Assessment of scientific knowledge of shale gas and shale oil potential impacts

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Foreword

The aim of this assessment is to identify the potential environmental impacts of shale gas and shale oil (shale gas and oil) extraction in Queensland; impacts on other industries, including agriculture and tourism; and how these impacts are managed under the current Queensland regulatory framework.

The report provides an assessment of the current scientific knowledge of the potential impacts of shale gas and oil activities for regulators, governments and the community to consider as they seek to manage, respond to and understand this emerging industry.

Context

Shale gas and oil deposits are found in very fine-grained rocks formed from the compaction and burial of organic matter, silt and clay. Typically, shale gas and oil deposits require specialised extraction techniques such as hydraulic fracture stimulation and horizontal drilling to allow the trapped natural gas or oil to flow up the well to the surface.

Shale gas and oil exploration is at a very early stage in Queensland. Although more exploration and appraisal are required over the next few years, early indications suggest that Queensland has significant shale gas and oil resource potential. As this is an emerging industry, it is timely to take stock and identify any potential environmental impacts associated with significant activity in this industry, and potential impacts on other industries, including agriculture and tourism. There are opportunities to learn from international experience in shale gas and oil, and from similar industries in Queensland, such as coal seam gas development.

Scope

It is not the intention of this assessment to assess local impacts from a specific project – any future development proposal would need to be assessed on its own merits in the local geographical context. This assessment provides an overview of the industry, and the development and extraction of shale gas and oil resources, with a comparison with other forms of petroleum and natural gas extraction. Queensland's known shale gas and oil resources, and the progress of the industry to date are summarised.

Potential environmental impacts of upstream components of shale gas or oil projects across their life cycle have been qualitatively assessed. Upstream activities include the exploration, appraisal, development and production stages to the point where gas or oil is delivered to pipelines for transport to processing facilities. Downstream processing activities were not considered. Consideration has been given to impacts on:

- human health
- land erosion and contamination
- surface and groundwater resources, including water use, and potential impacts on water quality, riverine ecosystems and aquifers
- native vegetation and fauna
- air quality, including greenhouse gas emissions (fugitive emissions)
- waste management
- noise impact and amenity (e.g. impacts of workers' camps and construction)
- potential seismic activity (associated with hydraulic fracturing or wastewater reinjection).

The assessment provides a summary of how Queensland's regulatory framework for shale gas and oil applies to these impacts. A normative assessment (i.e. a critique) of the regulations is beyond the scope of this assessment. Impact mitigation measures used by industry have not been considered in detail.

The impacts have been compared with those of other forms of petroleum and natural gas extraction. The assessment also considers potential for impacts on other industries, including agriculture and tourism.

Approach

CSIRO conducted a critical analysis of a selection of significant recent literature on the impacts of shale gas and oil. These studies are predominantly based on the North American industry, and have leveraged more recent and comprehensive assessments conducted by government organisations such as the United States Environmental Protection Agency and the Northern Territory Independent Commission on Hydraulic Fracturing.

Impacts have been discussed in terms of their materiality, which considers the scale or magnitude of the impacts, and whether they are an integral part of the shale gas and oil extraction process or infrequent or inadvertent events. The study focuses on direct impacts. Indirect impacts and cumulative impacts have not been considered in detail.

Assessing impacts into the future is challenging for a new industry that may have a substantial geographic footprint, has the potential for cumulative effects, has evolving technologies and methods, and has limited history in Australia. Areas of uncertainty around the impacts are also discussed.

The requirement for regulatory focus of the potential impacts of shale gas and oil development that have been identified have also been evaluated. This is based on whether the activities that cause the impacts are already conducted and regulated in Queensland, or whether they will be new or conducted at a significantly greater scale. This indicates potential areas for additional focus during the assessment and approval of any future projects.

The assessment has focussed on negative impacts. Positive impacts were not in scope.

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Executive summary

Shale gas and oil resources are attracting increased attention globally, given their potential as an energy resource. Queensland holds significant shale gas and oil resource potential, and to date these resources have seen only limited exploration. These potential resources have been identified in nine basins across Queensland that are located within a range of ecosystems, from deserts to rainforests, and that have land uses ranging from farms to national parks.

This review identifies the potential environmental impacts of shale gas and oil extraction, as well as potential impacts on other industries, including agriculture and tourism. The review is not intended to provide a risk assessment of the development of shale gas and oil resources in Queensland; rather, it provides an overview of potential impacts to inform stakeholders. It is important to emphasise that the focus is on the identification of potential impacts and high-level analysis of their materiality, not absolute risk estimation. Potential impacts are impacts that *may* occur in certain circumstances. Controls can be used to reduce the chance of impacts happening or to reduce their severity. The Queensland regulatory framework that currently applies to these potential impacts is also summarised.

Potential impacts were identified through a critical analysis of selected published research on shale gas and oil developments. There is a growing body of literature on potential shale gas and oil impacts, with national-scale reviews from Australia, the United States, Canada, Europe and the United Kingdom. There are few examples of large-scale development of shale gas and oil industries outside the United States; therefore, the United States experience over the past few decades provided an important evidence base for impacts.

There has been a lot of research and reports on shale gas and oil impacts, particularly from countries where either shale gas and oil or more generally unconventional gas industries are further developed than in Australia. In particular, shale gas and oil development is a well-established industry in North America. The learnings, risks and impacts coming from North American shale gas and oil activities are well documented in the literature and provide valuable insights into how these resources may be developed in Queensland.

Also, many shale gas and oil activities are already conducted in Queensland in the development of other gas and oil resources, including coal seam gas (CSG). The knowledge about these activities and the associated risks can help to assess the risks that are likely to be present in Queensland shale gas and oil development.

The technologies that will be used to develop shale gas and oil resources are well established in the United States. Many of these technologies have already been used in Australia and in Queensland. Drilling, including horizontal ‘sections’, and hydraulic fracturing are processes that have been used for tight gas and CSG resources. Similarities in these technologies used for CSG and shale gas and oil resources mean that there may be similarities in potential impacts for these resources.

Queensland has a well-established CSG industry. A key point of similarity between shale gas and oil and CSG developments is the scale of development: both target reservoirs that are laterally extensive and require a large number of wells. This contrasts with conventional gas and oil resources, which typically have a restricted geographic extent and higher productivity per well. Although many similarities exist between shale gas and oil extraction and the more well-known CSG extraction, there are also key differences. Shale gas extraction requires less well pads per area and therefore leads to significantly less surface disturbance because of the drilling of multiple wells with long horizontal sections from a single well pad. Shale gas and oil resources lie significantly deeper underground, some 1–4 km deeper than CSG resources, which usually occur within 200–800 m of the land surface. Shale gas and oil extraction will use more water than CSG, because shales always require hydraulic fracturing to extract the gas and oil, whereas CSG requires hydraulic fracturing on only a limited number of wells. In contrast, CSG operations produce more water than shale gas and oil because the coal seam must be dewatered to allow gas to flow.

This review has identified few potential impacts unique to shale gas and oil developments. The key impacts specific to shale gas and oil that were consistently identified in the literature relate to water. These water impacts provide the conduit to potential impacts on other environmental values, such as biodiversity, land contamination and human health. Four main water impacts and issues were identified:

- **water use** – where the water required for drilling and hydraulic fracturing will be drawn from, and what impacts will accrue, particularly for competing users
- **water reuse and wastewater treatment** – management of wastewater from shale gas and oil projects, its reuse and potential treatment options
- **water contamination** – the potential for inadvertent surface spills and leaks, leading to impacts on surface water and groundwater, and appropriate management and monitoring
- **long-term well integrity** – the potential for old wells to become conduits for contamination, and how legacy issues will be managed for both point-source and cumulative impacts.

Other moderately significant potential impacts identified for shale gas and oil are:

- disturbance and erosion of soil from the development of surface infrastructure (well pads, access tracks, pipelines)
- contamination of land or water through spills of waste materials (drilling fluids, hydraulic fracturing fluids, flowback water)
- human health impacts for those living close to shale gas and oil operations due to changes in air quality, though this impact may not be an issue in the remote areas of Queensland that are most prospective for shale gas and oil resources
- human health impacts for those living in shale gas and oil development regions due to stress resulting from rapid industrial development and its effects
- loss, decrease in quality, or fragmentation of habitat for native vegetation and fauna due to vegetation clearing for infrastructure development; these impacts will be very location specific
- introduction of invasive species (particularly weeds), affecting agriculture and native vegetation and fauna
- decreased access to traditional lands for Aboriginal and Torres Strait Islander communities.

As part of the evaluation of the potential impacts of shale gas and oil development, CSIRO evaluated the requirement for regulatory focus of potential impacts.

Because most technologies and activities are already conducted for other petroleum resources in Queensland, most impacts should be covered under the current regulatory framework. The two most relevant pieces of legislation are the *Petroleum and Gas (Production and Safety) Act 2004*, under which developers are granted rights to explore for and develop petroleum resources, and the *Environmental Protection Act 1994*, which requires developers to apply for an environmental authority (EA) for their operations. The EA sets out the environmental conditions and risk management requirements for the development and is usually based on an environmental impact assessment.

CSIRO identified those impacts that may require additional attention during the assessment and approval process because they are new, or occur at an increased scale. These have been categorised as a high or moderate requirement, based on the potential level of impact:

- High requirement
  - potential impacts related to the taking of surface water or groundwater
- Moderate requirement
  - potential impacts related to the disposal of waste water (mainly treated flowback water)
  - potential impacts related to surface spills or leaks of chemicals, drilling fluids, hydraulic fracturing fluid, flowback water and produced water
  - potential impacts related to hydraulic fracturing activities
  - potential impacts related to greenhouse gas emissions
  - potential impacts related to access to land and other surface activities
  - potential social and economic impacts, including demand for local labour and impacts on traditional land users.

The literature identifies the problems that arise when there are significant data gaps in the area of baseline studies (before development) for monitoring, ongoing assessment and adaptive management for risk mitigation. The development of baseline studies will be a necessary part of the responsible development of a potential future shale gas and oil industry in Queensland.

1 Introduction

Queensland has significant potential for both shale gas and shale oil (shale gas and oil[1]) resources. Exploration for these resources is at a very early stage, and there is some uncertainty about the resource characteristics, the technologies that will be required and the economics for their development. As with any industry, development of these resources will come with potential impacts, both positive and negative, on the environment, society and the state's economy, as well as on current industries. It is important to assess these positive and negative impacts of this potential future resource industry so that proper consideration can be given as to its development how they will be and management.

Potential impacts and overall aim of this report

The overall aim of the report is to provide an assessment of the current scientific knowledge of the potential impacts of shale gas and oil activities for regulators, governments and the community to consider as they seek to manage, respond to and understand this emerging industry.

Potential impacts are impacts that ***may*** occur in certain circumstances.

Activities can be managed to reduce the chance of impacts happening or to reduce their severity.

This management can be provided through regulatory controls and appropriate industry practices.

Shale gas and oil developments are well-established industries in North America; their development has been instrumental in transforming the energy economy in the United States and Canada. Queensland has had oil and gas development since the 1960's, and has seen the rapid development of unconventional gas resources in the form of coal seam gas (CSG) over the last 15 years. The state's CSG resources now supply the majority of gas used in the eastern Australian gas market. Most of this gas goes to the liquefied natural gas (LNG) export industry via 3 LNG plants near Gladstone, with a combined capacity to deliver more than 25 million tonnes per year to international markets. In 2012, Santos developed Australia's first commercially producing shale gas well in the Cooper Basin in South Australia. As yet, no other Australian state has producing shale gas wells, but many are at various stages of resource investigation.

The experience gained in North America in developing shale gas and oil resources, and the technologies used to develop them, provide valuable insights into how these resources may be developed in Queensland. The documented impacts of the development of these resources in North America help to identify potential impacts of these industries in Queensland. Equally, some aspects of shale gas and oil development will be similar to CSG and conventional petroleum resource development in Queensland.

[1] In this review, shale gas and shale oil resources are referred to collectively as shale gas and oil resources. In reality, these resources form a continuum from shale gas resources that contain only gas to shale oil resources that contain only oil, with shale gas and oil resources in between that contain both oil and gas. At the level of detail of this report, the technologies for the extraction of these resources and the potential impacts are likely to be very similar. The characteristics of shale gas and oil resources, and their development, in comparison with other gas and oil resources, are described in Section 2.

Australian inquiries and studies relevant to shale gas and oil activities

There have been a number of inquiries and studies conducted in Australia's states and territories relevant to shale gas and oil activities. These include independent inquiries, parliamentary inquiries and studies commissioned by government. The terms of reference also vary, with differing emphasis on the scientific understanding of the risks of shale gas and oil development, the social and economic impacts, concerns of the community, the effectiveness of current regulatory frameworks for managing risks and impacts, and the role of unconventional gas as an energy source now and into the future.

The following recent inquiries and studies have focussed on shale gas and oil or hydraulic fracturing as applied to shale gas and oil resources:

- The independent scientific Inquiry into hydraulic fracturing in the Northern Territory, 2018, led by Justice Pepper (Pepper *et al*, 2018).
- The South Australian Parliament Natural Resources Committee inquiry into unconventional gas (fracking) in the south east of South Australia, 2016 (South Australian Parliament Natural Resources Committee, 2016).
- Western Australia Standing Committee on Environment and Public Affairs inquiry into the Implications for Western Australia of Hydraulic Fracturing for Unconventional Gas, 2015 (Western Australia Standing Committee on Environment and Public Affairs, 2015).
- Victoria Environment and Planning Committee inquiry into onshore unconventional gas in Victoria, 2015 (Victorian Environment and Planning Committee, 2015).
- Independent Inquiry into Hydraulic Fracturing in the Northern Territory, 2014, led by Justice Hawke (Hawke, 2014).
- Engineering Energy: Unconventional Gas Production – A study of shale gas in Australia. Report for the Australian Council of Learned Academics, 2013 (Cook *et al.*, 2013).

