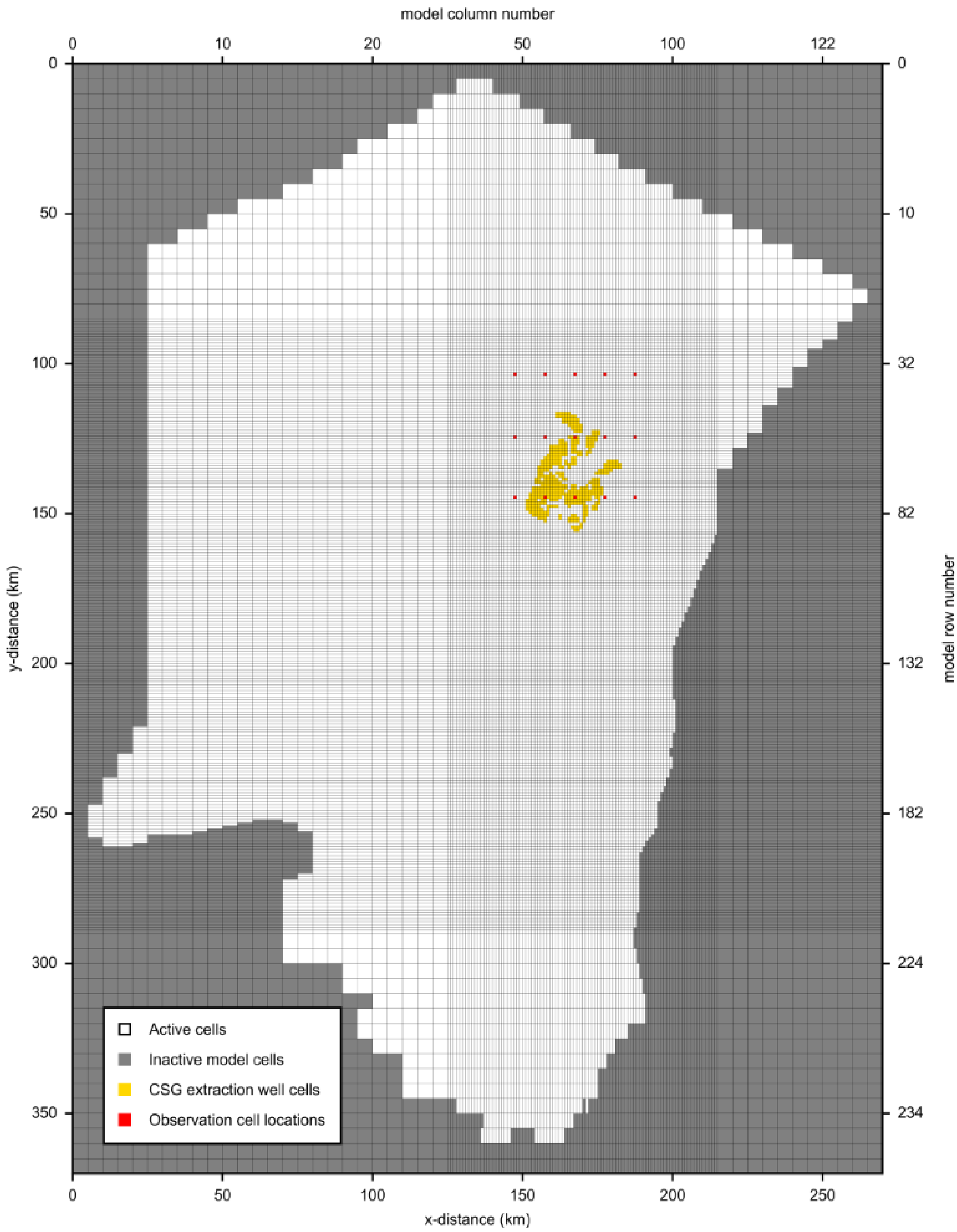

Figure 4.1 Location of the fifteen observation points within the model domain including the proposed Santos Narrabri Gas Project. A close-up of the location of proposed CSG wells is provided in Figure 4.2.

For the northern observation points (Figure 4.4, graphs 1 to 5), the hydraulic gradient is upward, i.e. from the deeper aquifers and production zone (dark blue) to the surficial aquifers (purple). This may be due to irrigation pumping from the relatively shallow Pilliga Sandstone aquifer. In the southern observation points (Figure 4.4, graphs 11 to 14), the gradient is downward, suggesting recharge and movement of water from the surficial aquifers to the production zone. The magnitude of head differences ranged from 30 metres upward to 50 metres downward. This translates to a hydraulic gradient of 0.03 m/m upward and 0.07 m/m downward, respectively.

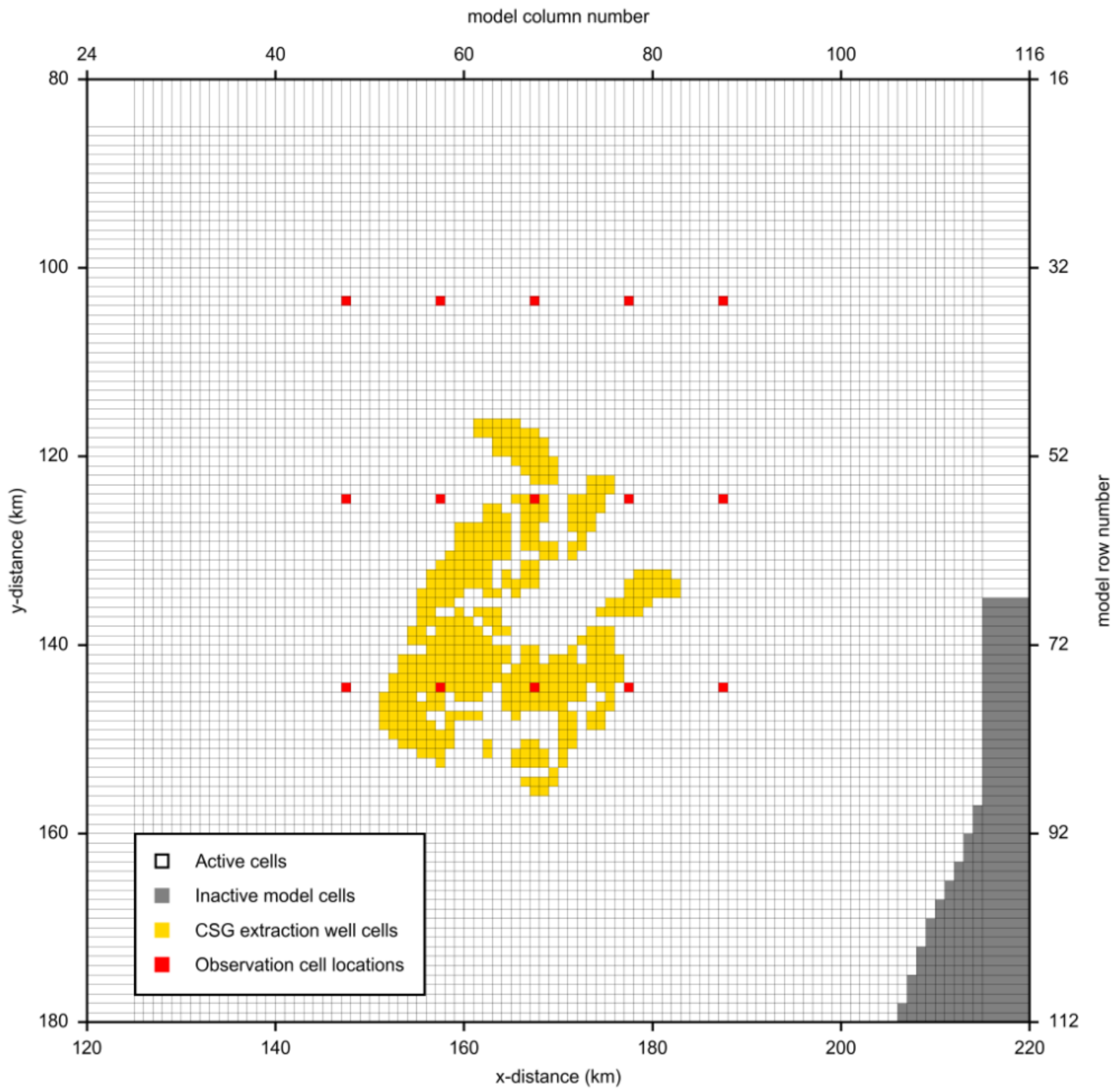

Figure 4.2 Location of the CSG wells within the proposed Santos Narrabri Gas Project.

Greater head gradients in a downward direction, up to three times those of pre-production levels, are seen immediately after production ceases (Figure 4.5). In some cases the hydraulic gradient has reversed (e.g. cell (56,77)), with water now seeping into the coal seam target formations whereas under the pre-production gradient seepage was likely upward. The gradients continue to recover beyond 100, 200 and 500 years (Figure 4.6, Figure 4.7 and Figure 4.8 respectively). However, even after 500 years, the hydraulic gradient has not returned to pre-production levels. In some instances, upward gradients continue to exist throughout the entire pre- and post-production period, e.g. in cell (36, 47), suggesting flow from the coal formations to the Pilliga Sandstone aquifer may occur provided a pathway for flow exists.

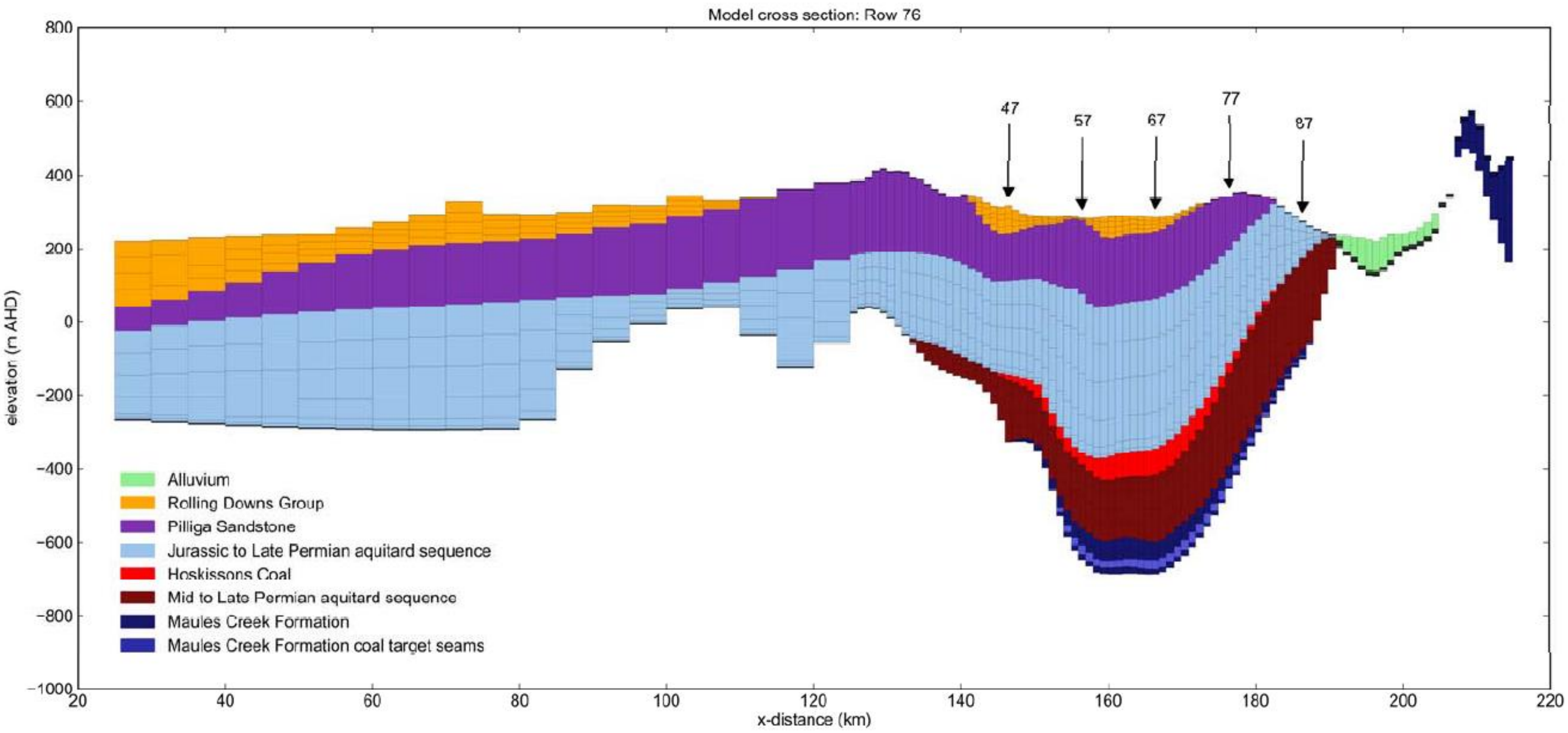

Figure 4.3 Location of the observation points along a model transect.

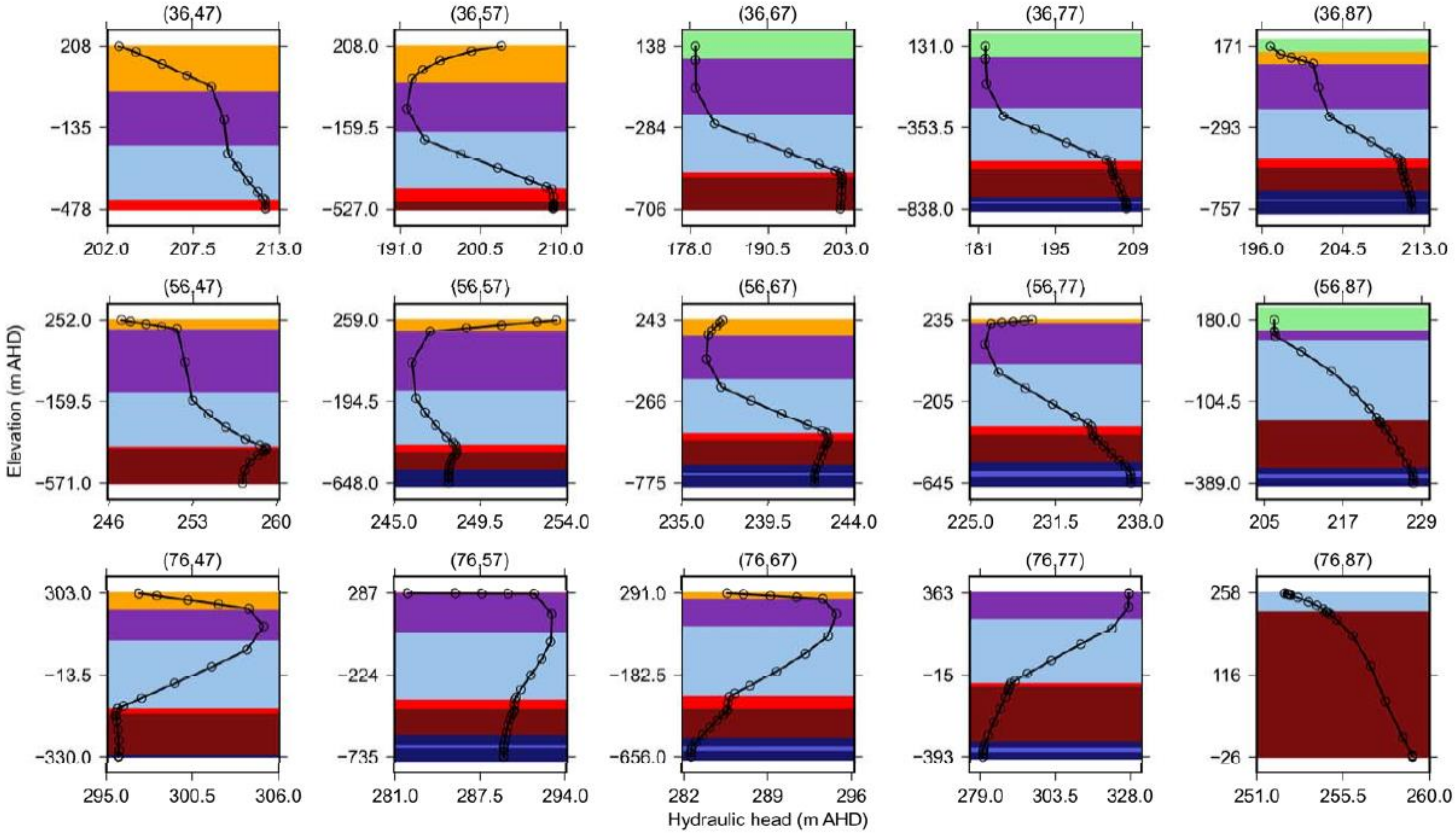

Figure 4.4 Pre-CSG production hydraulic head gradients for cells of the Santos Narrabri Gas Project, with formations described in Figure 4.3.