When assessing the scientific understanding of the risks of shale gas and oil development, these inquiries and studies have all found that the risks are low, although they do acknowledge there is some uncertainty. They all make recommendations or note the need for changes to the regulatory frameworks in the relevant jurisdictions to reduce the likelihood of adverse impacts. The Northern Territory and Western Australian inquiries found that shale gas and oil development / hydraulic fracturing could proceed with minimal risk if the appropriate regulations and industry practices were in place.

All of the inquiries note community concerns about the risks of hydraulic fracturing or shale gas and oil activities. Although the South Australian Fracking Inquiry found that the risks of hydraulic fracturing are low, they recommended a moratorium on hydraulic fracturing in south east South Australia until the industry could gain a social licence to operate. The parliamentary committee conducting the Victorian inquiry could not reach a majority view on the future of unconventional gas development.

The Australian Senate's Select Committee on Unconventional Gas Mining, 2016, which was chaired by Senator Glenn Lazarus, lapsed with the calling of the general election in 2016. It did not produce a final report and has not been used in this review. There have also been several inquiries with a focus on CSG activities. These include a NSW parliamentary inquiry (New South Wales General Purpose Standing Committee No. 5, 2012) and an independent review by the NSW Chief Scientist (O'Kane, 2014). There have also been several inquiries held by the Australian Senate looking at aspects of the CSG industry, however these did not have a science focus.

1.1 Navigating this report

This report first provides information on the Queensland context and environment, canvassing bioregions, water resources, dominant land uses and locations of the population. This introductory section includes:

- a summary of the Queensland context, in terms of ecosystems, water resources and land use
- an overview of the locations of known and prospective shale gas and oil resources in Queensland
- an outline of the existing regulatory framework for managing the impacts of petroleum resource development in Queensland.

One of the aims of regulation is to minimise and manage potential negative impacts of industries by requiring operators to conduct their operations in certain ways. A critique of the effectiveness of the current regulatory framework in managing the impacts of existing petroleum operations or the potential impacts of future operations was outside the scope of this review.

The report then presents further information in two parts.

Part I provides an overview of shale gas and oil resources, their characteristics and the technologies used in their development. The following topics are covered:

- the geology of shale gas and oil resources
- a description of the development life cycle for these resources, including typical operational aspects, and the technologies used in their development
- a comparison with CSG development
- a description of key technologies used in shale gas and oil production, including drilling, hydraulic fracturing and gas processing.

Part II provides a review and a summary of key literature on the environmental impacts of shale gas and oil developments from around the world, including a number of inquiries conducted in Australia. The impacts have been compared mostly with those of CSG and, where relevant, the conventional petroleum sectors in Queensland. The environmental impacts have been divided into the following areas:

- surface water and groundwater resources, including water use and potential impacts on water quality, riverine ecosystems and aquifers
- land erosion and contamination
- waste management
- human health, including noise and amenity
- native vegetation and fauna
- air quality, including greenhouse gas emissions (including fugitive emissions)
- induced seismicity
- other industries, including impacts on agriculture and tourism.

Each chapter has the following structure:

1. Chapter summary of the key impacts identified, including an overview table of the nature and scale of impacts.
2. Relevant context for the impact area.
3. Discussion of potential impacts.

4. Comparison with CSG development.
5. Summary of relevant regulations that apply in Queensland.

It is important to note that assessing future potential impacts is challenging for a new industry that may have a substantial geographic footprint, has the potential for cumulative effects, is influenced by changing policy, has evolving technologies and methods, and has a limited history in Australia. Areas of uncertainty around the impacts in each chapter are identified and outlined.

It is also important to note that this review is not intended to provide a risk assessment of the development of shale gas and oil resources in Queensland. Such an assessment would be inappropriate at the state-wide scale of this review. Environmental risk assessments require a detailed understanding of the specific activities that will be conducted and the specific environment in which they will be conducted, as well as an assessment of the controls that would be put in place by the development proponent to manage the identified risks. These assessments are more appropriately conducted on a project-by-project basis when that level of detail is known.

1.2 The Queensland environment

The impacts of any industry depend on the nature of the environmental values, communities and industries with which they coexist. An environmental value can broadly be defined as a quality or physical aspect of the environment that is important for the health of the ecosystem and public use, including amenity and health. The environmental values of a particular area depend on the ecosystems present in the area, as well as the way people use or value the area.

The state of Queensland covers a large geographic area (1,852,642 km^2), with a diversity of ecosystems and land uses. This diversity reflects the spatial variability in climate (rainfall, temperature), water resources, vegetation, soil types and underlying geology. In this section, this variability is discussed to provide context for the review of impacts throughout the rest of the report.

Most of the literature on the impacts of shale gas and oil developments pertains to the North American context. The ecosystems and land uses in those regions are different from those in Queensland (although similarities may be present), and this must be considered in understanding the relevance to Queensland of the impacts described in literature. Three main areas are considered: bioregions, water resources and land use. These areas are all closely related to each other.

A useful source of information on Queensland's environmental assets and their current condition is available in *Queensland state of the environment* (Queensland Department of Environment and Heritage Protection, 2017a).

1.2.1 Bioregions

The commonly accepted approach to describing bioregions in Queensland is Queensland's Regional Ecosystem Framework (Queensland Herbarium, 2014, 2016). The highest-level components of this framework are the bioregions, which are based on the Interim Biogeographic Regionalisation for Australia (IBRA; see Environment Australia, 2000). IBRA was developed in the early 1990s and has been adopted by all levels of government in Australia as a way of describing biogeographic regions. Bioregions are large, geographically distinct areas that have similar geology, landform patterns, climate, ecological features, and flora and fauna.

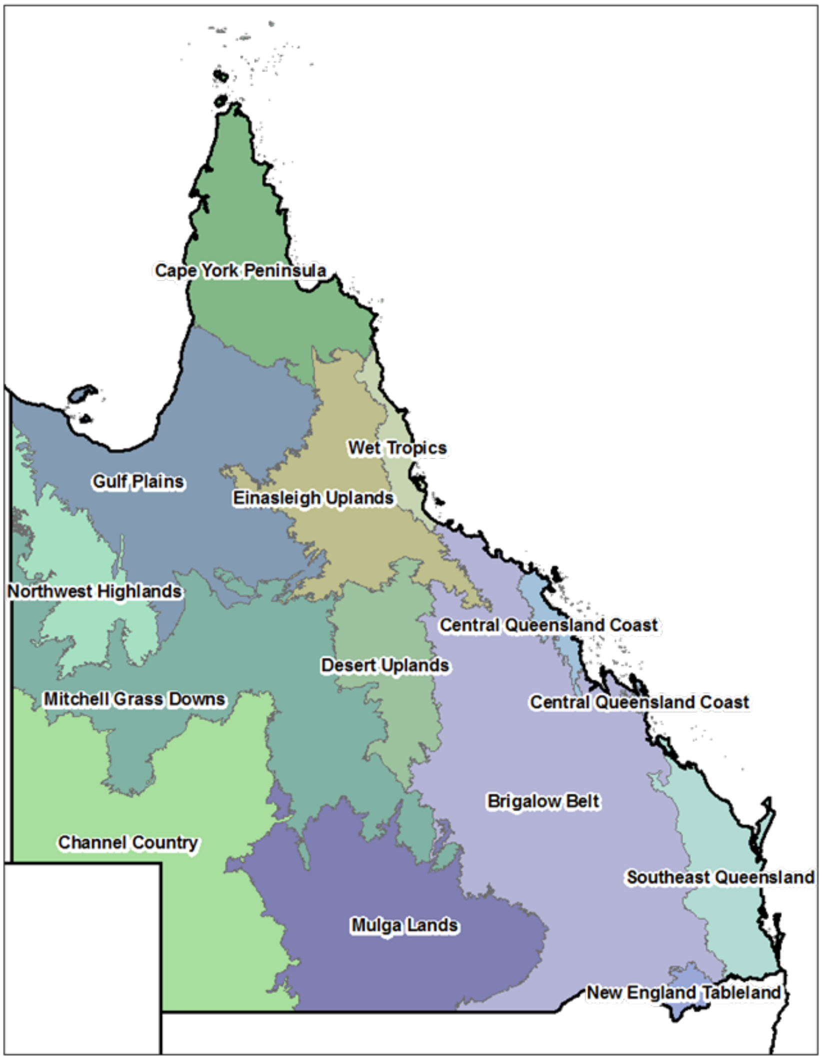
Queensland's Regional Ecosystem Framework has 13 bioregions. Queensland contains all or part of 16 IBRA bioregions; however, some of these have been merged for the Regional Ecosystem Framework. The Queensland bioregions are summarised in Table 1 and displayed in Figure 1, with full descriptions in

Appendix B. The bioregions provide a high-level description suitable for this study. Both IBRA and the Regional Ecosystem Framework contain subdivisions of these bioregions.

Table 1 Summary descriptions of Queensland bioregions

Bioregion	Description
Brigalow Belt	Volcanics and sedimentary rocks, uplands and ranges. Subhumid to semi-arid. Woodlands and open forests of *Eucalyptus*, *Acacia* (including brigalow) and *Casuarina*; semi-evergreen vine thicket in the south. Region reaches the coast in the dry coastal corridor of Proserpine–Townsville
Cape York Peninsula	Complex geology. Includes ranges with high-altitude/high-rainfall areas, deeply dissected sandstone plateaus and lowlands, extensive sand sheets dissected by intricate drainage systems, laterite, extensive coastal plains and aeolian dunefields. Several large river systems. The vegetation is predominantly woodlands, heathlands and sedgelands, and vine forests. Mangrove forests on both the west and east coasts. Tropical humid/maritime climate
Central Queensland Coast	Humid, tropical coastal ranges and plains. Rainforests (complex evergreen and semi-deciduous notophyll vine forest), *Eucalyptus* open forests and woodlands, *Melaleuca* wetlands
Channel Country	Low hills on Cretaceous sediments. Semi-arid. Grasslands and intervening braided river systems of coolibah woodlands and lignum/saltbush shrublands. Arid dunefields and sandplains with sparse shrubland, spinifex hummock grassland, and cane grass on deep sands along dune crests. Salt lakes and many clay pans are dispersed among the dunes
Desert Uplands	Ranges and plains on dissected Tertiary surface and Triassic sandstones. Predominantly *Eucalyptus* woodlands
Einasleigh Uplands	High plateau of Palaeozoic sediments, granites and basalts. Dominated by ironbark woodlands
Gulf Plains	Marine and terrestrial sedimentary deposits; plains, plateaus and outwash plains. Woodlands and grasslands
Mitchell Grass Downs	Undulating downs on shales and limestones. Grasslands and *Acacia* low woodlands. Grey and brown cracking clays
Mulga Lands	Undulating plains and low hills on sediments; red earths and lithosols. *Acacia* shrublands and low woodlands
New England Tablelands	Elevated plateau of hills and plains on sediments, granites and basalts. Dominated by stringy bark/peppermint/box species woodlands
Northwest Highlands	Rugged hills and outwash, primarily associated with Proterozoic rocks. Undulating terrain with scattered low, steep hills on Proterozoic and Palaeozoic sedimentary rocks; skeletal soils and shallow sands. Low open *Eucalyptus* woodlands with spinifex understorey. Semi-arid
Southeast Queensland	Metamorphic and acid to basic volcanic hills and ranges; sediments; extensive alluvial valleys and coastal deposits, including high dunes on the sand islands. Humid. *Eucalyptus* tall open forests; *Eucalyptus* open forests and woodlands; subtropical rainforests; and small areas of cool temperate rainforest, semi-evergreen vine thickets, *Melaleuca* wetlands, *Banksia* low woodlands, heaths and mangrove/saltmarsh communities
Wet Tropics	Rugged rainforested mountains. Extensive plateau areas along its western margin, as well as low-lying coastal plains. Extensive areas of tropical rainforest, plus beach scrub, tall open forest, open forest, mangrove and *Melaleuca* woodland communities

See Appendix B for more detailed descriptions.
Source: Environment Australia, 2000



Source: Queensland Department of Science, Information Technology and Innovation, 2010

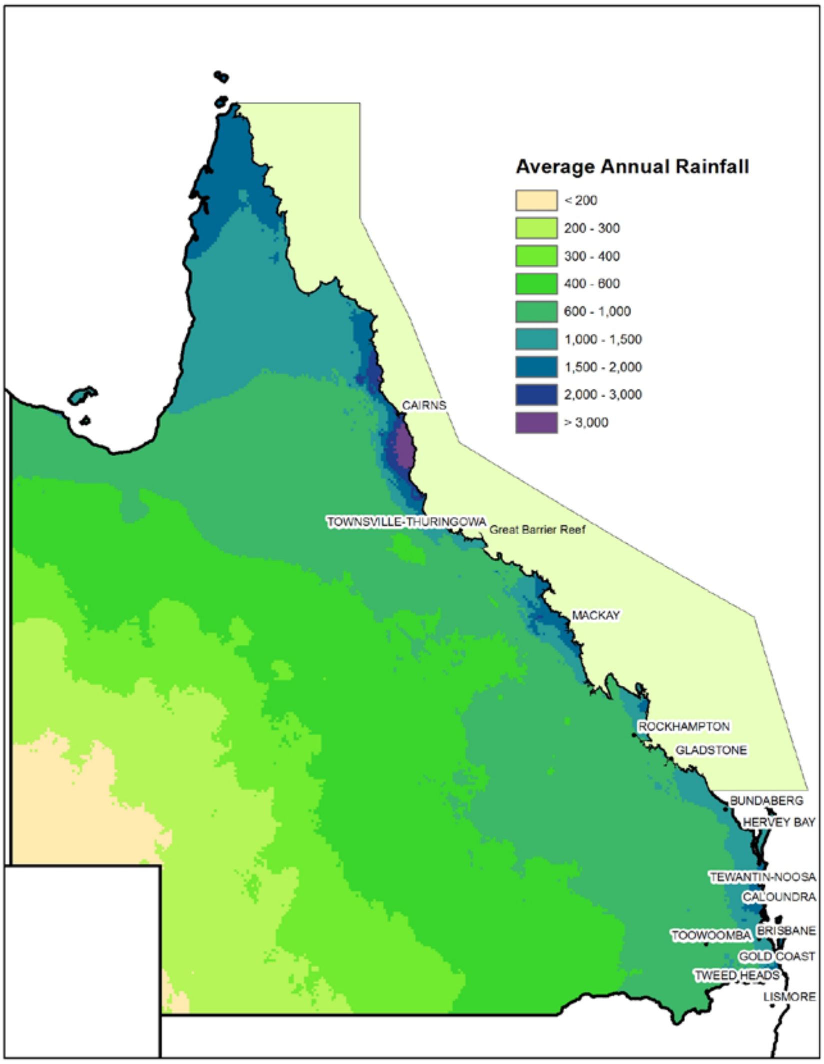
Figure 1 Queensland's bioregions

1.2.2 Water resources

Queensland's water resources are dominated by surface water in the coastal areas and groundwater in the inland areas. This distribution reflects rainfall and surface drainage patterns. Generally, rainfall is highest near the coast and towards the north, and decreases further inland and to the south-west of the state. The annual rainfall in Queensland is generally within the range of 1,000 to 1,600 mm, with extremes of 200 mm in the south-west and 3,200 mm in the Wet Tropics region (see Figure 2). Rainfall across Queensland is highly seasonal, with most rain falling in summer and least during winter. There is also a high degree of variability from year to year, particularly in inland regions. Total annual surface runoff is around 160,000,000 megalitres (ML), with 53% in the East Coast drainage division, 41% in the Gulf of Carpentaria drainage division, and 6% in the inland drainage divisions (Queensland Environmental Protection Agency 1999). The drainage divisions are shown in Figure 3.

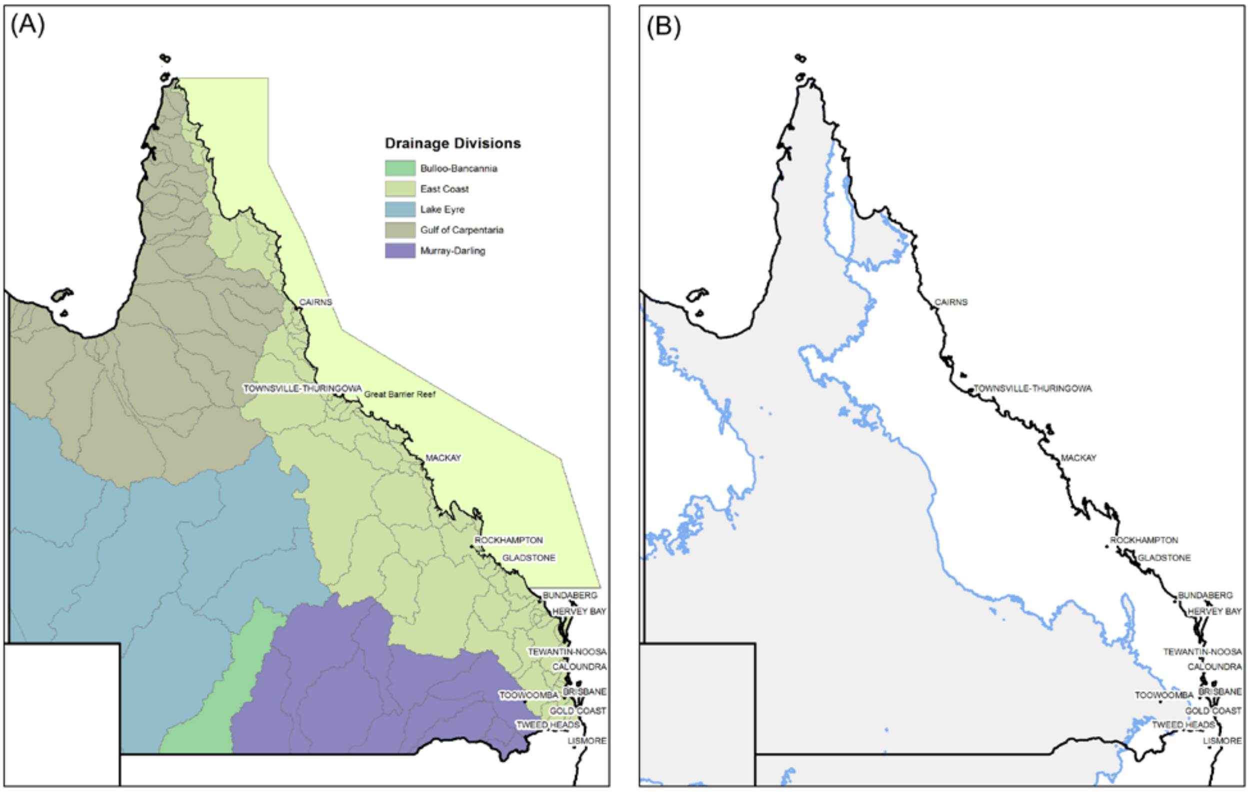
Groundwater is a significant resource in Queensland, particularly in inland regions. The Great Artesian Basin (GAB; Figure 3) underlies much of the inland regions of Queensland and contains more than 65,000,000,000 ML (65 billion ML) of water, enough to fill 26 billion Olympic-sized swimming pools (Queensland Department of Natural Resources and Mines, 2017b). The GAB includes the Eromanga, Surat and Carpentaria sedimentary basins. There are around 6,500 licences and 21 permits to take water in the Queensland portion of the GAB, and annual use from the GAB in Queensland is approximately 315,000 ML (Queensland Department of Natural Resources and Mines, 2017b). Most of this water (196,400 ML) is either used for livestock or domestic purposes, with more than half of that estimated to be lost in the process of watering stock. Approximately 20% is accounted for by the petroleum sector. The use of GAB water for irrigation is limited due to water quality issues.

Total water consumption in Queensland is around 3,958,000 ML per year (around 1.6 million Olympic swimming pools). Agriculture is the dominant user (Figure 4), consuming approximately two-thirds of the total. Most of this water is sourced from surface runoff (Australian Bureau of Statistics, 2017).



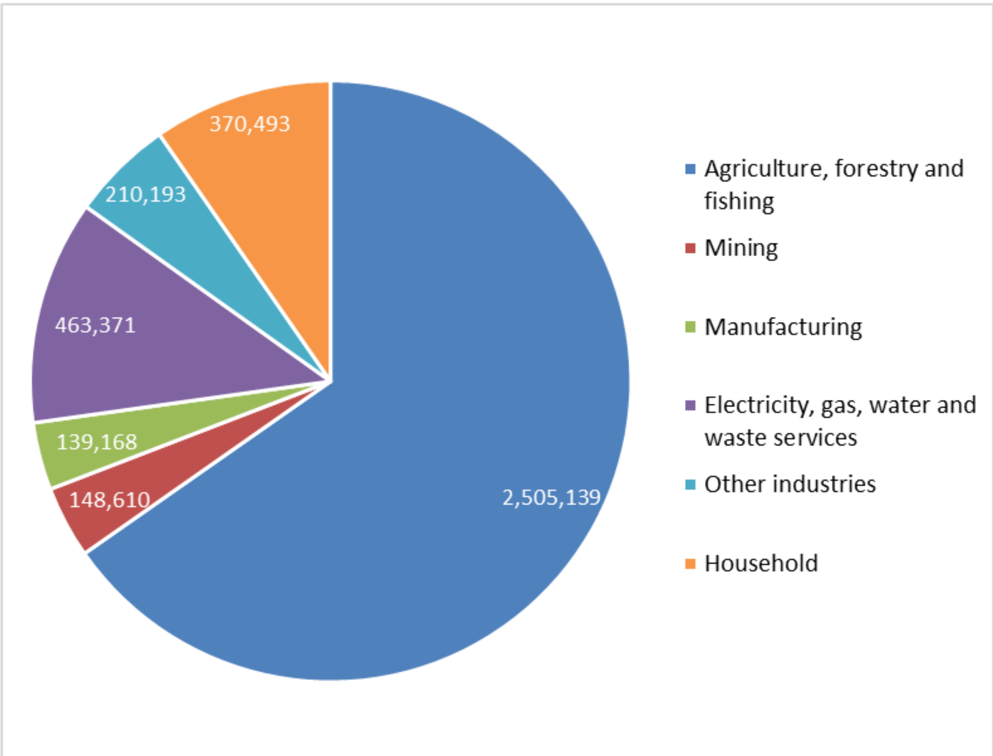
Source: Bureau of Meteorology, 2016

Figure 2 Average annual rainfall for Queensland, 1961–90



Note: Runoff water flows into the Coral Sea and Pacific Ocean from the East Coast drainage division, into the Gulf of Carpentaria from the Gulf of Carpentaria drainage division, and into inland river systems from the Lake Eyre, Bulloo–Bancannia and Murray–Darling drainage divisions.
Sources: (A) Queensland Department of Natural Resources and Mines, no date a; (B) Geoscience Australia, 2012

Figure 3 (A) Queensland's major drainage divisions and (B) outline of the Great Artesian Basin



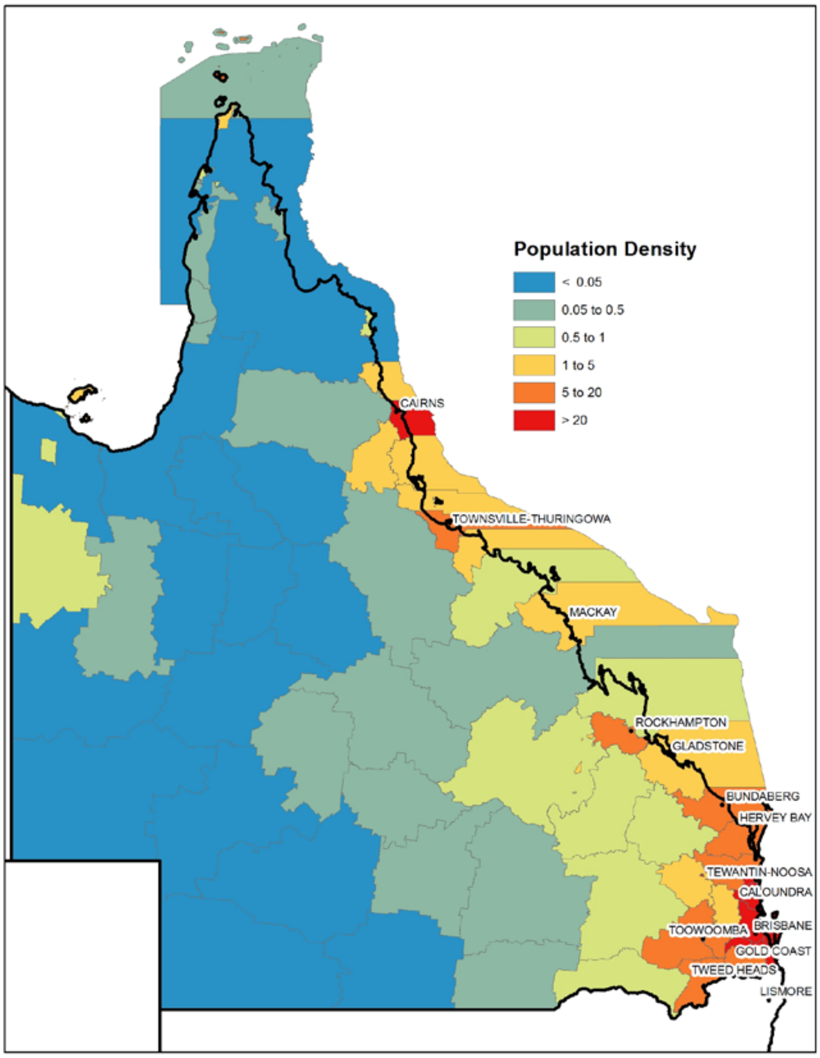
Source: Australian Bureau of Statistics, 2017

Figure 4 Queensland's water use, 2015–16 (megalitres)

1.2.3 Land use and population

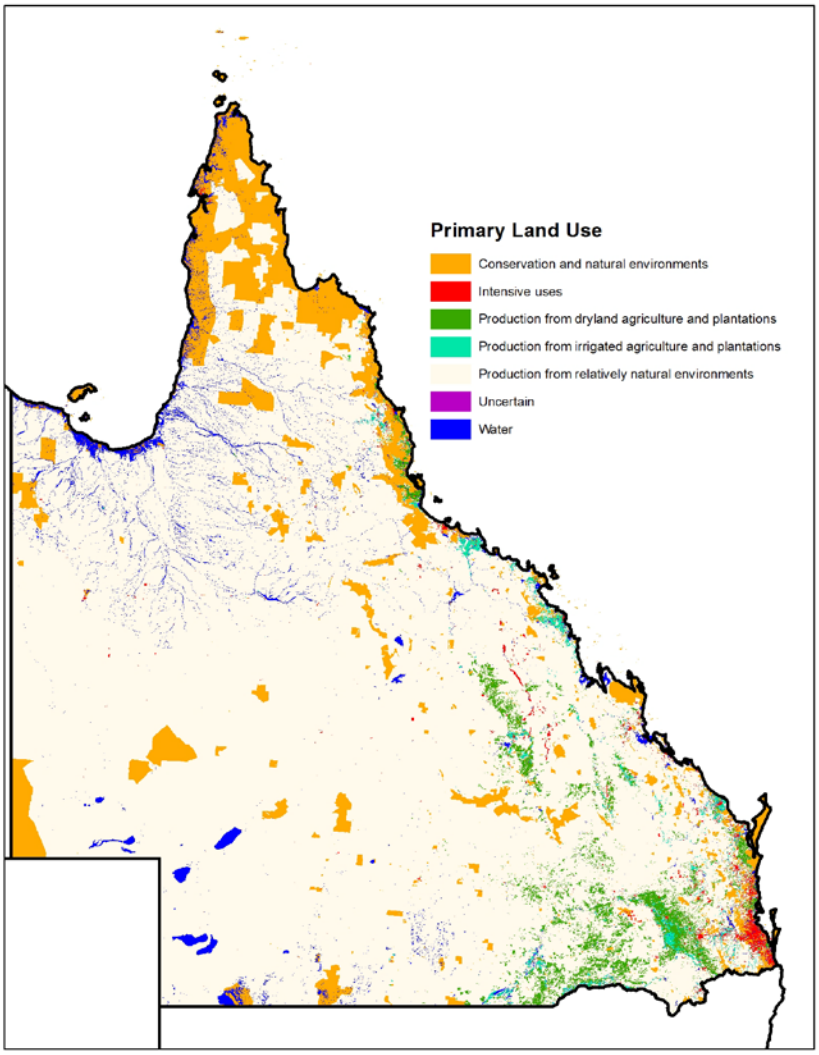
Queensland has a population of approximately 5 million people. Most live on the east coast, particularly around Brisbane. Population densities are very low across most of Queensland, with less than 1 person per square kilometre in most of the state and less than 0.05 people per square kilometre (1 person per 20 km^2) in inland regions (Figure 5). A useful source of information on Queensland's regions are the regional profiles on the Queensland Government Statistician's Office website (Queensland Government Statistician's Office, 2018).