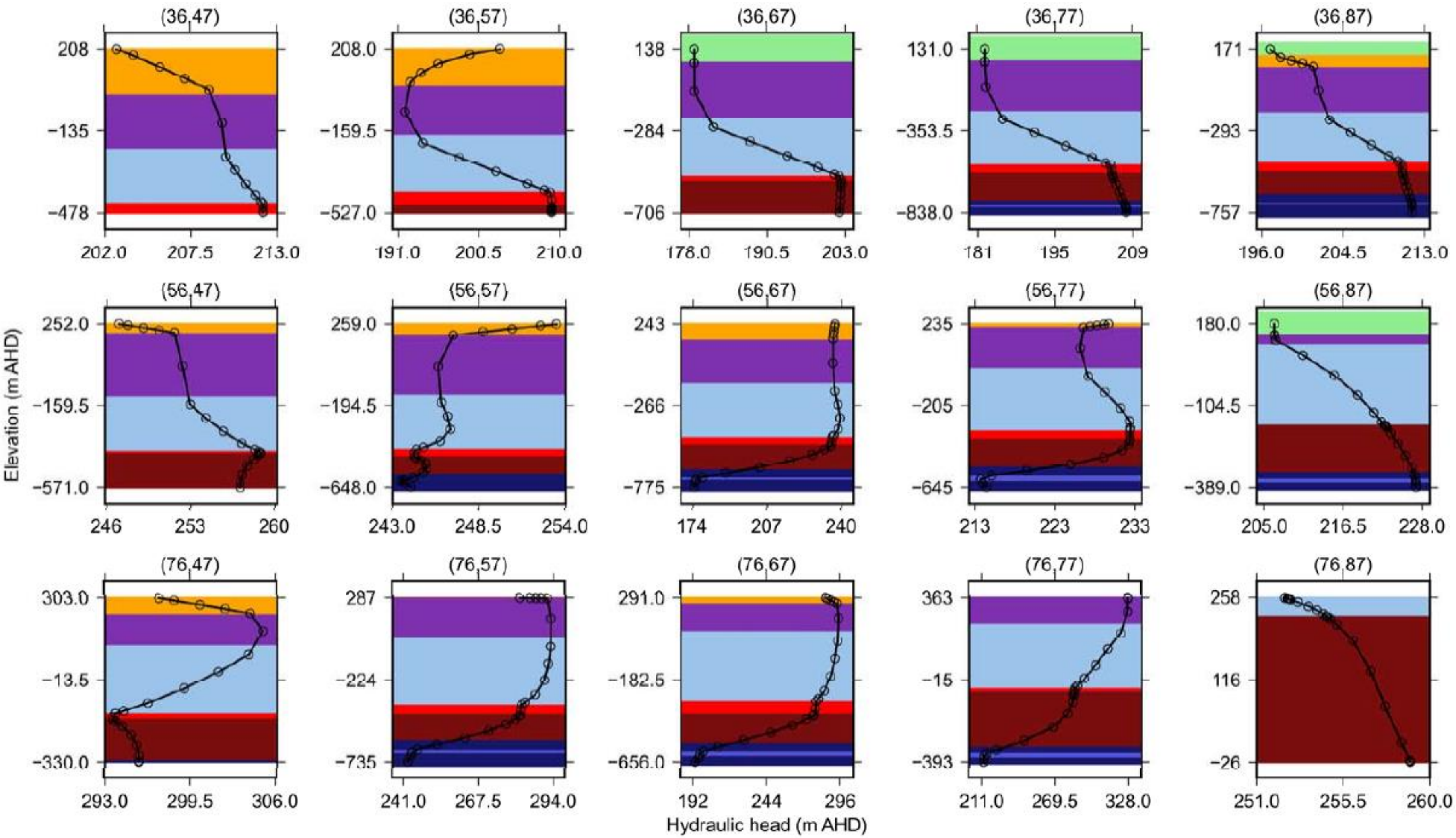

Figure 4.5 Hydraulic head gradients immediately post CSG production (26 years after commencement) for cells of the Santos Narrabri Gas Project, with formations described in Figure 4.3.

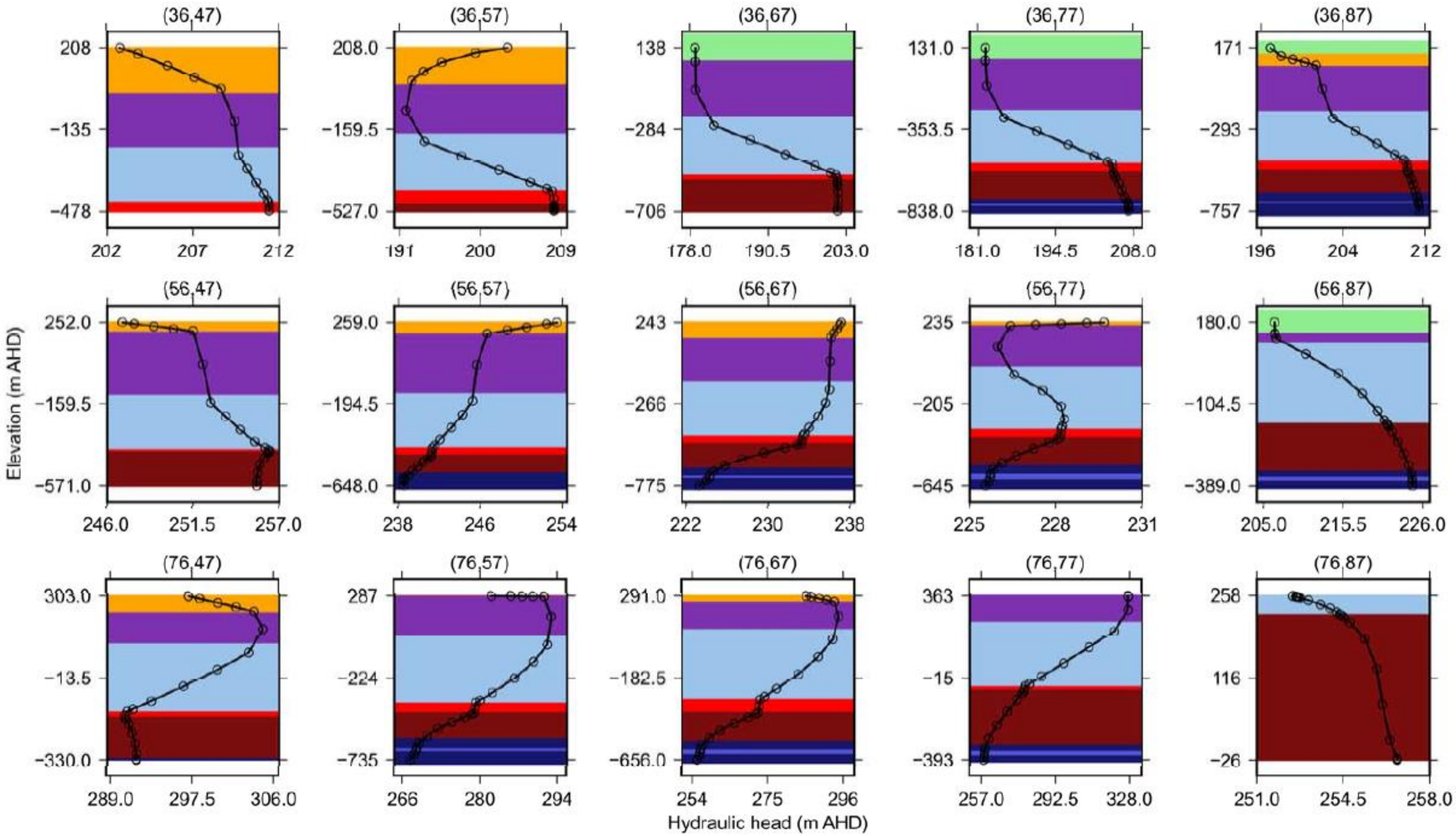

Figure 4.6 Hydraulic head gradients 100 years after commencement of CSG production for cells of the Santos Narrabri Gas Project, with formations described in Figure 4.3. CSG production lasted for 26 years.

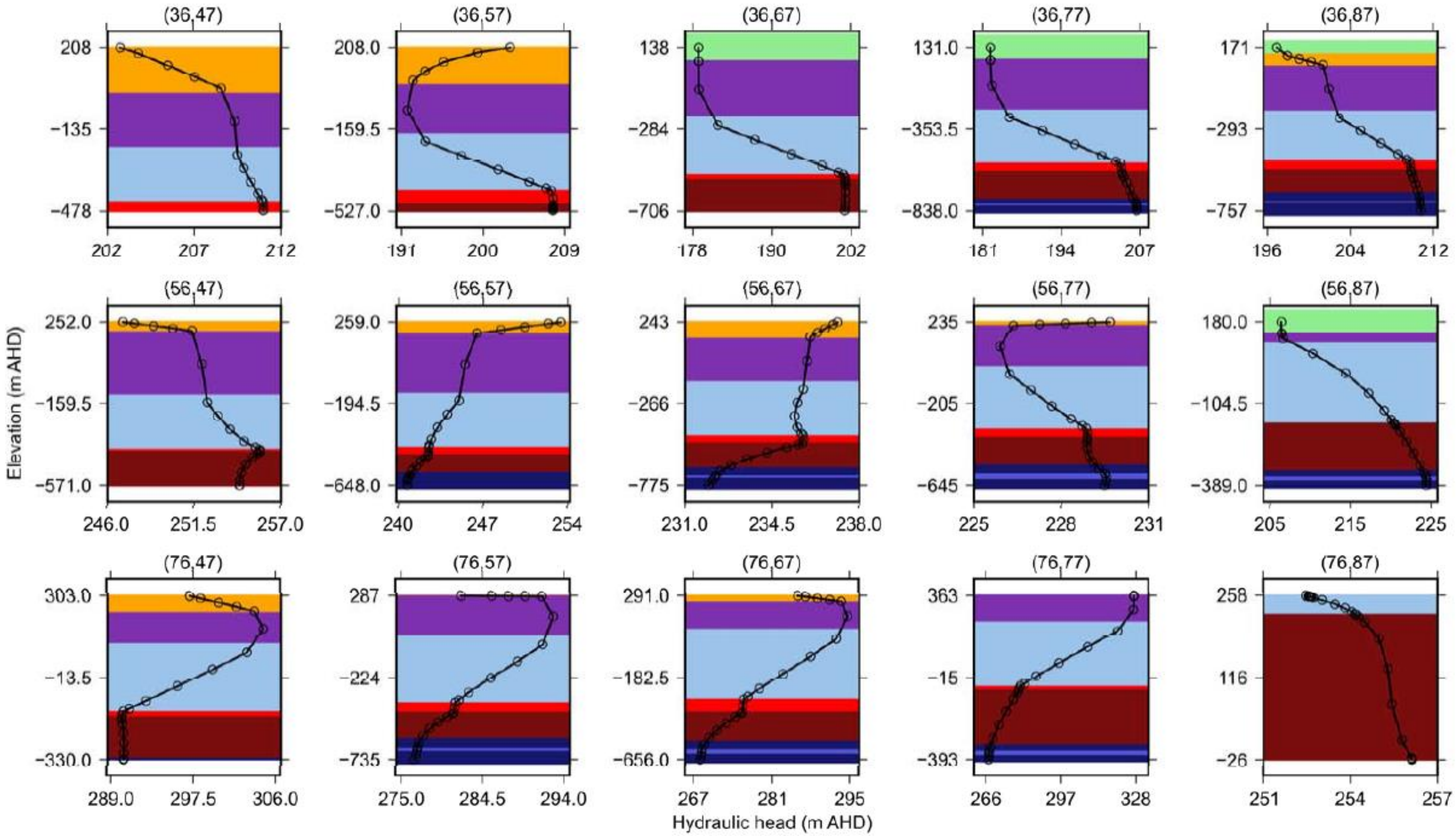

Figure 4.7 Hydraulic head gradients 200 years after commencement of CSG production for cells of the Santos Narrabri Gas Project, with formations described in Figure 4.3. CSG production lasted for 26 years.