Land use in Queensland is dominated by grazing (82%). Conservation areas (10%), water (e.g. lakes, dams, rivers, wetlands) (2.5%), dryland agriculture (non-irrigated cultivated crops) (2%) and irrigated agriculture (0.64%) are the next highest land uses (Queensland Department of Science, Information Technology and Innovation, 2014). Dryland and irrigated agriculture are concentrated around coastal areas and along the Brigalow Belt, whereas central and western Queensland is predominantly used for grazing (Figure 6). Intensive use, including mining, manufacturing, utilities, power generation, and commercial and residential, is limited to 0.59%. Gas production and supply infrastructure are part of the utilities subclass, which includes power generation and transmission, and water extraction and transmission. The utilities subclass makes up 0.53% of the intensive use class. Individual wells are part of the subclass, but the area they occupy is typically smaller than the minimum mapping unit, so they are not usually counted (Bureau of Agricultural and Resource Economics and Sciences, 2010).



Sources: Queensland Department of Natural Resources and Mines, no date b; Treasury Queensland Government, no date

Figure 5 Population density for local government areas across Queensland



Source: Queensland Department of Science, Information Technology and Innovation, 2014

Figure 6 Primary land use in Queensland

1.2.4 Shale gas and oil resources in Queensland

Currently, there is no active shale gas or oil industry in Queensland. However, a number of sedimentary basins (Figure 7) in the state have been identified as having prospective shale sequences for unconventional gas and oil exploration. Various Queensland basins and their shale resources have been investigated by:

- petroleum exploration companies
- the United States (US) Energy Information Administration and Advanced Resources International, Inc. (US Energy Information Agency, 2013)
- the United States Geological Survey (USGS) (Schenk *et al*., 2016)
- the Geological Survey of Queensland (Geological Survey of Queensland, 2016).

Table 2, compiled by the Geological Survey of Queensland (2017), provides a summary of Queensland shale gas and oil resources. It should be noted that petroleum estimates vary based on the assessment methods implemented, assumptions made and the level of certainty of available data. For example, some (e.g. Hughes, 2010; Inman, 2014) have criticised the assessment methods and assumptions employed by the US Energy Information Agency (2013) and labelled the results as too optimistic. The US Energy Information Agency (2013) reports resources at two levels: the 'risked resource in-place' is an estimate of the amount of gas or oil within the resource, applying some factors (the risks) of that resource being recoverable; the 'risked, technically recoverable' gas or oil resource is the portion of the risked resource that could technically be recovered based on current technology, industry practice and geologic knowledge. Resource estimates are updated as more data become available.

In the Cooper Basin (which crosses the Queensland – South Australia border), the US Energy Information Agency (2013) identified prospective shale intervals for gas in the Roseneath, Epsilon and Murteree formations within the Nappamerri, Patchawarra and Tenappera troughs. The Patchawarra and Tenappera troughs are located in South Australia, and the Nappamerri trough extends into Queensland. The risked resource in-place for the shales in the Cooper Basin was estimated at 325 trillion cubic feet (Tcf) of gas and 29 billion barrels of oil. The risked technically recoverable shale gas resource was 93 Tcf of gas and 1.9 billion barrels of oil. More recently, the USGS assessed the Cooper Basin for unconventional gas and oil resources (Schenk *et al*., 2016). This assessment covered a range of unconventional resources, which the authors referred to as continuous resources, including tight gas and oil, and gas hosted in deep coals. The USGS estimated mean totals for risked technically recoverable resources of 482 million barrels of oil and 29.8 Tcf of gas for the whole of the Cooper Basin (Schenk *et al*., 2016).

In the Maryborough Basin, the US Energy Information Agency (2013) investigated the Maryborough Formation (Cherwell and Goodwood mudstones). The risked gas in-place for the shales in the Maryborough Basin was estimated at 64 Tcf, and the risked, technically recoverable shale gas resource at 19 Tcf. The thermal maturity was regarded as too high for any shale oil to be present (US Energy Information Agency, 2013).

In the Georgina Basin (shared with the Northern Territory), the US Energy Information Agency (2013) conducted estimates for the western region covering the Dulcie Syncline (within the Northern Territory) and surrounding area, and an eastern region covering the Toko Syncline (straddling the border between the Northern Territory and Queensland) and surrounding area. Total risked shale gas in-place (in both synclines) was estimated at 67 Tcf, and the risked, technically recoverable shale gas resource at 13 Tcf. Total risked shale oil and condensate in-place was estimated at 25 billion barrels, and the risked, technically recoverable shale oil and condensate resource at 1 billion barrels.

The Bowen Basin, in central Queensland, has also come under investigation for its shale gas and oil potential. The basin extends over approximately 60,000 km^2 and has significant coalmining and CSG production. This basin contains thick sedimentary sequences including significant coal deposits, although little is known about the full hydrocarbon potential. For 2014–15, 64,401 barrels of oil were extracted from the Bowen and Surat basins from conventional resources. Some shale gas exploration has been conducted in the Bowen Basin, focusing on the Black Alley Shale. A best estimate of 'recoverable gas' (similar to the US Energy Information Agency's risked, technically recoverable resource, although it may not be directly comparable) of 97 Tcf from the Black Alley Shale was made (RFC Ambrian, 2013).

The Surat Basin, in southern Queensland (the basin crosses the border with New South Wales), is another active CSG-producing region. Limited exploration for deeper resources, including shale gas and oil, has taken place in this basin. However, the extent of shale gas and oil resources in the basin has not been formally assessed.

The Isa Superbasin in north-western Queensland has also been under investigation for its shale gas potential. Previous investigations have targeted the organic-rich (up to 11% total organic carbon – TOC) Riversleigh and Lawn Hill formations for assessment. Two exploration wells drilled in 2013 by Armour Energy confirmed the prospectivity of these shales, yielding the first lateral well in Australia to flow gas from a hydraulically stimulated shale formation, and confirmed gas desorption from Lawn and Riversleigh shale cuttings (Armour Energy, 2014). Currently, large volumes of gas have been estimated by Armour Energy, with a 'prospective resource' (similar to the US Energy Information Agency's risked resource in-place, although it may not be directly comparable) of more than 18.7 Tcf within Armour Energy's authority to prospect 1087 tenement alone (Armour Energy, 2015).

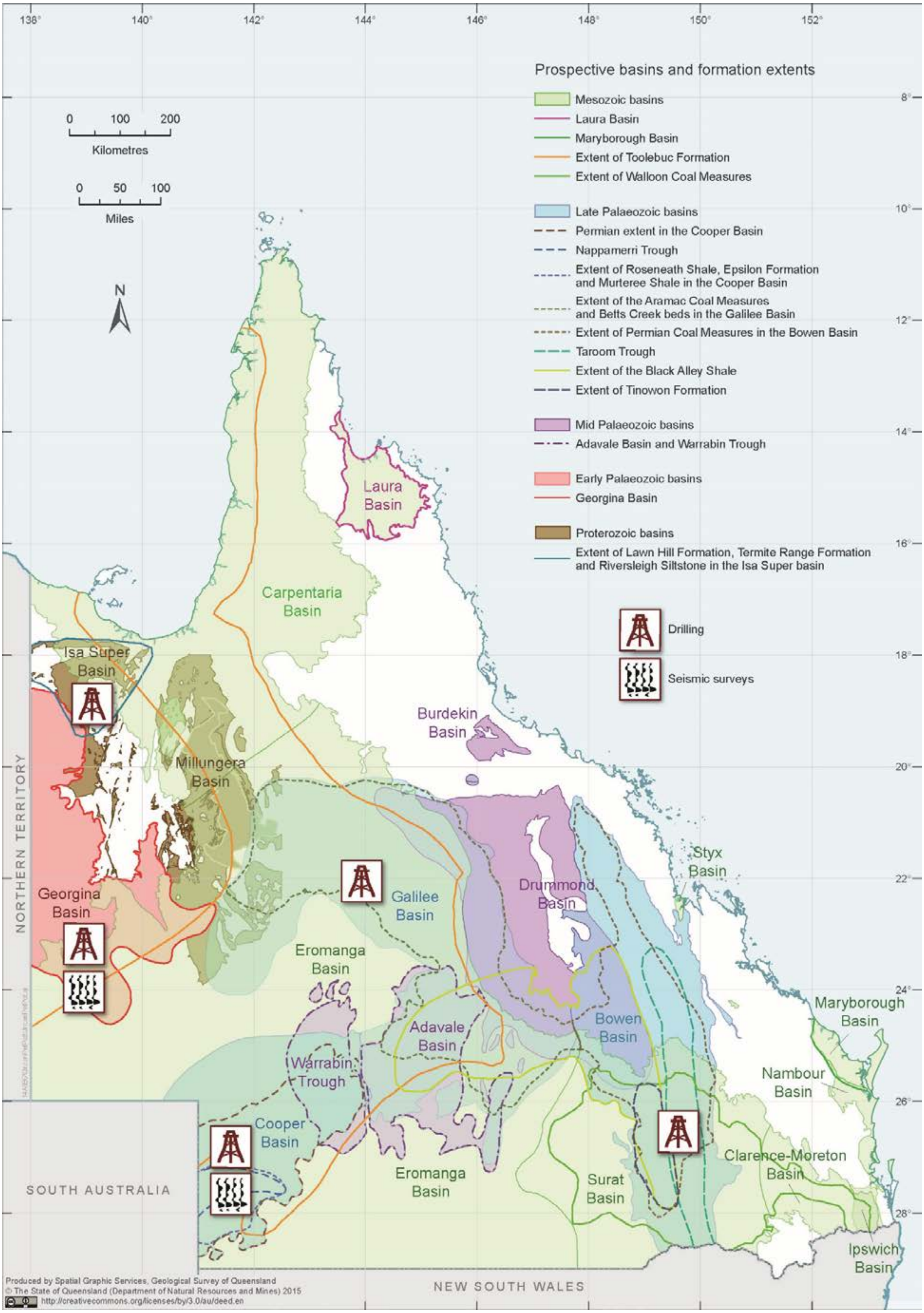
The Geological Survey of Queensland (2014) conducted a regional assessment of the Toolebuc Formation in the Eromanga Basin in central and northern Queensland. The aim was to assess the shale gas or oil potential of this formation, which is spatially extensive and relatively shallow, making it an easy exploration target. The thickness and the organic content of the formation were deemed comparable to successful North American hydrocarbon plays. Although studies suggests that there is a play fairway in the central Eromanga Basin, further exploration and research are required to determine the full potential of the Toolebuc Formation as an economic shale gas or oil target.

It is evident that Queensland has potential for significant shale gas and oil production. The Geological Survey of Queensland (2017) noted that some exploration has occurred in all of the basins mentioned in Table 2, and these contain either proven or speculative unconventional petroleum resources. In the future, further exploration and research need to be conducted on a range of different shale properties to further define the resources available and their potential to produce petroleum.

Table 2 Summary of Queensland shale gas and oil resources, compiled by the Queensland Department of Natural Resources, Mines and Energy

Basin	Formation	Environment	Thickness (m)	Top depth (m)	TOC (%)	Rv (%)	Resource target
Laura	Dalrymple Sandstone	Fluvio-deltaic	329–527	442–592	0.91–12.90	0.81	Shale gas or tight gas
Maryborough	Maryborough Formation	Marginal marine to estuarine	Up to 2,245	Outcrop to 865	Approx. 1.5	Up to 2.88	Shale gas or tight gas
Maryborough	Tiaro Coal Measures	Fluvio-lacustrine	6 to >430	Outcrop to 592	Coal	Up to 3.02	CSG or shale gas
Eromanga	Toolebuc Formation	Restricted marine	20–45	Outcrop to 1640	0.2–26.1	0.35–0.55	Shale oil or shale gas
Eromanga	Birkhead Formation	Fluvio-deltaic to lacustrine	Up to 580	Outcrop to 2,180	0.75–6.3	Up to 1	Shale gas
Eromanga	Westbourne Formation	Fluvio-lacustrine	70–130	Outcrop to 2,046	0.51–2.18	0.7–0.87	Shale gas
Eromanga	Poolowanna Formation	Fluvio-lacustrine	Up to 165	370–2,450	0.6–17.9	Up to 1.2	Shale gas
Cooper	Toolachee Formation	Fluvio-lacustrine	20–50	1,360–2,950	Up to 7.2	Up to 2.4	Shale gas or tight gas
Cooper	Roseneath Shale	Lacustrine	20–80	1,360–2,530	1.0	1–4	Shale gas
Cooper	Murteree Shale	Deep, freshwater lacustrine	Average of 50, up to 80	1,370–2,680	2.50	1–4	Shale gas
Cooper	Patchawarra Formation	Fluvio-lacustrine	Up to 550	1,375–2,990	Coal	Up to 3.6	Shale gas or tight gas
Bowen	Black Alley Shale	Marine to lacustrine	Up to 350	45–2,030	0.29–10.18	0.52–0.98	Shale gas
Galilee	Aramac Coal Measures	Fluvial and peat swamp	31–272	757–1,600	Coal	0.39–5.2	CSG or shale gas
Galilee	Betts Creek beds	Fluvial and peat swamp	50–210	Approx. 900	Coal	0.70–8.75	CSG or shale gas
Adavale	Log Creek Formation	Marine shelf	>755	Approx. 3,100	Up to 1.55	1.4–1.6	Shale gas or tight gas
Adavale	Lissoy Sandstone	Nearshore, shallow marine to restricted marine	Up to 470	Approx. 2,760	–	1.4–1.6	Shale gas or tight gas
Adavale	Cooladdi Dolomite	Lagoonal to back reef	Up to 85	Approx. 2,500	–	1.4–1.6	Shale gas or tight gas
Georgina	Arrinthrunga Formation	Carbonate and siliciclastic shelf	138–835	64–726	Up to 9.6	Up to 0.6	Shale gas or tight gas
Georgina	Inca Shale	Marine	Up to 133	Outcrop to 3,216	Up to 2.82	CCAI of 1–1.5	Shale gas or tight gas
Georgina	Thorntonia Limestone	Peritidal to restricted shallow marine	13–104	Outcrop to 1,960	Up to 8.7 in NT wells	–	Shale gas or tight gas
Georgina	Beetle Creek Formation	Marine	27 to >172	Outcrop to 1,018	0.19–1.51	CCAI of 1–1.5	Shale gas
Georgina	Georgina Limestone	Tidal shallow marine	>33.2 to 759	Outcrop to 2,457	EOM up to 2,000 ppm	TAI of 2.25–2.50	Shale gas or tight gas
Isa (Superbasin)	Lawn Hill Formation	Mid to outer shelf	Up to 2,200	Outcrop to 2,000	Up to 7	–	Shale gas
Isa (Superbasin)	Termite Range Formation	Turbidite fan	Up to 1,300	Outcrop to 2,500	Up to 8	–	Shale gas
Isa (Superbasin)	Riversleigh Siltstone	Mid to outer shelf	Up to 2,900	Outcrop to 4,500	Up to 8	–	Shale gas