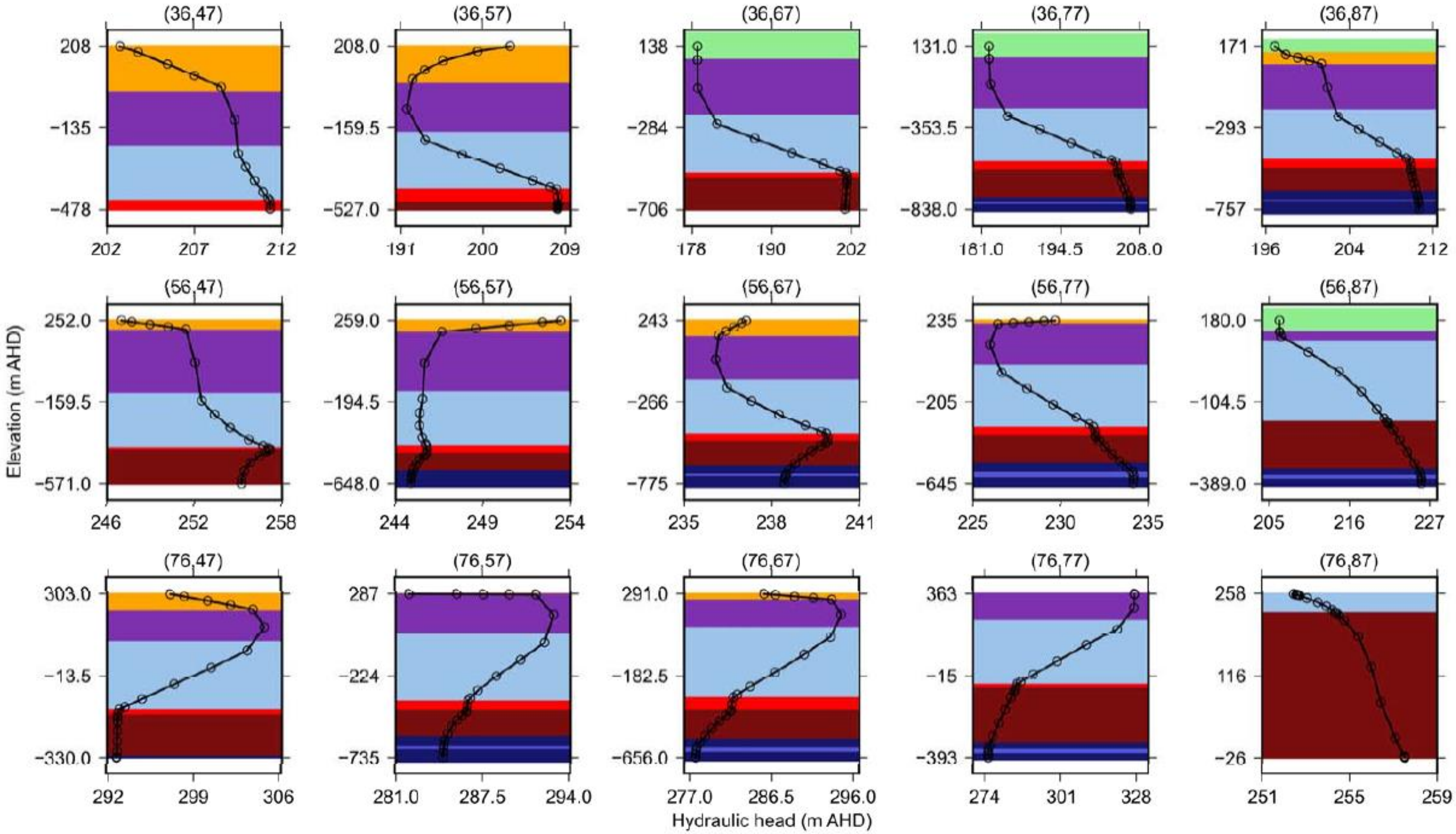

Figure 4.8 Hydraulic head gradients 500 years after commencement of CSG production for cells of the Santos Narrabri Gas Project, with formations described in Figure 4.3. CSG production lasted for 26 years.

The MODFLOW-SURFACT model was also used to produce timeseries of predicted changes in hydraulic head for cells with the highest overall drawdown due to CSG production in the primary (early Permian) coal targets of the Maules Creek Formation (Figure 4.9 and Figure 4.10), and secondary targets (late Permian) of Hoskissons Coal (Figure 4.11 and Figure 4.12). This was compared with the hydraulic heads of the confined Pilliga Sandstone aquifer (a major regional aquifer in the Santos Narrabri project area). The head difference between the Maules Creek Formation production interval and water bearing aquifers due to CSG production was up to 140 metres, but this declined rapidly over 100 years to around 40 metres head difference, and returned to pre-development levels after around 1000 years. The difference for production in the Hoskissons Coal formation was less, at 28 metres, but it also returned to pre-development levels after around 1000 years. The examples shown all produce a downward gradient, presenting a condition that potentially leads to long-term head loss from the Pilliga Sandstone should preferential flow paths due to loss of well integrity exist.

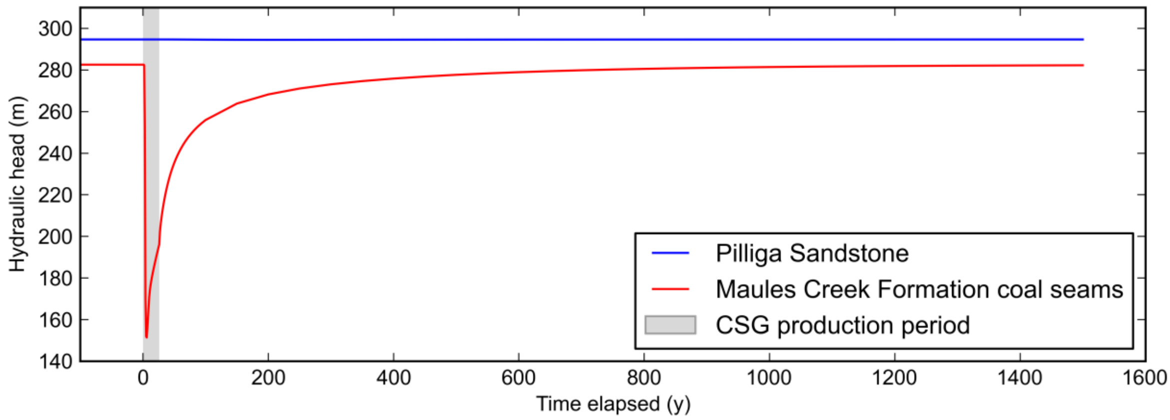

Figure 4.9 Changes in hydraulic head (△H) for cells in the region of highest drawdown in the Maules Creek Formation, compared with heads in the confined Pilliga Sandstone aquifer.

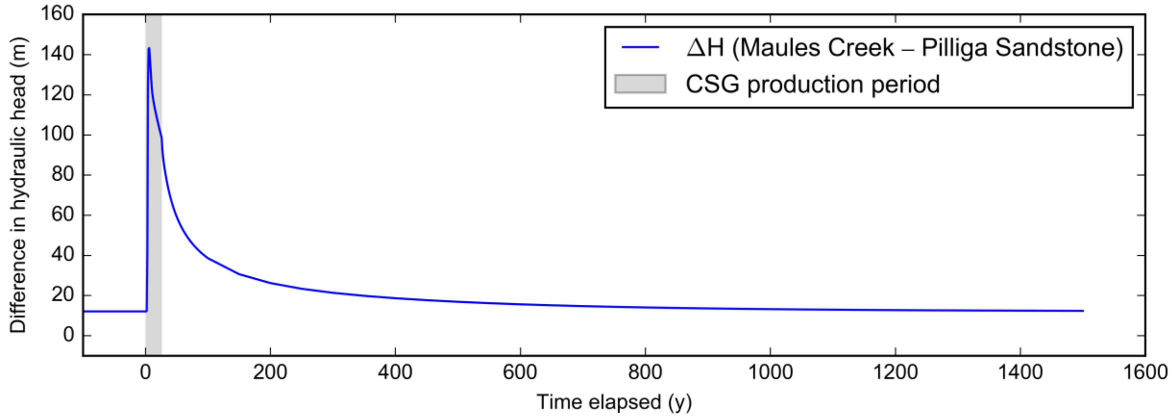

Figure 4.10 Difference in hydraulic head (△H) for cells in the region of highest drawdown between the Maules Creek Formation and the confined Pilliga Sandstone aquifer.

As well as a head gradient, a leakage pathway is also required for flow to occur between surficial aquifers and the production zone. If the expected lifespan of the well, and the resulting creation of leakage pathways, is shorter than the time taken to recover the drawdown in the production interval, there may be a potential impact from the CSG development on the flow through leaky wells.

Previous studies have indicated that a significant proportion of wells do not have full integrity, and that this percentage increases with the age of the wells (Chapter 3). The reported failure rates are significant: i) 0.06 and 0.02% of oil and gas wells respectively in Ohio and Texas had well integrity failure (Section 3.1), ii) 4.6% of oil and gas wells had leakage issues in Alberta, Canada (Section 3.2), iii) in the San Juan Basin, USA, the reported failure rates for coal seam gas wells are 3.4-3.6% (Section 3.3), iv) 10% of offshore wells in the Gulf of Mexico had reduced well integrity after one year of use, increasing to 50% of wells after 15 years of production (Section 3.4), and v) in areas offshore of Norway 18% of the wells surveyed had integrity issues and 7% are shut in because of well integrity issues (Section 3.5). An important knowledge gap remains, however: what this means in terms of consequences on groundwater quality or water balance.

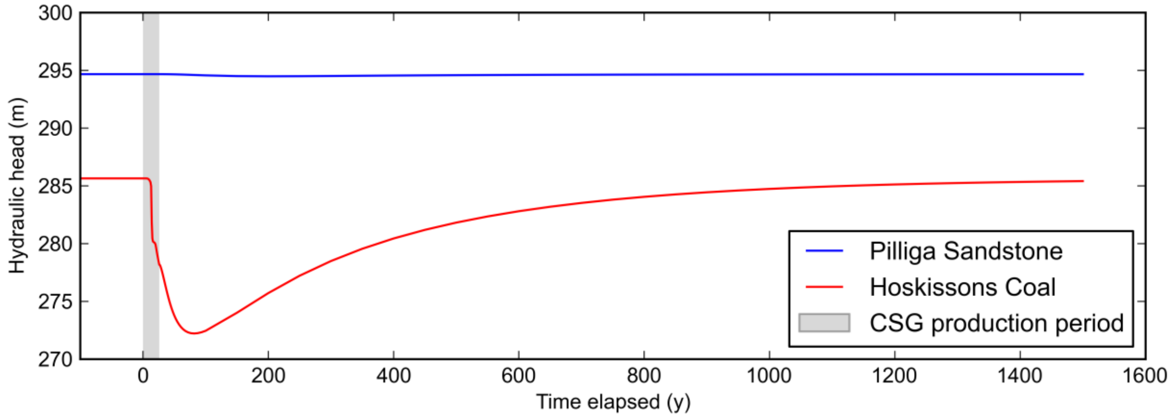

Figure 4.11 Changes in hydraulic head for cells in the region of highest drawdown in the Hoskissons Coal formation, compared with heads in the confined Pilliga Sandstone aquifer.

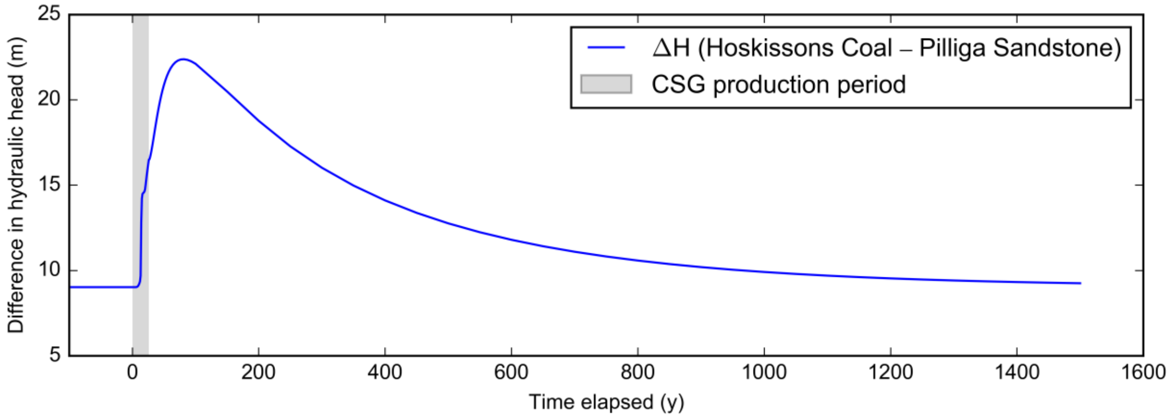

Figure 4.12 Difference in hydraulic head for cells in the region of highest drawdown between the Hoskisson Coal and the confined Pilliga Sandstone aquifer.

Future studies, including taking field measurements, are required to determine whether these measures of gas migration translate to the migration of liquid through the well. Research efforts also need to be focused on the percentage of wells with compromised integrity as a function of age, especially beyond the approximately 50 years that is represented in Figure 3.2b. It would be useful as a first pass analysis to plot the likelihood of compromised well integrity against head gradient decline after production ceases (based on example hydraulic gradient evolutions like those displayed in Figure 4.9 and Figure 4.11). Unfortunately, any current estimates of the likelihood of integrity compromise beyond 50 to 60 years are likely to be unsubstantiated.

4.1.3 Effective well/bore permeability/hydraulic conductivity

For the purpose of water flow through wells/bores with compromised integrity, well/bore length, head difference and cross sectional flow area may be estimated from field measurements with relative certainty. There is less certainty, however, in estimates of effective well/bore permeability or hydraulic conductivity (hydraulic conductivity will be used as it is the preferred terminology in groundwater modelling). There are no estimates of well hydraulic conductivity available for Australian surveys; a survey of field and laboratory measured effective well hydraulic conductivity in the US is reported in Table 4.1. This information may be used as a general guide, but individual well conductivity will be a function of cement type, cement age, the hydrogeochemistry of the different formations at the well location and whether the flow is via the annulus or through the central part of the well. Based on cement core measurements, the hydraulic conductivity ranges from 10^{-7} m/d (10^{-12} m/s) to 10^{-3} m/d (10^{-8} m/s). These values range from very low (typical of very good quality cement) to low (relatively permeable cement). In contrast to the core conductivity, the effective well conductivity based on sustained casing pressure or vertical interference tests was considerably higher, i.e. from 10^{-6} m/d (10^{-11} m/s) to 10^{-1} m/d (10^{-6} m/s). In other words, using core-based conductivity measurements will significantly underestimate the well-scale effective conductivity, and therefore any assessments based on core-based conductivities will underestimate impacts, unless it can be guaranteed that the well does not consist of interconnected voids which would provide preferential flow paths. In the above studies dual-phase flow was not explicitly considered in the determination of effective hydraulic conductivity. Whenever dual-phase flow occurs in the bore or well, relative hydraulic conductivity needs to be determined to account for the effect of the gas phase on the relative hydraulic conductivity of the water phase. The relative hydraulic conductivity of a fluid is defined as the effective conductivity divided by the absolute (single-phase) conductivity. When multiple fluids are present in a reservoir, the flow of each fluid is impeded by the presence of the other phases. Therefore, relative conductivity is a function of the fluid saturation. Determination of relative hydraulic conductivity hence also requires determination of capillary pressure relationships for the cemented bore/well annulus.

To assist in the interpretation of Table 4.1, the different cement classes are outlined in Table 4.2 (after Robertson et al. 1989). Cement is formulated for different temperature and pressure requirements, with higher pressure and temperature cement required for deeper wells. Class C cement is formulated to provide high strength early in the setting process. The different cement classes are available with ordinary, moderate and high resistance to sulfates, which are the leading cause of cement degradation when it is in contact with saline water, such as marine applications and wells within saline aquifers. Class G and H cement may have accelerators to speed up the setting process (this results in higher heat generation and the maximum compressive strength is reached sooner), or retarders to slow down the setting process (this reduces heat generation while full compressive strength will be attained at a later stage).