CCAI = Conodont Colouration Alteration Index; CSG = coal seam gas; EOM = extractable organic matter; NT = Northern Territory; Rv = vitrinite reflectance; TAI = Thermal Alteration Index; TOC = total organic carbon
Note: Some formations are host to other unconventional plays (e.g. tight gas).
Source: Adapted from Geological Survey of Queensland, 2017



Source: Geological Survey of Queensland, 2017, supplied by Spatial Graphics Services, Geological Survey of Queensland. Licensed under http://creativecommons.org/licenses/by/3.0/au/deed.en.

Figure 7 Queensland sedimentary basins with shale gas and/or shale oil potential

Summary characteristics of prospective Queensland basins

Table 3 summarises the bioregions, water resources, land uses and other resource developments in the basins that are prospective for shale gas in Queensland. The basins in inland areas (Cooper, Eromanga, Adavale, Galilee, Georgina basins) are characterised by low rainfall, grazing as the dominant land use and limited development in general.

Table 3 Summary of Queensland context for basins prospective for shale gas and oil

Basin	Bioregion(s)	Average annual rainfall (mm)	Water resources	Land uses	Other resource development
Adavale	Mulga Lands, Mitchell Grass Downs	300–500	The overlying GAB; inland river systems (headwater of Murray–Darling)	Grazing. Very low population density	Conventional gas and oil
Bowen	Brigalow Belt	600–800	East coast–flowing river systems; local groundwater in the north; GAB; inland rivers in the south	Grazing, dryland agriculture, minor irrigated agriculture. Low population density	Coalmining, CSG
Cooper	Channel Country	Less than 300	The overlying GAB; inland river systems (part of Lake Eyre system)	Grazing, conservation. Very low population density	Conventional gas and oil
Eromanga	Channel Country, Mitchell Grass Downs, Mulga Lands	Less than 200 in the south-west, up to 600 in the north-east	GAB; inland river systems (headwaters of Lake Eyre system and Murray–Darling)	Grazing, conservation. Very low population density	Minor conventional gas and oil
Galilee	Brigalow Belt, Desert Uplands, Mitchell Grass Downs, Mulga Lands	300–600	GAB; inland river systems (headwaters of Lake Eyre system and Murray–Darling)	Grazing. Very low population density	Coalmining proposed
Georgina	Channel Country, Mitchell Grass Downs	Less than 300	The overlying GAB; inland river systems (headwaters of Lake Eyre system)	Grazing. Very low population density	None
Isa (Superbasin)	Northwest Highlands, Gulf Plains	600–1,000	Gulf-flowing river systems; local groundwater	Grazing. Low population density	Minerals mining

Basin	Bioregion(s)	Average annual rainfall (mm)	Water resources	Land uses	Other resource development
Laura	Cape York Peninsula	More than 1,200	East coast flowing rivers	Grazing, conservation. Very low population density	None
Maryborough	Southeast Queensland	1,000–1,200	East coast–flowing rivers; local groundwater	Dryland and irrigated agriculture, grazing. Moderate population density	None
Surat	Brigalow Belt, Mulga Lands	500–800	GAB; inland river systems (headwater of Murray–Darling); east coast–flowing rivers	Dryland and irrigated agriculture, grazing. Low population density	Extensive CSG development, minor conventional gas and oil, minor coalmining

CSG = coal seam gas; GAB = Great Artesian Basin

1.3 Queensland regulatory framework for shale gas and oil projects

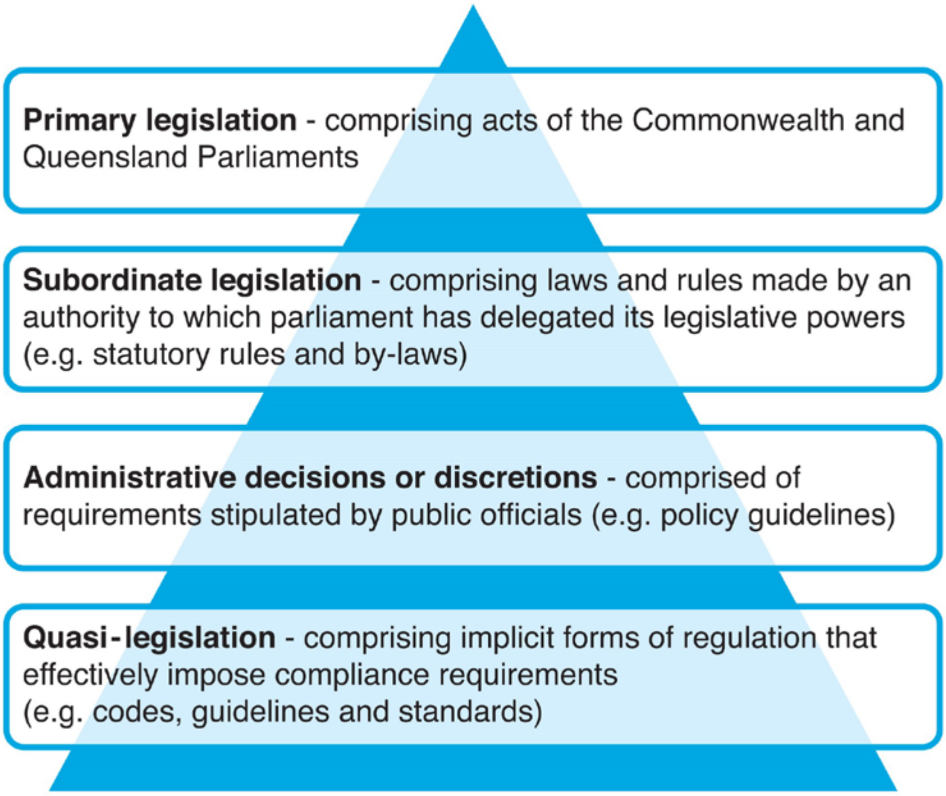
The regulatory mechanisms that currently apply to the development of CSG and conventional petroleum resources will also apply to shale gas and oil development. These regulatory mechanisms include primary legislation, subordinate legislation, administrative decisions or discretions, and quasi-regulations. The Queensland Competition Authority conducted a review of the regulatory regime applying to the CSG industry in 2014 (Queensland Competition Authority, 2014). Figure 8 shows the hierarchy of these mechanisms.

This overview considers the main legislation that applies to the production of petroleum resources, relating to impacts on the environment, public health and other industries (see Table 4). Legislation was not considered if it was related to other issues that involved workplace health and safety, industrial relations or corporations; nor were local government requirements considered.

The two most important pieces of legislation are the *Petroleum and Gas (Production and Safety) Act 2004* (P&G Act) and the *Environmental Protection Act 1994* (EP Act). The *Water Act 2000* (Water Act) is also important for the management of water use and mitigating impacts on water resources.

The P&G Act governs all onshore gas development in Queensland and it prescribes the different types of petroleum resource authorities that can be granted. Under the P&G Act, companies / developers can apply for a resource authority and if granted this gives them the rights to explore for and/or develop petroleum resources within a defined area (see section 1.3.1).

The EP Act regulates petroleum and gas activities in Queensland and defines things such as EA requirements, the environmental impact assessment process, and offences such as breaching conditions of an EA. An EA under the EP Act is required to carry out all petroleum and gas activities. The EA defines the environmental conditions and risk management requirements that must be complied with for a specific activity and development. The EA conditions are based on an assessment of the potential environmental impacts to environmental values that may occurring when carrying out the various project activities.



Source: Modified from Queensland Competition Authority, 2014

Figure 8 Overview of the hierarchy of regulatory mechanisms for coal seam gas, and conventional oil and gas resources in Queensland

1.3.1 Petroleum and Gas Authorities

There are a range different types of resource authorities that can be granted under the P&G Act. Each type of resource authority authorises a range of petroleum activities that can be carried out under that particular authority. A description of each type of resource authority is detailed below.

- Authority to Prospect (ATP) – allows the authority holder to explore, test, and evaluate feasibility of production for petroleum, oil, CSG and natural gas. Activities authorised under an ATP include drilling and hydraulic fracturing of exploration wells, although there are limitations on the total area of significant disturbance (1% of the tenure area).
- Potential Commercial Area (PCA) – allows the authority holder to retain part of an ATP beyond its term to provide extra time to commercialise the resource. Further drilling, hydraulic fracturing and testing of exploration and appraisal wells are authorised under a PCA.
- Petroleum Lease (PL) – allows the authority holder to explore, test and produce petroleum, oil, CSG and natural gas. Authorised activities include drilling and hydraulic fracturing of production wells, infield infrastructure and the production of gas and oil.
- Petroleum Pipeline Licence (PPL) – allows the authority holder to construct and operate a pipeline on an area outside an existing PL or ATP.
- Petroleum Facility Licence (PFL) – allows the authority holder to construct and operate a facility for processing, refining, storing or transporting petroleum on an area that is not already covered by a PL or PPL.

- Petroleum Survey Licence (PSL) – allows the authority holder to enter land to survey the proposed route or a pipeline or assess the suitability of land for a PFL. Only activities that have minimal impact on land are permitted.
- Data Acquisition Authority (DAA) – allows the authority holder to conduct limited geophysical survey activities and collect data on an area of land that is contiguous to but outside the area of an existing ATP or PL.
- Water Monitoring Authority (WMA) – allows the holder of an ATP or PL to comply with their obligations to make good any impacts caused to surrounding water bores as a result of the activities carried out on the ATP and/or PL.

The type of resource authority granted over an area determines what activities are permitted and the P&G Act has requirements for their safe conduct.

1.3.2 Overview of the regulatory pathway for petroleum projects

All petroleum resource projects follow a consistent regulatory pathway. In addition to legislation, there are regulations and other regulatory instruments, including codes (some are referred to in legislation) and policies. A full discussion of these is beyond the scope of this report. The high-level process for most petroleum resource projects is as follows:

- The project proponent applies for an ATP through a tender process. This process is regulated through the P&G Act, and administered by the Queensland Department of Natural Resources, Mines and Energy (DNRME). The project proponent must submit an initial work program as part of the tender process. The financial and technical capability of the applicant is also assessed. The holder of an ATP, or any other form of authority, is also referred to as the 'authority holder'.
    - An applicant for an ATP must obtain an environmental authority (EA) from the Queensland Department of Environment and Science (DES, previously the Department of Environment and Heritage Protection) before the ATP can be granted. This is a requirement of the P&G Act for the award of the ATP. The requirements for the EA are regulated by the EP Act and are discussed further in Section 1.3.3. The application for an EA is usually made once the application for the ATP has been lodged.
- The holder of an ATP must comply with the conditions of that authority and the EA, and obtain and comply with any other permits and authorities that may be needed under other legislation – for example, avoiding disturbance of sites with high Indigenous cultural heritage value in accordance with the *Aboriginal Cultural Heritage Act 2003*. If their work plan changes, the project proponent must amend their initial work program under the ATP, and may also need to amend the EA.
- The holder of an ATP may apply to have their ATP declared as a potential commercial area to allow them to continue to evaluate the potential for production and market for the resource. The relevant EA would have to be maintained and/or amended to reflect any planned activities.
- Once the project proponent has confirmed under their ATP that the petroleum resource is likely to be commercially viable, they can apply for a PL. This process is regulated through the P&G Act. The project proponent must submit an initial development plan as part of their application.
    - An applicant for a PL must obtain a new EA from DES, or amend an existing EA, for the development plan before the PL can be granted.
    - At this point, the project may trigger the Commonwealth *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) if it will impact on a matter of national

environmental significance. In this case, the project will need to be referred, an environmental assessment that meets EPBC Act requirements may be required, and the activities will need to be approved by the relevant Australian Government minister before they can proceed. The EPBC Act contains specific water triggers related to CSG and coalmining that do not currently apply to shale gas and oil developments, which are treated as any other activity.

  - The DES may require an environmental impact statement (EIS) to be prepared by the development proponent before the EA can be granted. The requirements for an EIS are regulated by the EP Act.
  - If the project is deemed to be a 'coordinated project' under the *State Development and Public Works Organisation Act 1971* (SDPWO Act), an EIS will be required. A coordinated project is one that has been identified by the Coordinator-General as involving one or more of
    - complex approval requirements, involving local, state and Australian governments
    - significant environmental effects
    - strategic significance to the locality, region or state, including for infrastructure, economic and social benefits, capital investment or employment opportunities it may provide
    - significant infrastructure requirements.
- The operator of a project must operate in accordance with the conditions of their PL and EA (which includes requirements for the rehabilitation of the project area before relinquishment). They must also meet the requirements of all other legislation relevant to their activities.