In the US, 80% of cement used for wells is Class G and H, with 10% Class A and 10% class C. For the rest of the world, 95% of cement used is Class G, with the remaining 5% Class A or Class C. Pozzolans, a finely ground pumice or fly ash, are used to bulk out some types of cement to reduce its density. This is referred to as Pozzmix in Table 4.1.

The hydraulic conductivity of fully hydrated standard cement and concrete is sensitive to the water to cement (W/C) ratio. Generally, increasing conductivities are observed when the W/C ratio increases (see e.g., Jacobs and Whitmann 1992). This is due to the increase in porosity when W/C ratios increase. Higher porosities usually result in higher conductivities, as more pore space is available per unit cross sectional area to conduct the water. Such a dependency is also apparent from the log-linear relationship in Figure 4.13, based on well cement ranging in age from 13-68 years. It may be possible to use these relationships to develop bounds for estimates of effective well hydraulic conductivity from physical measurements of cement porosity.

Table 4.1 Summary of recovered cement core properties from the cement annulus and effective well permeability measured by vertical interference tests or inferred from sustained casing pressure measurements.

Well location	Well completion data/well age/ Cement type	Estimated aperture of microannulus between casing and cement (micron/inch)	Cement core permeability /hydraulic conductivity (lab measured) (mD / m/d)	Cement porosity (lab measured)	Formation type	Formation permeability (mD / m/d)	Formation porosity	Effective well permeability/hydraulic conductivity (mD / m/d)	References
EGL#7, Cranfield, Mississippi	1947/68 years old/Class A or Class D cement	70.55/0.00278 (lower bound)	0.000186 (cement from 2008 cement squeeze) 0.0146 (original cement from 1947)	N/A	N/A	N/A	N/A	N/A	Duguid et al. 2014
CC1, Carbon County, Wyoming	2002/13/light weight Portland cement	N/A	0.001 – 0.04[3] / 8.3E-07 – 3.3E-05	27.28% – 77.93%	Shale	0.06E-03 / 5E-08	N/A	25 / 2E-02 (VIT)[1] (single phase fluid permeability)	Duguid et al. 2013
43-TPX-10, Natrona County, Wyoming	1985/30/ Class G or 50/50 Pozzmix	N/A	6.37E-05 – 0.012 / 5.3E-08 – 1E-05	41.25% – 42.74%	Shale/ Anhydrite/ Limestone	N/A	N/A	N/A	Duguid et al. 2013
46-TPX-10, Natrona County, Wyoming	1996/19/ Class G or 50/50 Pozzmix	N/A	0.0001 – 0.025[4] / 8.3E-08 – 2.1E-05	27.32% 63.07%	Shale/ Limestone	0.06E-03 / 5E-08	N/A	170 / 1.4E-01 (VIT)[1] (single phase fluid permeability)	Duguid et al. 2013
Oil producer, Weyburn field	1957/58/ Portland cement and Pozzolan at ratio of 1:1	N/A	N/A	20% – 40%	Regional seal	0.0002E-03 - 0.2E-03 / 1.7E-10 – 1.7E-07	5% – 15%	7-80E-03 / 0.67 – 6E-06 (VIT)[1] (single phase water permeability)	Hawkes and Gardner 2013
CO_2 producing well, Dakota	1985/30 years old/Class G and fly ash at ratio of 1:1	N/A	0.3E-03 – 32E-03 / 2.5E-07 – 2.7E-05	19% – 45%	Shale	1E-06 – 10E-06 / 8.3E-10 – 8.3E-09	18% to 29%	0.8 – 3 / 6.7E-04 – 2.5E-03 (VIT)[1]	Gasda et al. 2011; Crow et al. 2010; Carey et al. 2010

								(single phase permeability	
Well 49-6, Permian Basin, West Texas	1960/55 year old well with 30 years CO_2 exposure/ Portland cement	N/A	0.09 / 7.5E-05 (intact cement, air perm.) or 0.23 / 1.9E-04 (heavily carbonated cement, air perm.)	33.5%	Shale/Limestone	N/A	1.3%/2.2%	N/A	Carey et al. 2007
Well 23, oil well, USA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.358 / 3.0E-04 (SCP)[2] (gas permeability)	Rocha-Valadez et al. 2014
Well 24, oil well, USA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.94 / 7.8E-04 (SCP)[2] (gas permeability)	Rocha-Valadez et al. 2014
Case 1, gas well, USA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	147.8 / 1.2E-01 (SCP)[2] (gas permeability)	Rocha-Valadez et al. 2014
Case 2, gas well, USA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4.01 / 3.3E-03 (SCP)[2] (gas permeability)	Rocha-Valadez et al. 2014
Case 3, gas well, USA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0114 / 9.5E-06 (SCP)[2] (gas permeability)	Rocha-Valadez et al. 2014

[1] tested using vertical interference tests (VIT)

[2] tested using sustained casing pressure (SCP)

[3] This range does not include the extreme permeability outlier for this bore of 4.63 mD (3.9E-03 m/d)

[4] This range does not include the extreme permeability outlier for this bore of 0.449 mD (3.7E-04 m/d)

Table 4.2 Cement types used in well construction. After Robertson et al. (1989).

Cement Class	**Indicative well depth (m)**	**Sulfate resistance**	**Early strength**	**Purpose**
A	0-1800	Ordinary	-	Special properties not required
B	0-1800	Moderate to high resistance types available	-	Low temperature and pressure, moderate to high sulfate resistance
C	0-1800	Ordinary, moderate and high resistance available	Yes	Low temperature and pressure, ordinary, moderate or high sulfate resistance available, used where early strength is required.
D	1800-3000	Moderate to high resistance types available	-	Moderately high temperatures and pressures
E	3000-4300	Moderate to high resistance types available	-	High temperatures and pressures
F	3000-4900	Moderate to high resistance types available	-	Extremely high temperatures and pressures
G	0-2400	Moderate to high resistance types available	-	Used with accelerators and retarders to cover a wide range of well depths and temperatures
H	0-2400	Moderate to high resistance types available	-	Used with accelerators and retarders to cover a wide range of well depths and temperatures
J	3700-4900	Moderate to high resistance types available	-	Extremely high temperatures and pressures, or can be mixed with accelerators and retarders

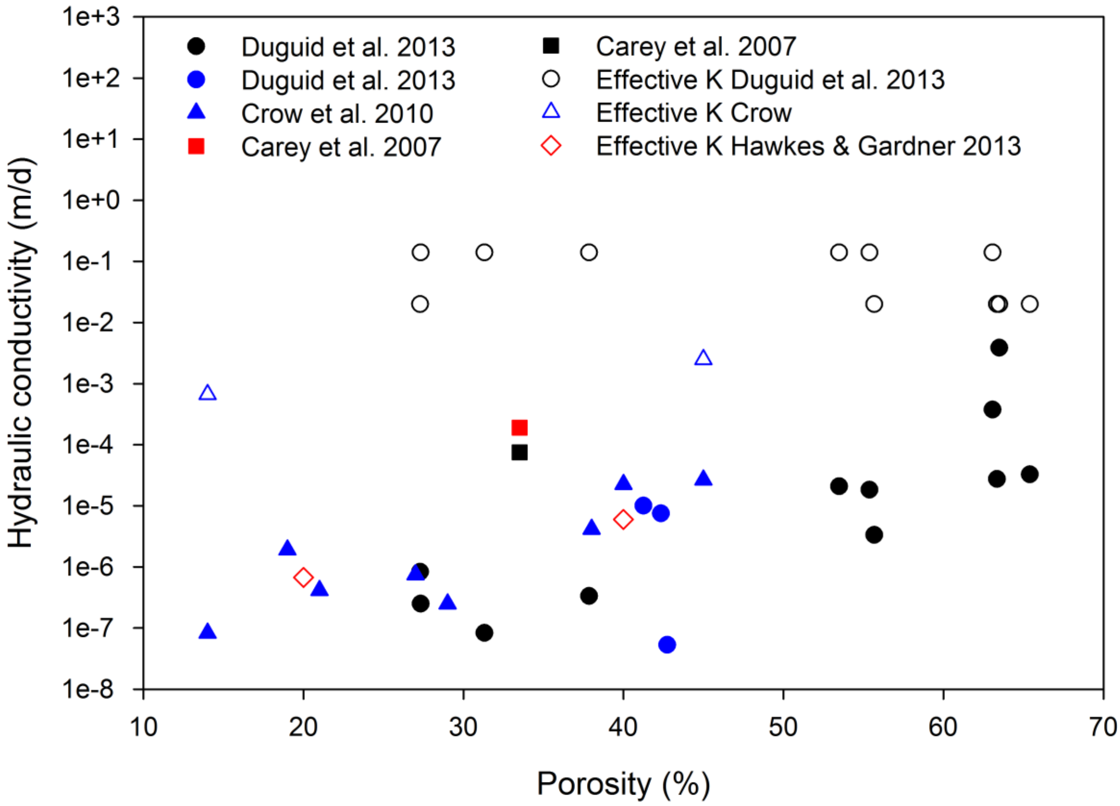

Figure 4.13 Relationship between cement core porosity and hydraulic conductivity, and where provided, effective well conductivity, based on data from Table 4.1. Each study is indicated by a different symbol, cement conductivity is shown as solid symbols, effective well conductivity is shown as open symbols, and the age of the well is indicated by the colour of the symbol: < 20 years – black; 20-40 years – blue; > 40 years – red.

4.2 Prioritising modelling efforts

To prioritise modelling efforts of potential impacts of individual wells, the well failure mechanisms described in Chapter 2 were collated into a risk assessment table in order to consider the likelihood of failure, detection of the failure, likelihood of repair and potential impact on hydrogeology (Table 4.6). This was used to assess the relative impact of each failure pathway and prioritise the importance for modelling.

The risk analysis framework was based on that used for the Australian Government Bioregional Assessments (BA) programme, and used a risk priority number based on the sum of scores for the severity, likelihood and detection of a failure type (Ford et al. 2015).

$$\text{Risk Priority Number (RPN)} = \text{Severity} + \text{Likelihood} + \text{Detection} \quad (1)$$

Severity, likelihood and detection scores previously reported by Ford et al. (2015) are given in Table 4.3 to Table 4.5. These scores are applied to the failure mechanisms discussed in Chapter 2.

In addition to these risk scores, a likelihood of repair has also been added to Table 4.6, with the same temporal definitions as the detection score in Table 4.5.

The Bioregional Assessments (BA) risk scoring system was developed to evaluate the cumulative impacts of coal operations (mining and coal seam gas) on water related assets. This project is concerned with the cumulative impacts from leaky coal seam gas wells on hydrogeology, therefore in theory the BA risk framework is transferrable for our purpose, with some minor modifications.

Table 4.3 Pre-designed environmental consequence (severity) levels and their corresponding scores (Ford et al. 2015). The positive 3 score for no impact is intended to balance the negative score for rare likelihood (log of the frequency of occurrence). Note that the description of impact on the environment for 'tiny', 'minimal' and 'minor' has been changed from contained 'within mining lease' to contained 'close to well'.

Impact Level	Environment	Score
None	No impact	3
Tiny	Minimal impact on ecosystem; contained close to well, reversible in 1 year	4
Minimal	Moderate impact on ecosystem; contained close to well, reversible in 1-5 years	5
Minor	Moderate impact on ecosystem; contained close to well, reversible in 5-10 years	6
Moderate	Significant impact on ecosystem; impact at level of exploration lease, reversible in around 10 years	7
Major	Significant harm or irreversible impact (for example to World Heritage area), widespread, catchment area, long term: > 10 years	8
Catastrophic	Incident(s) due to unforeseen circumstances causing significant harm or irreversible impacts (for example to World Heritage area); widespread, long term	9

Table 4.4 Likelihood score: log(frequency of occurrence per year). Likelihood, indicative recurrence and associated likelihood score (Ford et al. 2015).

Likelihood	Indicative recurrence	Likelihood score: log (frequency)
Extremely rare	One event in 1000 years	-3
Very rare	One event in 333 years	-2.5
Rare	One event in 100 years	-2
Very unlikely	One event in 33 years	-1.5
Unlikely	One event in 10 years	-1
Possible	One event in 3 years	-0.5
Likely	One event in 1 years	0
Almost certain	Three events in 1 year	0.5
Most certain	Ten events in 1 year	1
Frequently	33 events in 1 year	1.5
Very frequently	100 events in 1 year	2
Every day	365 events in 1 year	2.5

Table 4.5 Detection score. Detection, indicative days to detect and associated detection score (Ford et al. 2015).

Detection	Indicative days to detect	Detection score
Almost impossible	33333 days	4.5
Extremely hard	10000 days	4
Very hard	3333 days	3.5
Hard	1000 days	3
Quite hard	333 days	2.5
Easy	100 days	2
Quite easy	33 days	1.5
Very easy	10 days	1
Almost same day	3 days	0.5
Same day	1 day (within 24 hours)	0
Less than a day	0.3 of a day (< 8 hours)	-0.5

The risk analysis undertaken here is at a cumulative regional scale, rather than for an individual well. Analysis for each type of failure is set to be for the duration of each phase of a well's life cycle – drilling, cementing, hydraulic fracturing, production and decommissioning. The assumed lifespan of a CSG operation is approximately 25 to 30 years as per the Narrabri region (CDM Smith 2014). The latter report suggests an average recovery duration for the target production seam across the whole development is approximately 100 years, as per the changes in flow rates between the early Permian targets (Maules Creek Formation) and water bearing aquifers of the Narrabri region (CDM Smith 2014). Further investigation of the model outputs based on hydraulic head, rather than flow rates, suggest that the recovery duration at individual points where drawdown is highest, is likely to be of the order of 1000 years (Figure 4.10 and Figure 4.12). An estimate of 500 years for the head-based recovery duration is representative of the region.

One disadvantage of this risk assessment is the specification of risk of occurrence in abandoned wells, particularly the timeframe over which an assessment is taken. Risk of occurrence of failures in the Bioregional Assessment is averaged over the operational duration of the coal mine, whereas the likelihood of wells failing is dependent on the duration of the assessment period of interest. Within the operational phase, there may be one event every year to three years. For a timeframe of several hundred years, information from Alberta, Canada suggests that approximately 10% of wells will have compromised integrity (Section 3.2). Another analysis of Canadian data suggested that 4.6% of wells installed after around 1950 have compromised integrity. More recently installed wells should have a longer lifespan than the older wells included in failure assessments, mainly because of more stringent regulatory requirements regarding well design and construction.

As an example, for a CSG field with 750 CSG wells, such as the Bowen Basin, Queensland, and an assumed 100 year post-production assessment period with 10% failure after 100 years, this would yield 10% x 750 wells / 100 years, or just under one failure per year (Table 4.6). An important limitation to this assessment is that the expected lifespan of a decommissioned CSG well in Australia has not been accurately determined.

In the above case, the overall risk is also dependent on the number of wells in a CSG production area. As hydrogeological risk is dependent on the density of leaky wells within an aquifer (Turnadge et al. 2015), there is a strong basis to normalise the risk assessment to an areal unit of development, for example, the number of well failures per year per square kilometre. For this preliminary assessment, we will assume one well failure per year for Table 4.6.

This study was designed to assess the impact of well failure on hydrogeology only, and the risk framework was not designed to take into account any impacts on human health. Modification to the classification of impact level (Table 4.3) will be required if human health impacts were to be included. Additional assessment of the impacts of well failure on human health would require more specialised modelling.

Due to the low likelihood of detection and repair, the risk of failure in decommissioned and abandoned wells is likely to have the highest impact on the hydrological system. The calculated risk failure number is the overall highest (RPN = 8) among all mechanisms evaluated. Failure pathways in decommissioned wells should therefore be prioritised for further investigations through modelling (Table 4.6).

The conceptualisation for modelling well and bore failure types discussed in this report is outlined in the following sections. Possible mathematical expressions suitable for implementation in numerical models and existing and commonly used groundwater flow simulation software are discussed.

Table 4.6 Risk assessment of various methods of well/bore failure during or as a consequence of drilling, cementing, production and abandonment. Impact on hydrology (consequences) will be estimated through the hydrological modelling.

Failure type	Likelihood score	Detection score	Repair score	Risk priority number	Comments
Drilling					
Formation fluid influx or blowout	0	-0.5	1	0.5	Insufficient mud pressure or unexpected high formation pressure during drilling, or unexpected gas accumulation in capped well due to gas migration
Drilling fluid loss into formations	0	-0.5	1	0.5	Fractured formations or un-intentional formation fracturing
Cementing					
Cement bond failure	1	0.5	1	1.5	Poor mud displacement/hole condition/casing centralisation, well life stress/pressure changes
Cement slurry loss into formations	1	0.5	1	1.5	Fractured formations
Insufficient cement height	1	0.5	1	1.5	Poor hole condition/cement slurry loss
Production					
Hydraulic fracturing fluid loss into aquifer	0	-0.5	1	0.5	Coal seams is within aquifer
Creation of fracture pathways	0	-0.5	1	0.5	Cyclic stress/pressure on production casing
Shear damage in overburden	-1	-0.5	2.5	1	Reservoir depressurisation induced geomechanical effect
Decommissioning					
Microannulus on the interfaces	0	3.5	3.5	7	Poor mud displacement/hole condition/casing centralisation, well life stress/pressure changes
Flow through cement sheath	0	3.5	3.5	7	Poor cement job, cement deterioration, cement sheath failure
Flow through cement plugs inside well	0	3.5	3.5	7	Poor cement job, cement deterioration
Flow through steel casing	0	3.5	3.5	7	Corrosive downhole environment

4.3 Groundwater flow pathways linked to well failure

Well failure is possible during or as a consequence of the design and/or construction, production, and abandonment phases of the CSG process (see Darrah et al. (2014) and Reagan et al. (2015) for examples from shale gas production). Four major pathways for movement of water between strata have been identified:

- Uncased exploration bores which are drilled and uncased, and on decommissioning are backfilled with the drilled rock material – design fault (Figure 4.14 and subsequent discussion in section 4.3.1)
- Decommissioned production wells which are wellbores with a steel well casing and cement sheath, which are cemented with cement plugs on decommissioning – design and/or construction, production or abandonment fault (Figure 4.15 and subsequent discussion in section 4.3.2)
- Oil and gas wells repurposed for water extraction and water bores in which casing has corroded and/or there is no cementing of the annulus – design and/or construction fault (Figure 4.16 and subsequent discussion in section 4.3.3), and
- Fractures and faults between wellbores and surficial aquifers – natural feature (or design i.e. locational fault) (Figure 4.17 and subsequent discussion in section 4.3.4).

All of the above pathways specifically relate to flow of water, where water includes dissolved ions, gases, etc. In addition to being pathways for water, they may also be pathways for gaseous compounds, mainly methane, in their free gas phase. Free gases move from high potential energy to low potential energy when a continuous gas phase is present, otherwise gases may rise upwards depending on the relative strength of the capillarity forces versus the buoyancy forces in water (Iglauer et al. 2011, 2015). The capillary forces are acting to prevent the entry of the nonwetting phase (here the gas phase) in the reservoir or aquifer rock, and are in competition with upward buoyancy forces (a free hydrocarbon phase rises in a water column because its density is less than that of water). Especially the latter process may be important for transporting free gas between strata. Because the focus of this study was primarily on groundwater flow, the subsequent discussions will relate primarily to groundwater flow. Note, however, that the conceptualisations discussed can also be used to inform multi-phase modelling with explicit consideration of a free gas phase (Cartland et al. 2004).

Each of the above pathways for movement of water between strata have been discussed in detail in sections 4.3.1 to 4.3.4. This includes conceptualisation of how to represent each of the key processes in groundwater models used to determine the impact of individual failed wells and the cumulative effect of multiple failed wells within a CSG production area. The subsequent sections 4.3.5 to 4.3.6 discuss the well failure processes and events that can occur during or as a consequence of well construction or gas production. Section 4.3.7 describes how such pathways can be conceptualised for use in a single phase groundwater model. Finally, based on evidence from US studies (US EPA 2015) and compliance auditing in Queensland (see discussion in section 3.7 based on data from GasFields Commission 2015), these are not considered to be major pathways.

4.3.1 Pathways linked to exploration bores

In Queensland, coal exploration bores are the most significant legacy type, mainly due to their abundance and possible lack of appropriate decommissioning, both of which is at this stage unquantified. It has been estimated some 30,000 coal exploration bores have been drilled in the Surat Basin, with another 100,000 in the Bowen Basin (Free 2013, pers. comm., 28 February 2014). It is unknown however how many of these bores were decommissioned or, if they were decommissioned, the standard of the decommissioning work (Commonwealth of Australia 2014a).

Decommissioning the coal mining exploration wells is regulated by the *Code of Environmental Compliance for Exploration and Mineral Developments* in Queensland (DEHP 2013), which set out the following requirements:

'The holder of the environmental authority must decommission all non-artesian drill holes, apart from those still required for monitoring purposes as soon as practical, but no later than 6 months after the hole was drilled by undertaking the following actions:

- where practical dispose of all unused drill chips to the hole or to a sump pit and;
- cap the hole at a depth that is appropriate for the previous land use of the area (unless the land owner stipulates a future use which requires the cap to be placed deeper); and
- backfill the hole above the cap with soil or material similar to the surrounding soil or material'.

Coal exploration bores decommissioned under these requirements may therefore lack an adequate appropriate seal (i.e. cement plug) and could be considered as legacy bores. Furthermore, despite the above regulations that specify the decommissioning process, it is difficult to determine the level of compliance in remote areas (Commonwealth of Australia 2014a).

For uncased bores, possible groundwater pathways include (Figure 4.14):

- Flow of water through the uncased bore hole from production interval to water bearing surficial aquifers, when the gradient is from the coal formation towards the aquifer (1) (in the case of an artesian coal seam layer, not impacted by depressurisation); the flow is from the aquifer towards the coal formation in the case of a downward gradient (2) (typically during the CSG extraction depressurisation phase, see e.g. Figure 4.9 and Figure 4.11)
- Flow of water through the backfilled, uncased bore after decommissioning; as with the previous pathway, flow can be upwards (3) or downwards (4), depending on the hydraulic gradient (see e.g. Figure 4.6).

Movement of water between the production target and surficial aquifers is possible through the backfilled bore (Figure 4.14). Due to the drilling disturbance, the hydraulic conductivity will be considerably higher through the backfilled hole than the surrounding soil and rock matrix. The maximum flow of water between formations through the exploratory wells decommissioned this way may be estimated using equations for Darcy flow through a conduit (Appendix 1), with the length equal to the depth of the exploration bore, hydraulic conductivity for a disturbed soil sample (or no soil), and a head gradient calculated from the difference in pressure head between the production formation and the surficial aquifer. Comparison of the flow through a decommissioned exploration bore and the regional aquitards may give a critical density of bores required to significantly exceed the flow rate through the regional aquitards.

Drilling fluid loss to the surficial aquifers and well breakout are also possible for exploration bores. These processes are discussed in more detail in section 4.3.5.

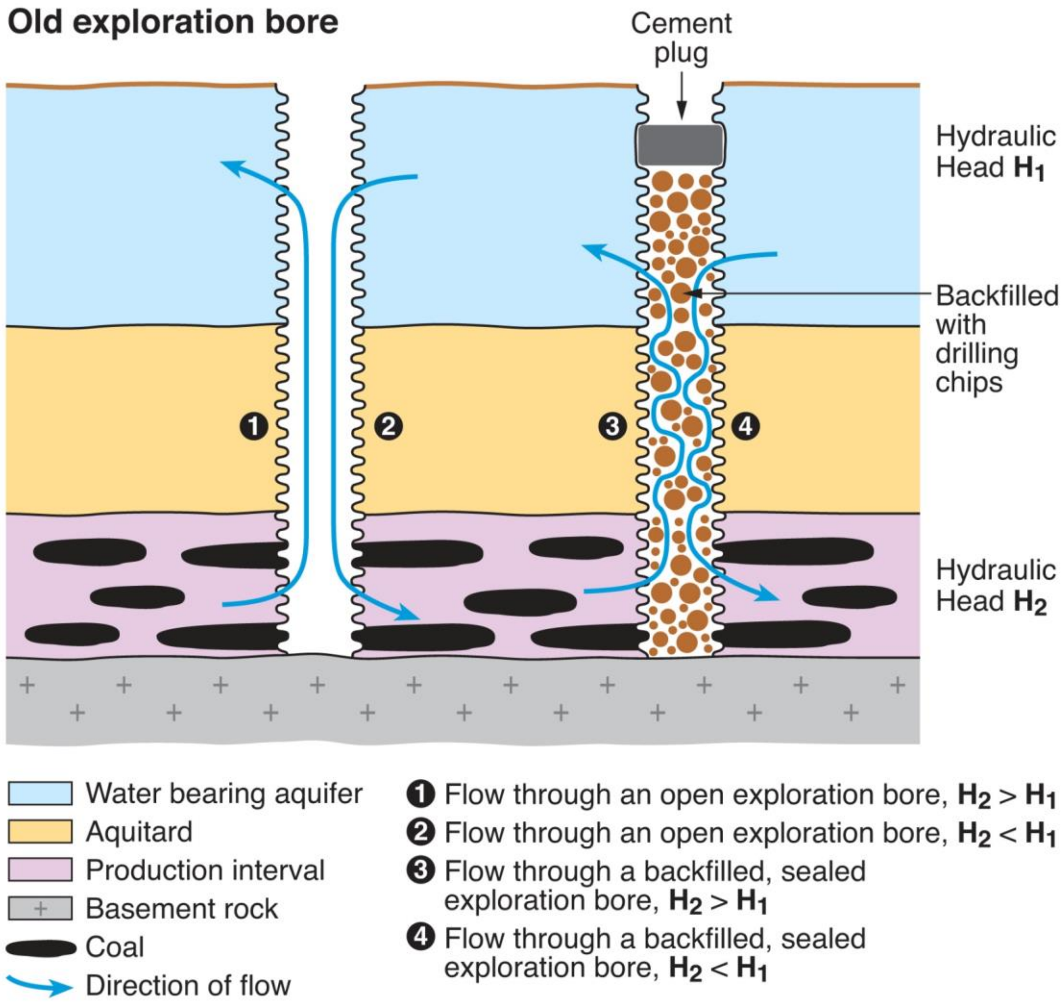

Figure 4.14 Pathways for water movement in uncased exploration bores: (1) upward flow through an open exploration bore (H_2>H_1), (2) downward flow through an open exploration bore (H_1>H_2), (3) upward flow through an initially backfilled exploration bore whose sealing capacity has been impaired (H_2>H_1), and (4) flow through a backfilled, sealed exploration bore (H_1>H_2).

4.3.2 Pathways linked to decommissioned and abandoned wells

In decommissioned and abandoned wells, loss of integrity may lead to the following pathways for water migration (Figure 4.15):

- through a micro-annulus between the cement casing and the soil/rock matrix (1) or the steel well casing (2)
- through a deteriorated cement sheath between the well casing and soil/rock matrix (3)
- through deteriorated cement plugs used in decommissioning (4, 5), and
- through the well itself, via corrosion holes, shear or tensile damage (6).

Potential flow pathways can be summarised as annulus flow between the steel casing and cement and/or rock matrix, flow through cement plugs or cement annulus, and flow through the corroded or sheared, steel casing or tubing (see for decommissioned and abandoned wells). Pathways for water movement through an oil and gas well repurposed for water extraction are shown in Figure 4.16.

In Figure 4.15 flow is from upper aquifer to lower aquifer based on the downward head gradient ($H_1 > H_2$). This scenario represents the period of depressurisation during or long after gas extraction has ended (note from Figure 4.8 that recovery to the initial hydraulic head condition in the coal seam formation may take hundreds of years). When an upward gradient exists ($H_2 > H_1$), flow will be from the lower to the upper aquifer. The latter condition was observed both pre-CSG and post-CSG extraction in several locations of the groundwater model discussed in section 4.1.2 (Figure 4.4).