Table 4 Commonwealth and Queensland legislation relating to development of petroleum resources in Queensland

Legislation	Description	Administering department
Commonwealth legislation		
***Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act)**	Protection and management of nationally and internationally important flora, fauna, ecological communities and heritage places (matters of national environmental significance). Has a specific trigger related to water resources in relation to CSG development	Australian Government Department of the Environment and Energy
***Water Act 2007* (Water Act)**	Management of water in the Murray–Darling Basin. Catchments for this basin in Queensland are Paroo, Warrego, Condamine–Balonne, Moonie and Border Rivers. These catchments overlie the Surat Basin	Australian Government Department of Agriculture and Water Resources
***Native Title Act 1993* (NT Act)**	Recognition and protection of native title, and requirements for Indigenous land use agreements	Attorney-General's Department, Australian Government Department of the Prime Minister and Cabinet (Indigenous Affairs)
***Industrial Chemicals (Notification and Assessment) Act 1989* (IC Act)**	Notification and assessment of the use of industrial chemicals in Australia	Australian Government Department of Health (through the National Industrial Chemicals Notification and Assessment Scheme)
Queensland key legislation		

Legislation	Description	Administering department
Petroleum Act 1923	Regulates certain petroleum and natural gas activities. The *Petroleum and Gas (Production and Safety) Act 2004* supersedes this act, but an amended version of the *Petroleum Act 1923* was retained so that existing permit holders' existing rights were not lost	Queensland Department of Natural Resources, Mines and Energy
Petroleum and Gas (Production and Safety) Act 2004 **(P&G Act)**	Regulates petroleum and gas exploration tenure, safety, production and pipelines	Queensland Department of Natural Resources, Mines and Energy
Mineral and Energy Resources (Common Provisions) Act 2014 **(MERCP Act)**	Regulates land access for mineral and energy resource authority holders. Commenced on 27 September 2016	Queensland Department of Natural Resources, Mines and Energy
Environmental Protection Act 1994 **(EP Act)**	Regulates activities to avoid, minimise or mitigate impacts on the environment, and to protect Queensland's heritage places	Queensland Department of Environment and Science
State Development and Public Works Organisation Act 1971 **(SDPWO Act)**	Facilitates timely, coordinated and environmentally responsible development. Provides ability for Queensland's Coordinator-General to declare a project a 'coordinated project'. Coordinated projects require an environmental impact statement and a high level of public input	Queensland Department of State Development, Manufacturing, Infrastructure and Planning
Queensland – other relevant legislation		
Environmental Offsets Act 2014 **(EO Act)**	Regulates the requirements and management of environmental offsets in response to activities that cause a significant residual impact on prescribed environmental matters	Queensland Department of Environment and Science
Water Act 2000 **(Water Act)**	Regulates the sustainable management of Queensland's water resources and water supply, and the impacts on groundwater caused by the extraction of groundwater by the resources sector	Queensland Department of Natural Resources, Mines and Energy; Queensland Department of Environment and Science
Water Supply (Safety and Reliability) Act 2008 **(WS Act)**	Regulates interactions and direct impacts associated with drinking water supply	Queensland Department of Natural Resources, Mines and Energy; Queensland Department of Health
Waste Reduction and Recycling Act 2011 **(Waste Act)**	Regulates the production, reuse and disposal of waste materials	Queensland Department of Environment and Science
Regional Planning Interests Act 2014 **(RPI Act)**	Identifies and protects areas of Queensland that are of regional interest, and resolves potential land use conflicts. The Act protects living areas in regional communities, protects high-quality agricultural areas from dislocation, protects strategic cropping land, and protects regionally important environmental areas	Queensland Department of State Development, Manufacturing, Infrastructure and Planning
Public Health Act 2005 **(PH Act)**	Protects and promotes the health of the Queensland public. Allows for public health orders to be issued that require the removal or reduction of the risk to public health from a public health risk, or actions to prevent that risk from recurring. Allows for investigation of health complaints	Queensland Department of Health

Legislation	Description	Administering department
Radiation Safety Act 1999 **(RS Act)**	Protects people from health risks associated with exposure to particular sources of ionising radiation and harmful non-ionising radiation, and protects the environment from being adversely affected by exposure to radiation	Queensland Department of Health
Work Health and Safety Act 2011 **(WHS Act)**	Provides a framework to protect the health, safety and welfare of all workers at work. It also protects the health and safety of all other people who might be affected by the work	Queensland Office of Industrial Relations, which resides in the Queensland Department of Education
Gasfields Commission Act 2013 **(GFC Act)**	Establishes the Gasfields Commission, an independent statutory body with powers to review legislation and regulation, obtain and disseminate factual information, advise on coexistence issues, convene parties to resolve issues, and make recommendations to government and industry	The commission is independent, but administrative matters are handled by the Queensland Department of State Development, Manufacturing, Infrastructure and Planning
Fisheries Act 1994 **(Fisheries Act)**	Regulates the use of waterway barriers that may affect fish movement along a waterway	Queensland Department of Agriculture and Fisheries
Forestry Act 1959 **(Forestry Act)**	Regulates activities involving the clearing of forest products and access to quarry material on state land	Queensland Department of Agriculture and Fisheries
Biosecurity Act 2014 **(Biosecurity Act)**	Provides for weed, pest animal and contaminant management	Queensland Department of Agriculture and Fisheries (Biosecurity Queensland)
Nature Conservation Act 1992 **(NC Act)**	Regulates the protection of flora and fauna, as well as offset requirements	Queensland Department of Environment and Science
Aboriginal Cultural Heritage Act 2003 **(ACH Act)**	Regulates activities to protect Queensland's Indigenous cultural heritage values	Queensland Department of Aboriginal and Torres Strait Islander Partnerships
Queensland Heritage Act 1992 **(Heritage Act)**	Regulates activities to protect Queensland's heritage places	Queensland Department of Environment and Science
Transport Operations (Road Use Management) Act 1995 **(TO Act)**	Regulates the transportation of dangerous goods by road; manages road use impacts; issues directions on road use, including payment of compensation	Queensland Department of Transport and Main Roads
Planning Act 2016 **(Planning Act)**	Regulates developments not conducted under a relevant petroleum tenement	Queensland Department of State Development, Manufacturing, Infrastructure and Planning

1.3.3 Environmental authority

The EA is a critical component in the regulation of petroleum activities. The EA for a petroleum activity sets out the conditions for these activities. EAs are administered under the EP Act and are supported by a range of other regulatory instruments, including the Environmental Protection Regulation 2008 (EP Reg), policies (Environmental Protection (Air) Policy 2008, Environmental Protection (Noise) Policy 2008, and Environmental Protection (Water) Policy 2009), guidelines, procedures and eligibility criteria. These other regulatory mechanisms provide guidance on what must be included in an application for an EA, the level of performance required to be met under an EA, and approaches to management of impacts that would be deemed acceptable for an EA, as well as providing model conditions for an EA.

EA applications are assessed by the administering authority of the EP Act (DES). When approving an EA, the assessor must decide the extent to which the application achieves the environmental objectives relevant to the application. The environmental objectives and performance outcomes are set out in the EP Reg. The EP Act requires that any condition imposed in an EA be necessary or desirable to achieve the object of the EP Act, which is "*to protect Queensland's environment while allowing for development that improves the total quality of life, both now and in the future, in a way that maintains the ecological processes on which life depends (ecologically sustainable development)*". The conditions provide the administering authority's expectations for the management of potential environmental risks posed by petroleum activities.

An EA covers aspects of activities including:

- general environmental protection
- waste management
- protection of acoustic values
- protection of air values
- protection of land values
- protection of biodiversity values
- protection of water values
- rehabilitation
- well construction, maintenance and stimulation activities
- dams.

The mandatory regulatory requirements for an application to be properly made for the purposes of the EP Act are outlined in the guideline *Application requirements for petroleum activities* (Queensland Department of Environment and Heritage Protection, 2013b). Three types of EA applications can be made:

- standard application (s. 122 of the EP Act), where the activities meet eligibility criteria and are able to comply with all of the standard conditions for that activity. For petroleum activities, this would only apply for the exploration stage, for a petroleum survey licence or for a pipeline licence, and the eligibility criteria and standard conditions are contained in the *Eligibility criteria and standard conditions Petroleum exploration activities* (Queensland Department of Environment and Heritage Protection 2015b)
- variation application (s. 123 of the EP Act), where the activities meet eligibility criteria and one or more of the standard conditions for that activity need to be changed. For petroleum activities, this would only apply for the exploration stage
- site-specific application (s. 124 of the EP Act), where a standard or variation application cannot be made. The majority of petroleum activities progressing beyond the exploration stage would need to make a site-specific application. A site-specific application would need to be accompanied by detailed information about the proposed activities and their potential environmental impacts. This may include the preparation of an EIS according to the EP Act, or, if it has been deemed to be a coordinated project under the SDPWO Act, by the Coordinator-General.

Requirements for applications for EAs are detailed in s. 125 of the EP Act, as well as in the application guidelines (Queensland Department of Environment and Heritage Protection, 2013b). The application requirements vary depending on the type of application. In general, an application for an EA should have:

- identification of the environmental values in locations where the proposed petroleum activities will be undertaken and the potential impact of the proposed activities on these values
- a detailed risk assessment that includes identification of the risks to, and impacts on, environmental values caused by the activities within the project area and extending beyond to surrounding areas, including regional and cumulative impacts. As well as providing these risks and impacts, the authority holder is also required to provide background information and raw data used in conducting the assessment
- description of the management practices that will be used to control the risks of impacts on environmental values. The environmental protection commitments in the management plan should describe the incremental protection objectives and any performance indicators, the standards they will be assessed against, and control strategies that will be used to ensure that the objectives are achieved. Management plans for different environmental values (e.g. a noise management plan), as well as risk assessments and management plans for key activities (e.g. risk assessment and management plan for hydraulic fracturing), may also be required.

When a site-specific application is made for a resource project that is proposing to exercise its underground water rights, specific details on which aquifers are affected, the environmental values that will or may be affected, and strategies for avoiding, mitigating or managing such impacts must be provided (s. 126A of the EP Act).

There is a guideline for streamlined model conditions for petroleum activities (Queensland Department of Environment and Heritage Protection, 2016a). The guideline states that the 'streamlined conditions are outcomes-focussed, provide for transparency and consistency across the petroleum industry and will assist EHP (Department of Environment and Heritage Protection, now DES) in improving decision making time frames. These streamlined conditions provide guidance on the administering authority's expectations in managing potential environmental risks posed by petroleum activities'. The streamlined model conditions were developed collaboratively by the Department of Environment and Heritage Protection (now DES), industry and technical experts, and provide management approaches and constraints to protect environmental values acceptable to the administering authority. Their development included an evaluation of the risks to environmental values from petroleum production activities, and potential mitigation measures and constraints.

The streamlined model conditions cover general environmental protection, waste management, protection of acoustic values, protection of air values, protection of land values, protection of biodiversity values, protection of water values, and rehabilitation. Streamlined model conditions have not been developed for stimulation activities, although conditions are included in the guidelines that require a detailed risk assessment of these activities. Conditions for dams are contained in a separate guideline, *Structures which are dams or levees constructed as part of environmentally relevant activities* (Queensland Department of Environment and Heritage Protection, 2016c). The streamlined model conditions also exclude certain activities that were deemed to require site-specific assessment, including waste injection, reinjection of treated water, and releases to surface waters.

For a coordinated project, the EA must impose any conditions for the EA stated in the Coordinator-General's report for the relevant activity. Any other conditions imposed on the EA cannot be inconsistent with a Coordinator-General's condition.

The advanced stage of development of the CSG sector in Queensland is reflected by specific provisions in the EP Act and EP Reg. There are also policies, guidelines and approvals related to CSG, primarily focused on management of water. These regulatory instruments cover aspects of the EP Act, as well as requirements under other Acts, including the *Waste Reduction and Recycling Act 2011* (Waste Act) and the *Water Act 2000* (Water Act). For example, the streamlined model conditions for petroleum activities (Queensland Department of Environment and Heritage Protection, 2016a) include specific conditions around the handling of produced water from CSG projects. These conditions cover aspects of approvals under the Waste Act (Queensland Department of Environment and Heritage Protection, 2014a, 2014b), because produced water is considered to be a waste material, as well as aspects of the EP Act that define prescribed waste materials.

A plan of operations must be submitted by the authority holder before commencing petroleum activities. The plan must contain information about where the activities will be carried out, the actions that will be taken by the authority holder to comply with the conditions of the EA, the rehabilitation program and the proposed amount of financial assurance.

In summary, the EA for a petroleum project becomes the main regulatory instrument for setting the environmental approvals and conditions for a petroleum activity. The information required for an EA application (information about how the environmental risks will be managed, such as an EIS, and risk assessments related to specific activities such as stimulation activities) provides the assessment of potential impacts of the activity. The conditions in an EA set out the objectives of the proposed approaches for the management of these impacts.

1.3.4 Other state and Commonwealth legislation

Petroleum activities must also be conducted in a way that meet the requirements of all other legislation relevant to their activities. For shale gas and oil activities, the Water Act and Waste Act are important as they regulate impacts related to the taking of water for use in drilling and hydraulic fracturing and the disposal of wastewater after use respectively. Authority holders have limited rights to take water under the P&G Act. The EP Act and Chapter 3 of the Water Act sets out the requirements that the authority holder must meet in exercising these rights. Any other access to, or interference with, water resources requires authorisation under Chapter 2 of the Water Act.

There are a number of other pieces of legislation in Queensland that resource activities will have to comply with, including, but not limited to, those related to planning, fisheries, biosecurity (invasive species), public health, environmental offsets, cultural heritage and land access for resources development.

The EPBC Act may also be triggered if the proposed activities have the potential to impact on a Matter of National Environmental Significance (MNES). In this case, the project will need to be approved by the relevant Australian Government minister before they can proceed. Commonwealth legislation relating to water (management of water within the Murray–Darling Basin), native title, industrial chemicals, air emissions and greenhouse gases may also apply to shale gas and oil activities in Queensland.