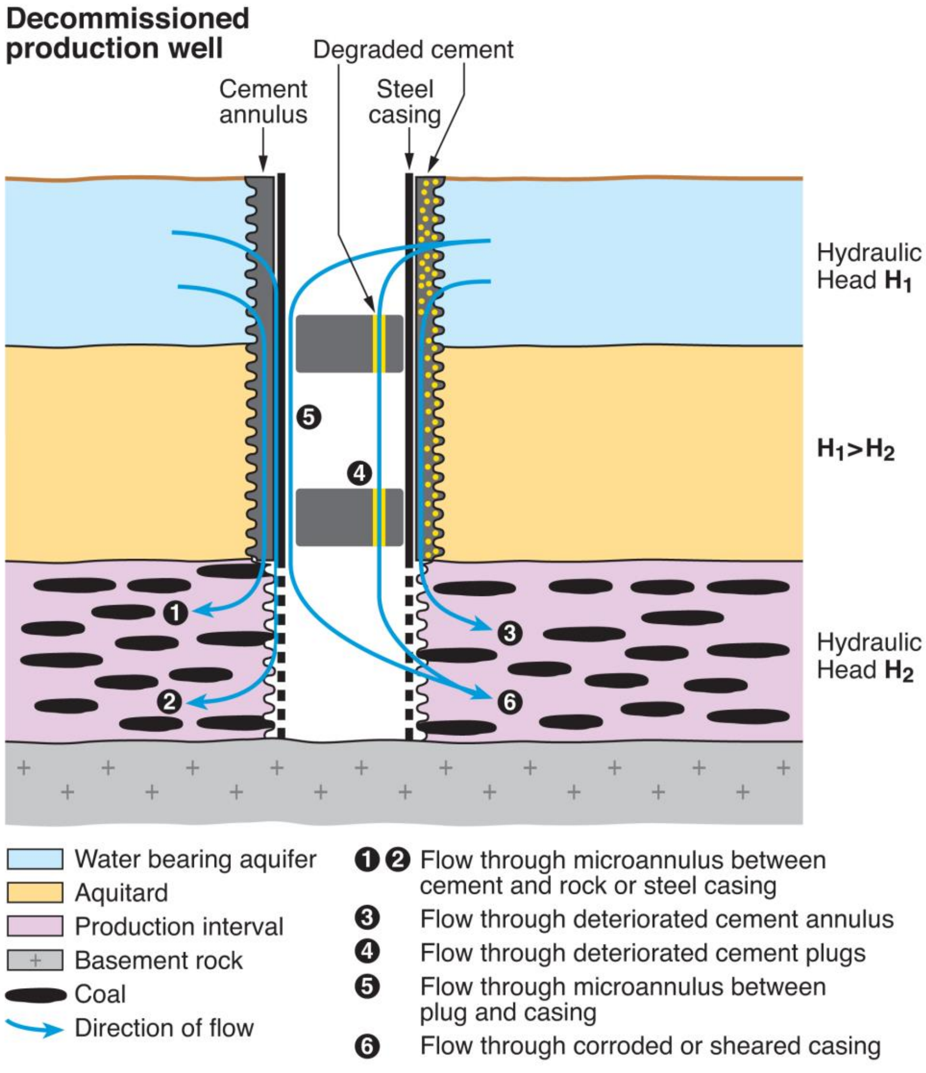

Figure 4.15 Pathways for water movement in cemented wellbores: flow through microannulus between cement and rock matrix (1) or steel casing (2), flow through deteriorated cemented annulus (3), flow through deteriorated cement plugs (4), flow through microannulus between plug and casing (5), and flow through corroded or sheared casing (6). Upward flow is equally possible when $H_2 > H_1$.

4.3.2.1 Flow through microannulus on the interfaces

Flow is through a thin annulus between the cement and surrounding rock matrix, or cement and steel casing, so the fluid will experience friction against the sides of the cement and rock matrix rather than the resistance experienced by flow through a porous media, typically represented by Darcy's law. Usually these interface annuli are small, and flow rates are low, but where cementing is incomplete due to bore hole collapse or washout or insufficient cement height, the annulus is larger and flow rates may be large enough to warrant modelling for quantification.

This type of flow is best represented by algorithms for flow through conduits. The width of the conduit is defined as the circumference around the well cement, the length of the conduit is the vertical length of the gap or the distance between the production reservoir and the surficial aquifers, and the aperture is the average width of the gap between the cement and the rock matrix. Equations for the hydraulic properties of an annulus are given in Appendix 1.

Flow between the internal cement plug and steel casing has a similar conceptualisation, but with the well divided into nodes representing each of the cement plugs and open pipe sections.

For flow between the internal cement plug and steel casing, the effective hydraulic conductivity would be defined with the flow length parameter (see Equation 3, l_{cn} and l_{cm}) equal to the vertical dimension of the cement plug.

4.3.2.2 Flow through degraded cement sheath

This conceptualisation is similar to the work by Nowamooz et al. (2015), with flow through porous media (degraded cement) within the well annulus. The effective well hydraulic conductivities are likely to range between 10^{-6} and 10^{-1} m/d as indicated in Table 4.1. Nowamooz et al. (2015) suggest that this is one of the most common types of failure.

4.3.2.3 Flow through degraded cement plug

Flow through a degraded cement plug is also described in Nowamooz et al. (2015). Effective hydraulic conductivity may be calculated from the effective cement conductivities suggested in Table 4.1 (approximately 10^{-6} to 10^{-1} m/d).

4.3.2.4 Flow through corroded steel casing

Flow will be dependent on the size and location of the corrosion hole in the steel casing and on the nature of pathways through the degraded or incomplete cement annulus. The maximum impact will be when the hole is big enough not to limit the flow vertically through the well. A number of scenarios may be modelled, including a number of different degrees of flow-limiting hole sizes. Flow through the steel casing also requires cement plugs to be degraded or not present.

4.3.3 Pathways linked to water bores and repurposed oil and gas wells

The assessment of the integrity of water bores in the Surat Basin, Queensland, revealed that a large number of bores (about 3500) constructed prior to 1968 are assumed to have poor integrity (Section 3.6). The assumption is that the less stringent regulations regarding bore construction before 1968 resulted in a less engineered and thus less protective environment for a bore's steel casing. As result, the steel casing would have corroded significantly by now. This would potentially provide leakage pathways that could increase the inter-aquifer connectivity.

Seepage flow pathways may also exist within oil and gas wells repurposed into water extraction bores, especially when casing has been removed and there is no cementing of the annulus (Figure 4.16). Potential pathways include (for examples, see DNRM 2013c):

- Flow of water from unstressed, alluvial aquifers to stressed, confined aquifers (1),
- Flow from artesian aquifer to alluvial aquifers (2), and
- Mixing of water pumped from both alluvial and confined aquifers (3).

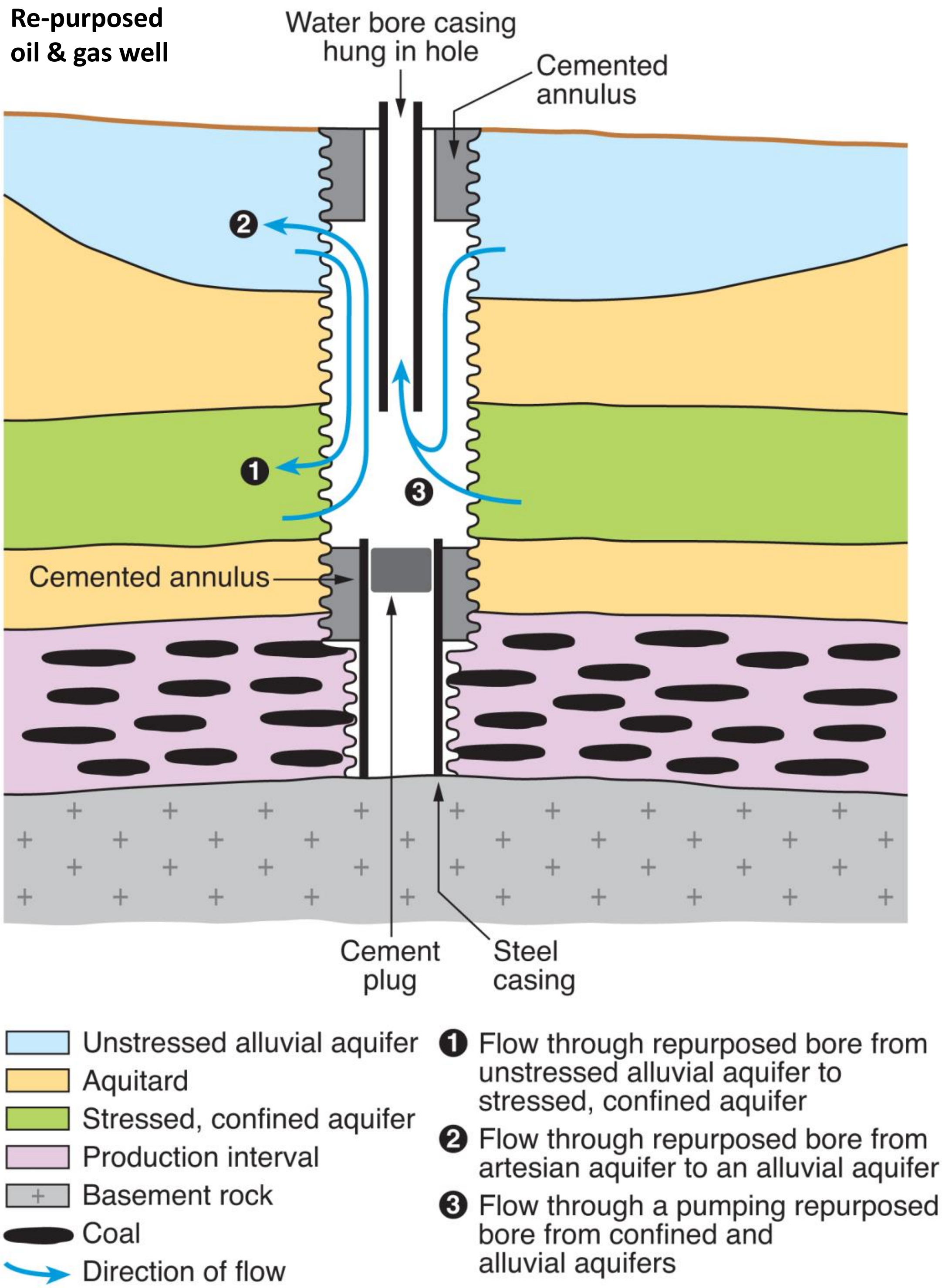

Figure 4.16 Pathways for water movement through an oil and gas well repurposed for water extraction: (1) flow through a repurposed bore from the unstressed, alluvial aquifer to a stressed, confined aquifer, (2) flow through a repurposed bore from an artesian aquifer to an alluvial aquifer and (3) mixing of water through pumping from both confined and alluvial aquifers.

4.3.4 Pathways linked to natural rock fractures and faults

Flow through permeable natural rock fractures may also be modelled for production wells by characterising a fracture network or fault and applying the high head gradients from hydraulic fracturing across the fracture or fault (see Figure 4.17). An additional model run with background hydrostatic pressures, rather than pressurised hydraulic fracturing fluid, should also be considered to compare the rate of water transmission during hydraulic fracturing with the flow of water naturally found through rock fractures where CSG production is not present.

Preferential pathways through fractures and faults (Figure 4.17) include:

- Flow of water through pre-existing permeable fractures (1),
- Flow of water through existing permeable faults (2), and
- Flow of water through fracture pathways created by hydraulic fracturing (3).

Similar to Figure 4.15, groundwater flow may be from lower to upper aquifer where the head gradient (H_2>H_1) is upward.

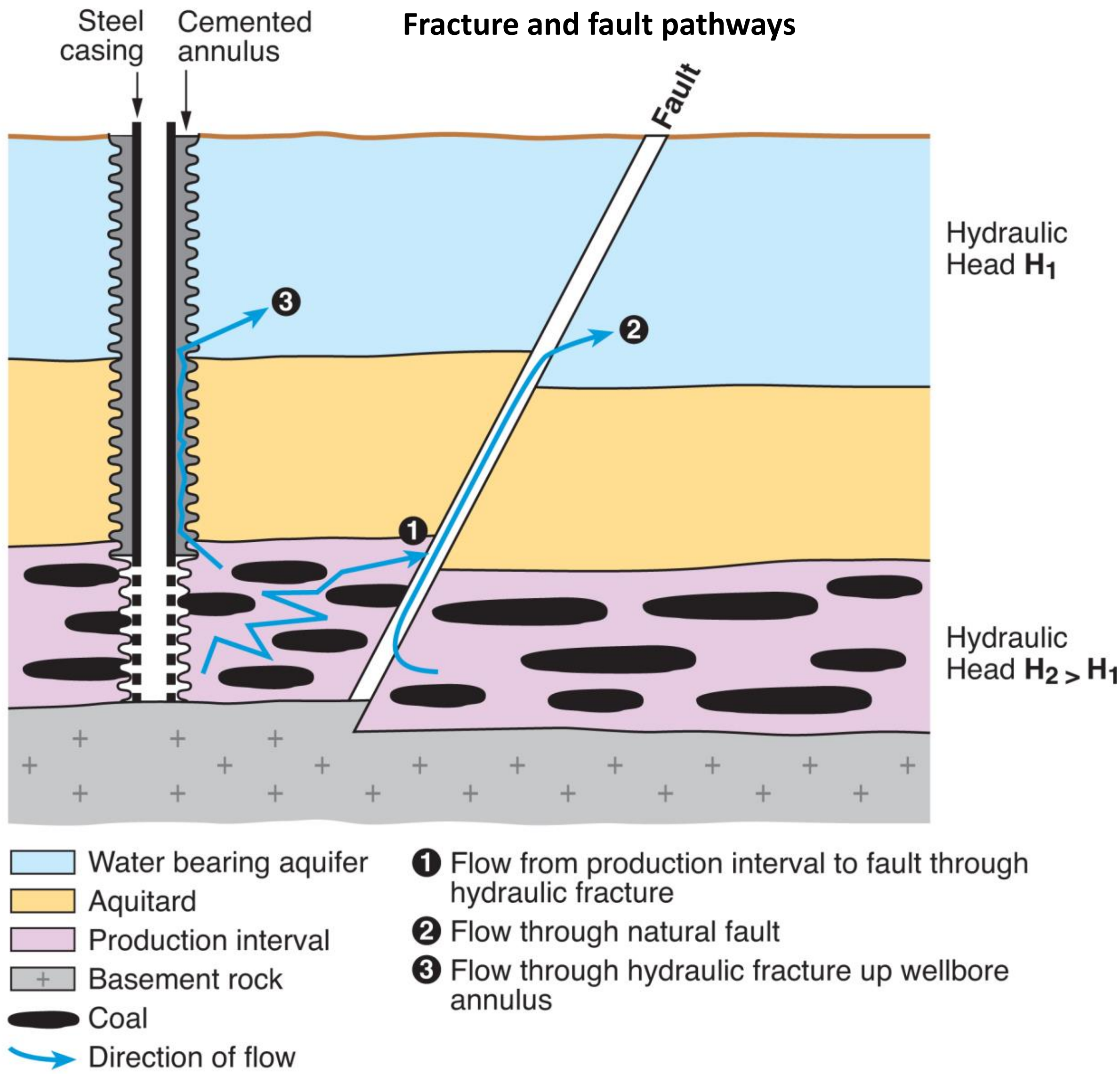

Figure 4.17 Pathways for water movement in fractures and faults during hydraulic fracturing events: (1) flow from production interval through fractures, (2) flow through a natural fault, and (3) flow through a hydraulic fracture up the wellbore annulus. Downward flow is equally possible when H_1> H_2. Note: This is a simplified fault representation; any flow associated with the fault plane is likely to involve flow through connected fractures in the damage zone either side of the fault.

4.3.5 Well failure linked to CSG well construction phase

Well failure as a consequence of construction is usually a result of drilling fluid losses during the drilling process and incomplete or poor quality cementing of the wells.

4.3.5.1 Formation fluid influx or blowout

When the formation fluid pressure is significantly higher than the pressure of the drilling fluid in the well, formation fluid influx or blowout can occur. Because its effects (i.e. consequences) will likely be short-term and near-well, the blowout does not represent an immediate risk of contamination. Rock failure on the borehole wall in the forms of breakouts or washouts can also occur due to insufficient drilling fluid pressure. This can be minor, such as small pieces of rock breaking off from the walls of the borehole, or major failures where some of the failed rock materials cannot be removed from the borehole by the drilling fluid. The result is large variations in well diameter and a poorly cleaned hole, which have the potential for insufficient and poor cementing.