The regulatory controls relevant to particular environmental values are described further in Part II of the report.

Part I Shale gas and oil resources and their extraction

2 Production of shale gas and oil resources

The development of shale gas resources in the US has had a significant impact on its energy market (Cook *et al*., 2013). The growth in this industry has largely been underpinned by advances in the technologies used to exploit the resources, primarily in drilling and hydraulic fracturing. By contrast, the development of shale gas and oil in Australia has seen limited exploration and very small-scale production as of April 2018. As a result, there is limited information on how these resources may be developed in the Australian setting. This uncertainty is exacerbated by differences in tectonic stress regimes in North America (extensional) and Australia (compressional and transpressional; Cooke, 2012). However, it is likely that the life cycle and technologies for the production of shale gas and oil resources in Australia will be similar to those used in the US.

This chapter starts with a description of shale gas and oil resources, then synthesises the descriptions of the life cycle and key technologies that are important to the production of shale gas and oil, as outlined in several recent studies (Broomfield, 2012; DMITRE, 2012; The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; New York State Department of Environmental Conservation, 2015a). In addition, a comparison is made between the development of CSG resources, in which Queensland has significant experience, and shale gas and oil resources. This chapter also provides an overview of water use in shale gas and oil projects, with reference, by way of comparison, to water use in CSG projects.

2.1 Geology of oil and gas from shale sources

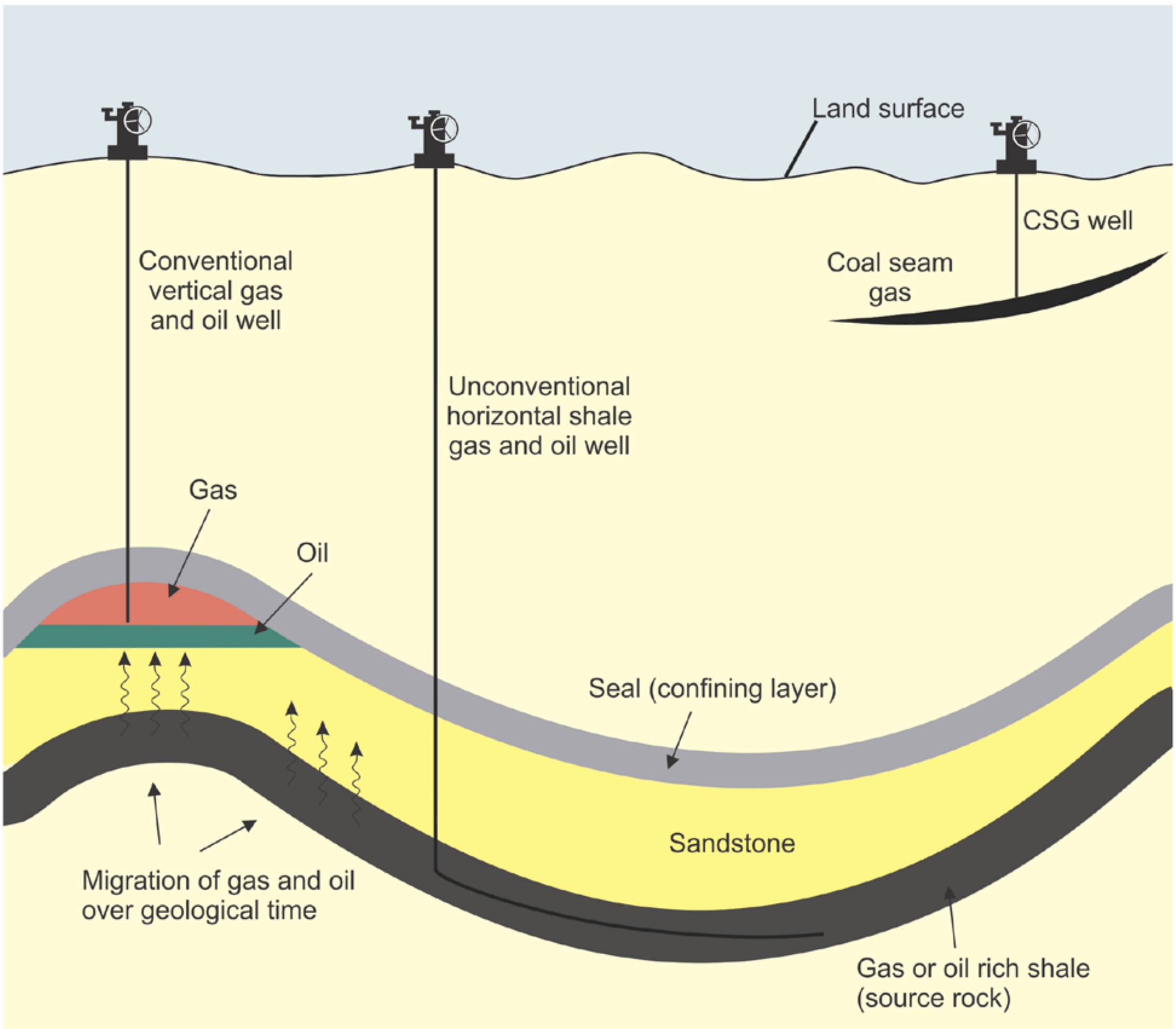
2.1.1 Petroleum resources

Hydrocarbons are the main constituents of crude oil and natural gas, which form through the transformation of organic matter in the subsurface. This transformation is a result of heat-driven reactions associated with temperature increases due to progressive burial. The transformation is referred to as thermal maturation. The degree of thermal maturity depends on multiple factors, including temperature, pressure and the duration of exposure to these conditions. In very general terms, organic matter will be progressively transformed into oil and then gas with increasing maturity. By usage, crude oil and natural gas are collectively referred to as 'petroleum' and are composed of a range of different chemical constituents. These constituents and the thermal maturation process are discussed in more detail in Appendix A.

In *conventional petroleum systems*, oil and gas are generated through, and partly expelled due to, various physical and chemical processes in an organic-rich source rock (Figure 9). The expelled petroleum migrates upwards through the sediment mass as a result of natural forces such as buoyancy (Figure 9). This migration through sedimentary sequences requires porous and permeable sedimentary rocks such as sandstones, fractured rock and permeable faults, to allow sufficient fluid flow (Hyne, 2012; Huc, 2013). Petroleum accumulates within porous reservoirs that are sealed or capped by impervious rock beds, salt domes or clay layers that prevent further upward migration. The geological elements needed to forecast petroleum volumes in conventional petroleum systems include source, reservoir, seal rock, and adequate generation, migration, and accumulation factors – these collectively comprise a petroleum system (Peters, Walters and Moldowan, 2004a). The identification of these elements allows the documentation, mapping and naming of petroleum systems. The petroleum in conventional systems is typically extracted by a combination of techniques that includes taking advantage of natural underground pressure gradients, the application of artificial pressure drive (through pumping and fluid injection), and even hydraulic fracturing to improve production.

In *unconventional petroleum systems*, oil and gas have accumulated in a reservoir that does not fit conventional reservoir models. Unconventional hydrocarbon sources were typically ignored for many decades, largely because of a lack of technology to allow them to be extracted economically. Unconventional hydrocarbon sources will become more important over time as conventional reserves are depleted (e.g. Huc, 2013). Typically, unconventional reservoirs require the application of different drilling and well completion technologies for hydrocarbons to flow to the surface. Examples of unconventional petroleum systems are:

- CSG – gas generated and reservoired in coal seams that requires pumping of water (reduction in water pressure) to enable the gas to flow to the surface
- shale gas and oil – gas or oil that has not been expelled from a source rock and requires artificial stimulation for extraction
- tight oil and tight gas – oil or gas that has been expelled from a source rock, has accumulated in a reservoir of very low permeability and requires artificial stimulation for extraction.



Source: Modified from http://www.eia.gov/oil_gas/natural_gas/special/ngresources/ngresources.html

Figure 9 Conventional and unconventional petroleum resources

What are gas and oil made from?

Natural gas and *crude oil* is mostly composed of hydrocarbons – compounds of hydrogen and carbon – which have formed from organic matter in the Earth's crust. Natural gas is made up of lighter hydrocarbon compounds that are in a gas form. Crude oil has heavier hydrocarbon compounds and form a liquid. There are some hydrocarbons, which have compound sizes between gas and oil called *condensates*. These compounds are a gas at the temperature and pressure conditions found underground, and *condense* to a liquid when at surface temperatures.

Natural gas contains methane and heavier hydrocarbon compounds (principally ethane, propane and butane) and condensates. The heavier hydrocarbon gasses, once separated from the rest of the gas, are collectively called natural gas liquids (NGLs). NGLs are valuable as they can be used in many applications, including transportation fuels, for heating, and as feedstock for petrochemical plants. Liquefied petroleum gas (LPG) in Australia is composed solely of propane. Condensates are also a valuable commodity because of their versatile utility as fuels or process chemicals.

All natural gas and crude oil resources can contain inorganic components, such as nitrogen, carbon dioxide, water and hydrogen sulphide. These components need to be removed as part of the processing of natural gas and crude oil before the hydrocarbons can be used.

Dry gas is predominately methane with a tiny proportion of heavier gasses and condensate.

Wet gas contains greater proportions of the heavier hydrocarbon gasses and condensates.

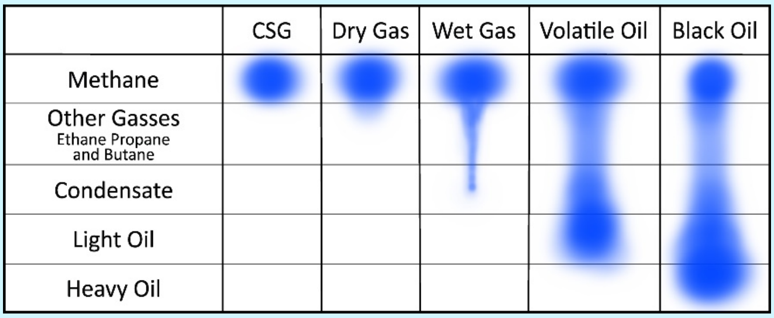
Volatile oil reservoirs contain condensate and light oils with a large gas component.

Black oil reservoirs contain heavy oils as well as lighter compounds, and can still have a significant gas component.

Shale gas and oil resources range in compositions from almost entirely gas to almost entirely oil and generally require separation of gas and liquids at the well head. The liquids may need to be further separated into condensate/crude oil and water components. A very dry shale gas resource may only need liquids separation at a gas processing plant.

Coal seam gas, by contrast, is typically mostly methane gas because of the formation processes.

Natural gas molecules have simple structures, but the larger molecules in condensate and crude oil can be more complex. As a result, the liquids produced from shale gas and oil resources may contain volatile organic compounds (VOC), polycyclic aromatic hydrocarbons (PAH) and benzene, toluene and xylene (known as BTEX compounds). Some of these compounds are known to be harmful, and must be handled appropriately. Coal seam gas does not contain these more complex hydrocarbons.



Components of natural gas and crude oil resources. For illustrative purposes only, proportions of different components not to scale. The compositions vary markedly for different resources.

A ‘petroleum play’ refers to prospects and fields that have similar geology and uses the characteristics of discovered petroleum resources to predict similar undiscovered counterparts (Peters, Walters and Moldowan, 2004b). Unconventional resource plays, especially shale gas plays, are generally characterised as having lower geological risk but higher commercial risk than conventional resource plays (Gray *et al*., 2007). The geological risk is generally perceived as being low because large continuous accumulations of sedimentary rocks such as shale serve as both the hydrocarbon source and reservoir (Klett *et al*., 2003). However, commercial risks are regarded as much greater, since the likelihood of economic production is a primary uncertainty (Gray *et al*., 2007). The commercial risk is, in part, resolved by drilling pilot (appraisal) wells to demonstrate whether the resource can be recovered economically using available engineering methods. Other commercial aspects, such as acreage availability and cost, commodity price environments, project execution timing, and rig count, also need to be considered (Gray *et al*., 2007).

In new regions, analogues are constructed mainly from established overseas resource plays, such as those in North America. However, although data are available from these established plays, their adoption in new areas may introduce additional uncertainty in the technical or commercial fit of a given analogue for a new target in a different geological environment (such as Australia), and this must be accounted for in the evaluation of a play or project. Other factors to consider include the availability of stimulation and extraction technologies, and equipment for evaluating and producing unconventional hydrocarbon resources.

2.1.2 Shale gas and oil resources

Shale gas and oil[2] are unconventional petroleum resources that are trapped within formations with very low porosity and permeability. Such units were previously only regarded as source rocks for conventional gas and oil resources. Recent drilling and completion technology developments have made shale an attractive target in petroleum exploration globally. The petroleum industry’s understanding of producing shale gas plays in North America is relatively advanced, with decades of work conducted in the Barnett, Haynesville, Marcellus, Woodford and Fayetteville shales (Ahmed and Meehan, 2016). Shale oil plays are still a fairly recent development, although proven North American plays, such as Bakken, Eagle Ford and Niobrara, exist. Globally, an estimated 10% of oil resources are in shale or other tight formations (US Energy Information Agency, 2013). The successful development of shale gas and oil in North America has resulted in worldwide interest in unconventional petroleum resources.