The hydrogeological impact of the borehole breakouts/washouts may be conceptualised as flow through the well annulus due to insufficient cementing. This is most likely to be a more significant issue after well decommissioning or abandoning, and is outlined in more detail in Section 4.3.2.

4.3.5.2 Drilling fluid loss

It is also important to consider the impacts of drilling fluid loss into aquifers. While there is little data reported on the possible volume of drilling fluid loss for CSG wells, for conventional oil and gas wells, this volume can range from hundreds to several thousands of barrels (12 to over 120 m^3) for carbonate formations (Wang et al. 2010).

Determining the hydrogeological impact in terms of aquifer contamination would involve modelling the release of a volume of drilling fluid into the aquifer used for water extraction. Modelling the transport of solutes within the drilling fluid within the aquifer is advisable to determine the extent and duration of hydrogeological impact.

4.3.5.3 Cementing

Poor cementing of wells can result in insufficient cement height, and poor quality cement sheath and cement bonds, which is likely to deteriorate with time and allow flow of water between different geological units through the well annulus. Poor quality cement may be the result of too rapid curing (high heat release), incorrect pressure or temperature ratings for the depth of well in which it is used, incorrect level of sulfate resistance and use of inappropriate additives. The conceptualisation of flow through decommissioned bores is discussed in Section 4.3.2.

4.3.6 Well failure linked to production phase

Well failure during or as a consequence of production is likely to be a result of geomechanical impact to the well above, within or below the production interval due to compaction or expansion of the rock formations surrounding the well. During hydraulic fracturing there is a risk of losing hydraulic fracturing fluids into the surficial aquifers via one or a combination of the following fluid flow pathways connecting the production zone and surficial aquifers; i) newly created fractures, ii) existing or mobilised permeable faults, and iii) uncemented or poorly cemented well annulus (Reagan et al. 2015).

4.3.6.1 Shear failure of well in overburden formations

The maximum possible impact for wells that are damaged by shear movement of the formations above the production interval (e.g. Figure 2.5) is that flow is possible between the production zone and surficial aquifers through the entire well conduit. The direction of flow will depend on the hydraulic head gradient between the production zone and aquifer. This may be modelled using groundwater flow equations through the bore using a maximum conductance calculated for flow through the well casing. Due to the large head differences between the aquifers and production interval during production, the rate of flow through the well is likely to be high, which may warrant using equations for turbulent flow (see discussion in Section 4.3.7).

4.3.6.2 Hydraulic fracturing liquid losses into the aquifer.

For hydraulic fracturing of CSG wells, the typical volume of hydraulic fluid per operation in Australian coal seams is approximately 1 ML per well (with a range from 0.15 to 1.5 ML). In the case of release of hydraulic fracturing liquids during fracturing, involving pathways via an uncemented or poorly cemented well annulus or via existing or mobilised permeable faults, flow during the fracturing event is most likely going to be from the production zone into adjacent aquifers used for water production. See also Section 4.3.6.3.

4.3.6.3 Creation of fracture pathways between the production and surficial aquifers

Fracture pathways in the overburden and aquitards may be created through the process of hydraulic fracturing, i.e. pressurising the coal seams within the production reservoir in order to create access for subsequent gas extraction. Because the hydraulic fracturing operations are highly engineered, optimised and monitored, the likelihood for fractures growing vertically within and through aquitards is very unlikely.

This type of failure may be modelled by creating typical fracture pathways in the rock matrix and estimating flow through the fractures under both high pressure during the hydraulic fracturing process, or low pressure during production and once the well is abandoned.

4.3.7 Pathway conceptualisation for groundwater modelling

Consider a CSG target formation whose hydraulic head exceeds that of the overlying water bearing aquifer. In the case where a preferential flow path exists due to a leaky well, upward flow between the CSG formation and the aquifer may be modelled using a Darcy flow conceptualisation:

$$Q = KA\frac{dh}{dl} \qquad (2)$$

where K is the effective hydraulic conductivity (averaged over all components contributing to the flow path – possibly including the well, the cement annulus or the microannulus, etc.), A is the cross sectional area of the well, the cement annulus or the microannulus between the cement and rock matrix or steel conduit, dh is the head difference between the water entry and exit points from the well or annulus, *and* dl is the length of the flow path between the points at which dh is measured.

A simplified conceptual representation of a possible flow condition is provided in Figure 4.18. Here, dh is the head difference between h_1 and h_2, dl is length of the well l, and the cross-sectional flow area is a function of the radius of the well r (assuming flow is through the well).

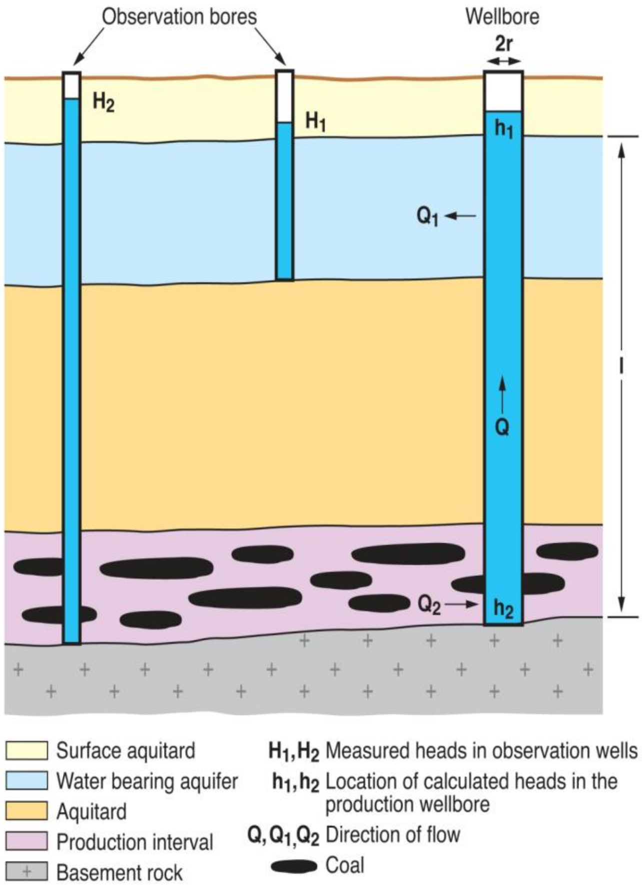

Figure 4.18 Conceptualisation of flow through a failed well in the case of an artesian CSG target formation. Q is the flow through the bore, l is the length of the bore, r is the radius of the bore, h_1 *is the pressure head in the upper aquifer within the well,* h_2 *is the pressure head in the lower aquifer within the well, and* H_{o1} *and* H_{o2} *are head measurements in observation bores in the upper and lower aquifers, respectively.*

Depending on the cross sectional flow area, the effective hydraulic conductivity and the pressure head difference, flow within the bore may be laminar[3] or turbulent (Figure 4.19). For leaky wells with flow along the degraded cement annulus or well centre, the effective permeability was found to be in the 10^{-11} to 10^{-6} $m.s^{-1}$ range (see Table 4.1 and Figure 4.13). Comparing the latter values with the range of conductivities used in Figure 4.19, one can conclude that turbulent flow is very unlikely to occur in wells with degraded cement. Turbulent flow, which may occur in preferential pathways present in sealed exploration bores, may require alternative formulations within the well, i.e. the Darcy-Weisbach equation (Brown 2002), the Hazen-Williams equation (Williams and Hazen 1933; Liou 1998), or the Manning's equation (Kamand 1988). These equations are detailed in Appendix 1.

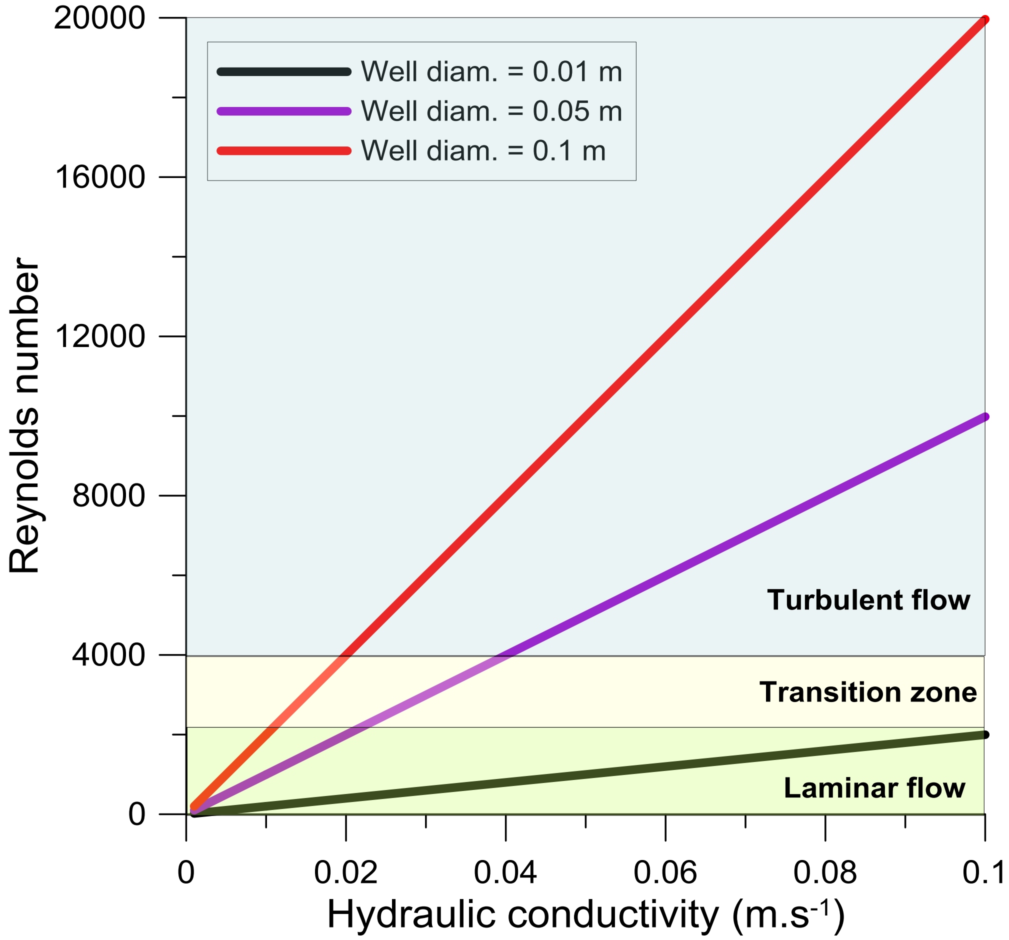

Figure 4.19 Dependency of Reynolds number on well hydraulic conductivity and well diameter. Hydraulic gradient is 2.

In addition to the conditions of the well, exchange of fluid between aquifers may be regulated by the ability of the production zone or surficial aquifers to release or accept quantities of water. A sensitivity analysis using analytical formulations for flow in a well has been undertaken to assess under which hydrogeological and well conditions preferential flow causes material changes to the head in the losing aquifer (Turnadge et al. 2015).

[3] Laminar flow in a pipe occurs when Reynolds number < 2100 and turbulent flow occurs when Reynolds number > 4000. For flow in a pipe, Reynolds number R_D is defined as $(QxD)/(vxA)$, where Q is volumetric flow rate ($m^2.s^{-1}$), D is diameter (m), v is kinematic viscosity ($m^2.s^{-1}$), and A is pipe cross-sectional area (m^2).

4.4 Appropriate models for well integrity failure analysis

There are a number of models that are potentially suitable for modelling the hydrological impacts of well failure. Models include single phase groundwater flow models such as MODFLOW (Harburgh 2005), FEFLOW (Diersch 1998; Diersch 2005) or HydroGeoSphere (Therrien et al. 2006) and multi-phase models such as ECLIPSE (Schlumberger 2011), TOUGH 2 (Pruess et al. 1999) or DuMu^x (Flemisch et al. 2011).

The most appropriate model to select depends significantly on the questions being asked: specifically the substance being modelled (liquid, solute or gas) and the location of interest: the production zone, surficial aquifers or the land surface. This must be decided at the outset of the project, as it is not a simple matter to change models during the course of the modelling.

4.4.1 Groundwater flow models

The benefits of groundwater flow models such as MODFLOW or FEFLOW are that they are readily available, commonly used by water resources managers and have the necessary pre and post processing facilities to develop highly complex hydrogeological conceptual models. This includes the ability to include wells and surface water flow if required. Often, the conceptualisation and parameterisation process for a region has already been undertaken by a water resources management organisation and data is readily available. The MODFLOW USG process (Panday et al. 2013) allows the use of an unstructured grid, and with the Connected Linear Network (CLN) package, passive flow through well and fractures can be modelled (Panday et al. 2013).

4.4.2 Multi-phase models

Multi-phase models such as ECLIPSE (Schlumberger 2011), TOUGH 2 (Pruess et al. 1999) or DuMu^x (Flemisch et al. 2011) allow water and gas, water and oil or water oil and gas phases to be modelled. They tend to be computationally intensive, however, and require additional resources to set up and run. The most complex models, such as ECLIPSE, can be prohibitively expensive for smaller projects. For questions that involve the transport of a gas phase, or hydrodynamics within the production interval (such as drawdown modelling), these codes have the required capabilities and are commonly applied in the oil and gas industry (Wang et al. 2012; Turnadge et al. 2015).

4.4.3 Model appropriateness

Using a single phase flow model typical in hydrogeological modelling such as MODFLOW, to simulate multi-phase flow features associated with well failure will impact results, although the extent to which this may occur has not yet been fully quantified. Moore et al. (2014) found that a single-phase MODFLOW 2005 (Harburgh 2005) model of the Walloon Coal Measures in the Surat Basin, Australia, led to overpredictions in drawdown from CSG wells compared with the otherwise equivalent two-phase ECLIPSE model (Schlumberger 2011). This was due to the inability of a single-phase model to simulate loss of water from the rock pore due to displacement by gas, and reduction in the relative permeability after desaturation of the coal seam. For a dual-phase flow system, typically in the near vicinity of the coal seam gas extraction areas, a simplified representation of the multi-phase process by a single-phase model may yield erroneous results, but on the conservative side in terms of drawdown prediction. Despite the lack of accuracy, the single-phase flow model may still be fit-for-purpose when regional scale screening of potential impacts of well integrity failure is being undertaken. More detailed assessments with a dual-phase model can then be undertaken to confirm or refute the degree of impact identified by the regional-scale single-phase model. Furthermore, regional-scale implementation of a dual-phase flow model across potentially hundreds or thousands of wells is computationally very demanding (Moore et al. 2014).

Although this project considers only the hydrological impacts of CSG well failure on surface or near surface water resources, that is, the movement of water (and potentially water borne contaminants) through the aquifer, the presence of gas in the system will still affect the rate of water movement. It is important, therefore, to test the effect of using a single-phase flow model on flow and transport. To quantify this effect, it would be worthwhile to replicate the conditions of the dual-phase Nowamooz et al. (2015) study using the single phase model MODFLOW USG. The results of this test may provide guidance as to whether the fine scale modelling needs to be undertaken with MODFLOW USG or a dual-phase model such as DuMu^x or TOUGH2.

4.4.4 MODFLOW USG conceptualisation

Flow from water bearing aquifers to the CSG production formation may be modelled using the Connected Linear Network package (CLN) within MODFLOW-USG (unstructured grid). The CLN package is able to represent flow through both wells and fractures (Panday et al. 2013). Both wells and fractures are represented by the fraction of volume of the CLN cell that is saturated, the cross sectional area of the CLN cells, the length of the CLN cells and the saturated linear conductivity of the connection between two CLN cells. Most of the failure pathways discussed in section 4.3 may be represented by this formulation by varying the saturated linear conductivity, the flow length and the cross sectional area.

The continuity equation for flow between CLN cells and from adjoining rock matrix cells is given by:

$$\frac{V_n f_{vn}}{\Delta t} = \sum_{m \in \eta_n} \frac{a_{cnm} K_{cnm} f_{unm} \left(h_n - h_m\right)}{0.5\left(l_{cn} + l_{cm}\right)} + \sum_{p \in \eta_n} \Gamma_{cpn} \tag{3}$$

where V_n is the total volume of cell *n* (L^3), f_{vn} is the fraction of the volume of CLN cell *n* that is saturated (-), *t* is the timestep over which the calculation is performed (T) f_{unm} is the fraction of upstream CLN cell volume that is saturated (-), a_{cnm} is the cross sectional area of the connection between the CLN cells (L^2), K_{cnm} is the saturated linear conductivity of the connection between the CLN cells *n* and *m* (LT^{-1}), h_n and h_m are the heads in cells *n* and *m* respectively (L), l_{cn} and l_{cm} are the length of CLN cells *n* and *m* (L), Γ_{cpn} is the volumetric flow from a connected GWF cell *p* to a CLN cell *n* (L^3T^{-1}) (Panday et al. 2013).

The CLN process in the advanced version of MODFLOW-USG can simulate water flow through a conduit in laminar or turbulent states. An upper bound estimate of flow through an abandoned (orphaned) well is conceptualised as flow through the full diameter of the bore through corrosion or damage in the steel casing, unlimited by the ability of the surficial aquifer or production formation to supply or dissipate water to or from the bore. In this case, flow through the well is likely to be turbulent, and the effective saturated linear conductivity (K_{cnm}) for the CLN can be estimated from the Darcy-Weisbach equation, using the Colebrook formulation for turbulent flow through rough conduits. Optionally, the Hazen-Williams equation or Manning's equation could also be used (see Appendix 1 for equations).

For lower head gradients or flow through degraded cement with a lower equivalent well hydraulic conductivity, flow through the well may be laminar. Laminar flow is computed using the Hagen- Poiseuille equation, while three formulations are provided to simulate turbulent flow – the Darcy-Weisbach equation, the Hazen-Williams equation, and the Manning's equation (Panday, pers comm.). Information for the total area of the conduit, the wetted area of conduit, the total perimeter and the wetted perimeter is required to use these formulations. Testing for turbulent or laminar flow by calculating the Reynolds number can be done simply for each case prior to analysis (see Section 1.1.1).

5 Identification of knowledge gaps

Water bore failure rate in Australia

There is very limited information in the public domain, and held by stakeholders, on the integrity of water bores in Australia (GHD 2010; Commonwealth of Australia 2013). There is even less information on the possible consequences of reported or assumed bore failure, and whether or not remediation is necessary.

CSG well failure rate in Australia

There are currently insufficient data/information available from open literature, government regulatory and industry bodies to establish well failure rates for CSG wells in Australia. This is mainly because the industry is relatively young, and not because of lack of monitoring and disclosure.

Well failure criteria and consequences of well failure

Currently well failure is vaguely defined as failure of all well barriers, with a leakage pathway being created across all well barriers (King and King 2013). Well failure may result from a well breach (or number of well breaches), and can take the form of a hydrological or environmental breach. However, there is currently a lack of understanding as to what is an acceptable minimum rate of fluid released from a well that will have a negligible impact on the environment. More studies are needed on the consequences of well failure with respect to potential environmental impacts.

Failure mechanisms – cement sheath/bond integrity under well-life stress and pressure conditions

A CSG production well is likely to be subject to cyclic pressure/stress during its life. The cyclic pressure/stress can be induced due to casing pressure tests, leak off tests and hydraulic fracturing stimulation. Little is known about the status of the cement sheath and cement bond integrity under the cyclic well stress/pressure over the entire well life.

Failure mechanisms – reservoir compaction induced casing and cement sheath failure

The impact of reservoir compaction on casing and cement sheath integrity is well established for conventional oil and gas wells. Coal seam compaction is expected due to depressurisation for highly fractured and compressible coal seams. Furthermore, coal seams will shrink as more coal seam gas is produced. A recent background review on subsidence from coal seam gas extraction in Australia indicated there is no confirmed surface subsidence; the maximum predicted potential subsidence is approximately 280 mm. This is a prediction of cumulative compaction of all strata subject to drawdown, while deformation was considered unlikely to be expressed at the surface owing to the bridge function performed by the shallower rock preventing downward movement. It is poorly understood if such compaction will affect casing, cement sheath and cement bond integrity for coal seam gas wells.

Cement durability and degradation rate under typical CSG well condition

Degradation of individual well barrier elements, such as cement and casing steel, have been studied in the laboratory by exposing them to an environment relevant to CO_2 geo-sequestration, which is considered to be a harsher environment than that encountered by a CSG well. However, there is a lack of data/information on cement durability and degradation rate under typical CSG well downhole conditions in Australia.

Effective well permeability

Although there are some US studies on the permeability of degraded cement in CSG wells (Duguid et al. 2013, 2014; Gasda et al. 2011; Crow et al. 2010; Carey et al. 2010; Carey et al. 2007), effective well permeability includes contributions of flow through degraded cement, disturbed soil/rock matrix, the micro annulus between cement and matrix, local fractures, and sometimes corroded steel. US studies of effective well permeability are fairly limited and highly dependent on well construction and local hydrogeological conditions (Duguid et al. 2013; Hawkes and Gardner 2013; Gasda et al. 2011; Crow et al. 2010; Carey et al. 2010; Rocha-Valadez et al. 2014). Many are limited to wells in the production phase, the exception being Hawkes and Gardner (2013). More studies of effective well permeability in Australian conditions are required for wells in all stages of development – exploration, production, decommissioning (i.e. where work has been undertaken to maintain bore integrity and remediate the site) and abandoned (walk away approach, i.e. where a bore is simply no longer in use). In dual-phase systems, determination of effective permeability needs to consider relative permeability. This will also require determination of capillary pressure relationships for the cemented bore/well annulus.

6 Key findings

This study reviewed well failure mechanisms and failure rates associated with conventional and unconventional oil and gas extraction, and identified knowledge gaps in the context of understanding the potential impacts of coal seam gas well failure on aquifer connectivity. Well failure or loss of well integrity may result from a well breach (or number of well breaches), and can take the form of a hydrological or environmental breach. Three types of breaches are discussed, i.e. well breach, hydrological breach, and environmental breach. Well failure mechanisms are addressed for each phase of an entire CSG well life cycle, i.e., well design and/or construction, production and abandonment phase.

Well failure rates were reviewed based on three large datasets for onshore oil and gas wells, as well as coal seam gas wells, in the US and Canada. Two further studies considered offshore oil and gas wells, one in the Gulf of Mexico (US) and one offshore Norway.

The onshore conventional oil and gas studies identified that:

- well barrier failure rates (likely not resulting in leaks to groundwater) ranged from 0.035 to 0.1% for a well population over 250,000, with well failure rates estimated to be one order of magnitude lower (Ohio and Texas, US)
- the ratio of the number of wells with surface casing vent flow and gas migration outside the surface casing to the entire well population over 350,000 was 4.5%. The well failure rate was much higher (15%) in the specifically designated test area with a well population over 20,000 (Alberta, Canada).

Analysis of coal seam gas well failure rates in San Juan Basin, US, revealed that:

- the well failure rate in La Plata County was estimated to be approximately 3.4% for more than 1000 coal seam gas wells during the period between 1991 and 2000
- the well failure rates in Ignacio-Blanco field ranged from 1.3% to 8.6% during the period between 1992 and 2010 with an average of 3.6%. The total number of coal seam gas wells with casing head pressure measurement averaged approximately 400 per year.

As far as the integrity of offshore oil and gas wells is concerned, the review highlighted the following findings:

- in the Gulf of Mexico, US, approximately 10 per cent of wells reached sustained casing pressure (SCP – indicating well barrier failure but not necessarily well integrity failure) within one year of being completed, and this figure rose to 50 per cent after 15 years of production
- in offshore Norway 18% of the wells surveyed in a pilot study (75 out of 406 wells surveyed) had integrity failure, issues or uncertainties.

A previous review indicated that coal exploration bores are the most significant legacy type in Queensland, mainly due to their abundance (30,000 in the Surat Basin with another 100,000 in the Bowen Basin) and possible lack of appropriate decommissioning (Commonwealth of Australia 2014a). The current review included one study that evaluated the potential integrity of water bores in the Surat Basin, Australia. One of the main findings is that a large number of bores (about 3500) were constructed prior to 1968, and are assumed to have poor integrity. This assumption is based on the fact that these bores were cased with steel, which would have corroded significantly over time.

A study on well integrity of CSG wells in Queensland covering the period 2010-2015 concluded that the risk of a subsurface breach of well integrity was assessed to be very low to near zero. The same study concludes that all reported surface well head leaks were subsequently fixed.

A second part of the study involved the conceptualisation of preferential flow pathways for use in local-scale and regional-scale groundwater modelling. Building on the literature review on well failure mechanisms and rates relevant to CSG environments, major pathways for movement of groundwater between strata have been identified. Pathways have been linked to failure of: i) uncased exploration bores backfilled with rock material upon decommissioning, ii) cemented production wells plugged with cement cores upon decommissioning, iii) wellbores during hydraulic fracturing, and iv) oil and gas wells repurposed for water extraction and water bores in which casing has corroded and/or there is no cementing of the annulus.

Pathways involving flow through leaky wells may be represented in groundwater models through a Darcy-type flow conceptualisation, using the effective hydraulic conductivity of the well. In US studies of abandoned production bores, cement porosity was observed to have a log-linear relationship with cement hydraulic conductivity, while effective well conductivity (from 10^{-11} to 10^{-6} m/s) was found to be considerably greater than cement core conductivity (from 10^{-12} to 10^{-8} m/s).

Flow through leaky wells and abandoned exploratory bores may also be calculated from equations developed for flow through conduits. Both laminar and turbulent flow conditions may exist: the former is more likely in flow through the bore annulus or degraded concrete while the latter may occur in flow through fully open wells.

Selection of appropriate modelling codes depends on the nature of the questions being asked. The Connected Linear Network (CLN) module package in MODFLOW-USG was identified to have the required capability to model passive water flow through leaky wells for a fully saturated medium (single-phase water flow). For cases where dual-phase flow occurs, especially within the CSG well fields, a dual-phase flow simulator may be more appropriate although its regional-scale implementation across potentially hundreds or thousands of wells is computationally very demanding.

The review on well failure mechanisms and well failure rates identified a number of knowledge gaps, in particular:

- Well failure rate. There are currently few data/information publically available to establish well failure rates for CSG wells across all gas production fields in Australia
- Impacts of well-life stress and pressure on the integrity of cement sheath and cement bonds are not well understood
- Impacts of reservoir compaction induced by depressurisation/dewatering in coal seams on the integrity of cement sheath and cement bonds are not well understood
- There is a lack of data on long-term (100-1000 years) cement durability and degradation rate under typical CSG well downhole conditions in Australia
- Well failure criteria. There is a need to establish an acceptable minimum rate of fluid released from a well that has a negligible impact on the environment.
- Better information is required on effective well permeability, especially for exploration bores or decommissioned wells and in Australian conditions.

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Appendix 1 Equations for flow in porous media and conduits

The Darcy equation for flow in porous media is:

$$Q = KA\frac{dh}{dL} \tag{4}$$

where K is the effective hydraulic conductivity of the well, the cement annulus or the microannulus between the cement and rock matrix or steel conduit, A is the cross sectional area of the well, the cement annulus or the microannulus between the cement and rock matrix or steel conduit, dh is the head difference between the water entry and exit points from the well or annulus, *and* dL is the length of the flow path between the points at which dh is measured.

Laminar flow in conduits may be computed using the Hagen- Poiseuille equation:

$$Q = \frac{\Delta p \pi d^4}{128 \mu L} \tag{5}$$

where Δp is the change in pressure ($ML^{-1}T^{-2}$), μ is the dynamic viscosity ($ML^{-1}T^{-2}$), L is the length of the conduit (L), Q is the volumetric flow rate (L^3T^{-1}), d is the diameter of the conduit (L).

The Darcy-Weisbach equation for friction losses in conduits is:

$$h_f = f_D \frac{L}{D}\frac{u^2}{2g} \tag{6}$$

where h_f is the head loss due to friction (L), L is the length of the pipe (L), D is the hydraulic diameter of the pipe (L), u is the average flow velocity for the cross sectional area (LT^{-1}), g is the local gravitational acceleration (LT^{-1}),f_D is the Darcy friction factor (-).

The Hazen-Williams empirical equation for losses turbulent flow is:

$$V = kCR^{0.63}S^{0.54} \tag{7}$$

where V is the fluid velocity (LT^{-1}), k is a units conversion factor (0.849 for SI units), C is a roughness factor ($L^{0.37}T^{-1}$), R is the hydraulic radius (L) and S is the head loss per length of conduit (-).

The Manning equation for flow through an open channel is:

$$Q = \frac{1}{n}AR^{\frac{2}{3}}S^{\frac{1}{2}} \tag{8}$$

where Q is the discharge (L^3/T), n is the Manning roughness factor ($TL^{-1/3}$), A is the cross sectional area of the conduit (L^2), R is the hydraulic radius (area divided by wetted perimeter) of the conduit (L) and S is the head loss per length of conduit (-).

The hydraulic diameter (D) and area (A) of an annulus are calculated as follows:

$$D = 2(r_o - r_i) \tag{9}$$

where r_o is the radius of the outer part of the annulus, r_i is the radius of the inner part of the annulus. The area of an annulus A is given by:

$$A = \pi\left(r_o^2 - r_i^2\right) \tag{10}$$

The wetted perimeter *P* (assuming a full, vertical conduit) is:

$$P = 2\pi\left(r_o + r_i\right) \tag{11}$$

And hydraulic diameter *D* is:

$$D = \frac{4A}{P} \tag{12}$$

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