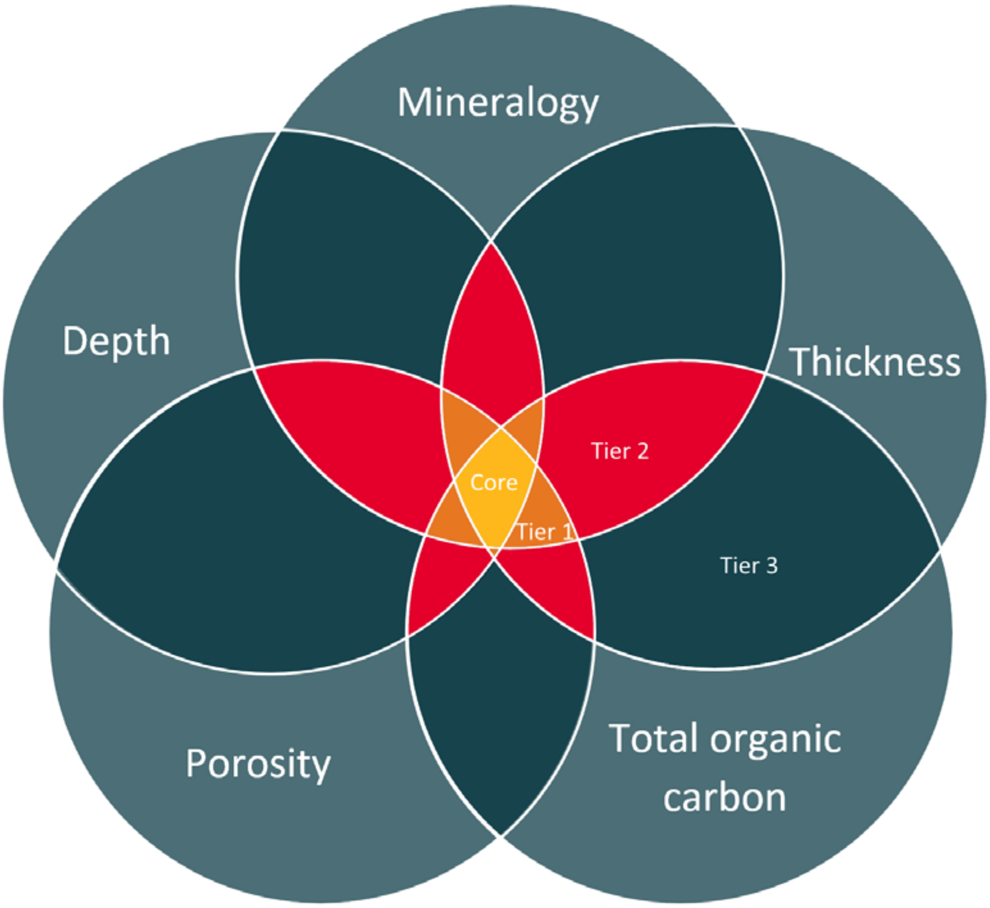
Shale is the most abundant sedimentary rock, and acts as both the source and reservoir in shale gas and oil resources. From a strictly geological perspective, shale is characterised as a finely layered, fissile sedimentary rock composed of fine-grained silt and clay-sized particles with a diameter less than 0.0039 mm (e.g. Zou *et al*., 2013). From an engineering perspective, however, shale constitutes any rock type containing at least 30% clay minerals (e.g. Farrokhrouz and Asef, 2013), including any mudrock. A characteristic of shales is that their matrix porosity is typically less than 10%, and permeability is less than 1 millidarcy (Zou *et al*., 2013).

Shale gas and oil form when the organic-rich rock enters the oil- or gas-generation stages of thermal maturation. The petroleum can be found in one of the following states:

[2] Shale oil pertains to the oil that naturally forms inside the pore spaces of the rock (shale) through the process of thermal maturation of organic matter (e.g. Huc, 2013). Oil shale, in contrast, refers to organic-rich shale that has no natural oil in its pore spaces because it is immature, but can yield substantial amounts of petroleum through destructive distillation (a process called retorting; e.g. Cook & Sherwood, 1991; Dyni, 2006). Tight oil refers to oil that has migrated to a very low permeability reservoir, which requires stimulation technology for economic flow to the surface (e.g. Huc, 2013).

- free oil and/or gas in pore spaces and fractures
- adsorbed gas weakly bonded by van der Waals forces to organic matter and clay particles
- dissolved gas in liquid hydrocarbons or water (e.g. Speight, 2012; Zou *et al*., 2013).

Shale gas can be either dry gas composed primarily of methane (60–95% volume per volume), or wet gas where methane is accompanied by considerable quantities of heavier gases (compounds such as ethane, propane and butane). The pore spaces in which the gas is held are up to 1,000 times smaller than those found in conventional sandstone gas and oil reservoirs. The gaps that connect the pores are smaller still. Shale gas and oil are referred to as a technology-driven resource because they rely heavily on technological advances (horizontal drilling, hydraulic fracturing) to achieve production. Furthermore, shale formations can exhibit various degrees of heterogeneity in their petrophysical and geochemical properties. The extraction of shale gas has traditionally been more difficult and more expensive than extraction from conventional reservoirs. However, as the US experience has shown, considerable technological innovation has significantly reduced production costs of shale gas. The most productive shale plays are defined by a range of geological parameters that involve mineralogy, porosity, permeability, thickness, depth, type and content of organic matter, and thermal maturation. Pore pressure is also important for driving hydrocarbons towards the well during production. However, shale plays vary with respect to these parameters. The aim in exploration is to define 'core areas' or 'sweet spots' where the optimal reservoir characteristics overlap (Figure 10).



Note: The figure shows the definition of a 'core' or 'sweet spot' area where the optimal geological and geochemical characteristics overlap. Different 'tiers' reflect shale sections with less optimal characteristics for exploitation.
Adapted from: Kimmeridge Energy, 2012

Figure 10 Gradational nature of shale plays

Several key factors determine whether a shale play is economically viable:

- total organic carbon (TOC) content, which is the total amount of organic material present in the rock expressed as a percentage of weight
- the organic matter type, which determines broadly whether the kerogen will produce gas or oil
- thermal maturity, which indicates the degree to which a particular shale unit has been suitably heated over time to produce gas or oil
- the thickness of the organic-rich shale unit, which indicates reservoir extent and the amount of gas stored
- porosity and permeability of the shale for petroleum holding capacity and sustainable gas production.

Each factor is discussed in greater detail in Appendix A.

2.2 Project life cycle

The project life cycle for shale gas and oil is very similar to that of other petroleum resources, (i.e. exploration, appraisal, development, production, and finally site closure and rehabilitation). The exact time line and activities for a given project will vary, depending on the nature of the resource, and economic factors such as commodity prices and other financial considerations. The most significant differences between shale gas and oil resources and other petroleum resources are the lateral extent of the resource and the very low permeabilities, which require a large number of wells to be drilled, and the hydraulic fracturing of the reservoir to allow adequate production rates.

2.2.1 Exploration

Before exploration can commence, a petroleum project proponent must apply for an ATP under the P&G Act, and obtain an EA under the EP Act and any other permits required under relevant legislation. An individual project area may be covered by a single ATP or by several. An ATP covers exploration up to the point that a resource has been discovered and defined such that commercial production of oil and gas is likely. Typically, the exploration phase for a project will be around 3–5 years, but this timing depends on a range of factors, including the nature of the resource and external economic factors (primarily the price of oil and gas, and access to markets).

The aims of the exploration phase of a project are to discover and define the extent of the resource, and to characterise this resource. The key activities conducted during the exploration phase include the following:

- Analysis of pre-competitive data (data provided by government agencies) and company reports from previous explorers. Evaluation of these data is critical for determining what additional data need to be collected.
- Gathering of geophysical data. The primary type of geophysical data collected for shale gas and oil exploration is seismic survey data. Seismic surveys allow images of the subsurface to be constructed by measuring the reflection of seismic energy from the subsurface. The seismic energy is waves of elastic energy travelling through rock, comparable to sound waves in air, and is created by a controlled seismic energy source. The reflected seismic energy is detected by an array of receivers at the surface. Seismic surveys can be conducted in 2D, along a long line extending tens to hundreds of kilometres, or in 3D, covering an area of several hundreds of square kilometres. Seismic surveys are generally low impact but may require clearing of single-use access tracks, although existing access routes are used wherever possible. Other types of geophysical surveys

include magnetic and gravity surveys. These surveys can be conducted using airborne or land-based methods requiring single vehicle access.

- Drilling of exploration wells. To test for the presence of a resource, wells are drilled to intersect the subsurface formations where oil or gas are predicted to be. Drilling methods used for shale gas and oil are described in Section 2.5.1. Most exploration wells are drilled vertically and test the targeted formations for the presence of an oil and/or gas resource. Additional information required to characterise the resource will also be collected, including the permeability and porosity of the target and overlying formations; the amount of oil and gas present; TOC content; temperatures and pressures; geomechanical properties such as strength and elasticity; and the presence, quantity and chemistry of water within the formations intersected. These data may be collected from physical samples (obtained via core drilling), wireline logging or formation testing.

The number of wells drilled during the exploration phase is likely to be in the order of tens for a typical ATP. The maximum ATP size in Queensland is around 8,000 km² (a maximum area of 100 'blocks', with each block having a size of 5 minutes of latitude by 5 minutes of longitude).

During the exploration phase, production testing may also be conducted on some wells to confirm how productive the resource is likely to be. Such wells are likely to be hydraulically fractured so that the productivity of the resource can be tested. Horizontal drilling may also be conducted to allow a greater area of the target formation to be tested. Gas produced during testing is normally flared because it is usually not commercially or technically feasible to capture it during the exploration phase. Liquid hydrocarbons are typically captured and transported to a refinery for processing.

Typical infrastructure and activities required to support the exploration phase includes preparation of well pads; construction of access tracks to the well pads; laydown yards for supplies; collection, storage and treatment of water for drilling fluids and hydraulic fracturing; and, in some cases, establishment of temporary accommodation for drilling crews.

In addition to activities directly related to resource exploration, the project proponent will often also need to conduct surveys (e.g. cultural and heritage surveys, environmental surveys), and develop relationships and share information with the local community before commencing any other work. The requirements for these additional activities are set out in the regulatory framework governing the development of these resources (see Section 1.3). As a minimum, the project proponent needs to ensure that the areas potentially impacted by the work program during this exploration phase have been appropriately assessed. Further work may be conducted to collect data on these cultural, heritage and environmental values to allow planning of any subsequent development.

2.2.2 Appraisal

Once a resource has been discovered through the exploration phase, further work is conducted to define the resource during the appraisal phase. The aim of this phase is to increase the certainty of the resource definition to inform a final investment decision on whether to develop the resource. This decision heavily depends on a range of external factors.

The appraisal phase typically takes 5–10 years. The transition from exploration to appraisal is somewhat arbitrary, and the combined duration of the exploration and appraisal stages could be 5–10 years.

The activities in the appraisal stage act as an extension to those in the exploration phase, and focus on characterising the resource and its extent. An important aspect of the appraisal phase for unconventional petroleum resources is to confirm the engineering methods necessary for viable commercial production of oil and/or gas from the targeted resource.

Key activities during the appraisal phase include the following:

- Drilling of appraisal wells and/or pilot production wells to further define the extent and characteristics of the resource and to test well configurations for production, including horizontal drilling. The wells are likely to be hydraulically fractured, with multiple hydraulic fracture stages in each well. The number of wells drilled at this stage are typically in the order of the low tens per tenement.
- Extended production tests, which can take many months, are also carried out. The aim of the production tests is to define the estimated ultimate recovery for each well, which is an important parameter in defining the technical and commercial viability of producing from the resource. Gas produced during this testing is normally flared as it is usually not commercially or technically feasible to capture it during the exploration phase. Liquid hydrocarbons are captured and transported to a refinery for processing.
- Additional geophysical surveys may be conducted to better define extent of the resource.
- In addition to defining the resource, the project proponent may also seek to gather information necessary for developing ancillary infrastructure needed for the project. This might include defining water resources, selecting suitable sites for processing facilities, access routes for equipment, and access routes for pipelines.

The activities of the appraisal stage require infrastructure similar to that outlined for the exploration phase (such as well pads, access roads, laydown yards and water access). Infrastructure developed during the exploration stage may be reused. More data collection on cultural, heritage and environmental values is also likely to allow planning of the development phase (see Section 2.2.3).

2.2.3 Development

Once the final investment decision to develop the resource has been made after appraisal, the project proponent must apply for a PL, and obtain an EA and any other permits required under relevant legislation to move into a development phase. During this phase, the first stage of the production well field and associated infrastructure are developed to supply gas to market. This is a period of intense activity. A large number of wells need to be drilled and hydraulically fractured, and a significant amount of supporting infrastructure needs to be developed. Hydraulic fracturing is described in Section 2.5.2.

The duration of this phase is highly dependent on the level of pre-existing infrastructure in the area and the need to install new infrastructure, including pipelines to transport produced gas to market, existing processing facilities and supply lines for consumables. Time frames of two or more years are likely for the initial development phase. The development and production phases are then likely to overlap as production of gas and/or oil commences and the scale of the operation grows over a period than can span a decade or more. Similarly, further appraisal and exploration are likely to be under way in surrounding areas to prove up resources for long-term development.

Activities at this phase include the following:

- Drilling and hydraulic fracturing of development wells. Once completed, development wells produce oil and/or gas to supply to market. The number of wells drilled will depend on the average production rate for each well, the average rate at which production declines for each well, and the required overall production levels for the project. Lewis (2013) provides an example for a well field capable of an annual production of 50 petajoules (PJ) of gas per year (for comparison, the Queensland CSG industry is currently producing more than 700 PJ/year). In this example, approximately 90 wells are required in the first year and 50 wells in the second. This amount of drilling is expected to require five drilling rigs working continuously for the first year.

- Development of field infrastructure. To support these drilling activities and resulting production, significant infrastructure is required, including
    - access roads
    - gathering networks (pipelines) for delivery of produced gas and oil to processing facilities
    - processing plant to allow the separation of different components of the gas/oil and impurities such as carbon dioxide and hydrogen sulfide
    - compression facilities for the delivery of gas to transmission pipelines
    - power supply for processing plant, compression stations and other infrastructure
    - water supply (water bores, storage dams and treatment facility)
    - storage areas, workshops, administrative offices, and camps for drilling and construction crews.

The maximum size of a PL is around 240 km^2 (a maximum area of 75 ‘sub-blocks’, with each sub-block having a size of 1 minute of latitude by 1 minute of longitude). It is likely that a shale gas or oil development project would comprise several adjoining PLs.

2.2.4 Production

Once development has been completed to the point where produced oil and gas are getting to market, the project enters the production phase. Unlike conventional petroleum resources (and similar to CSG resources), the decline in production from individual wells requires continual replacement of production wells throughout the life of the project. The 50 PJ example gas field discussed in Section 2.2.3 would require an average of 30 wells per year to be drilled over the 20-year life of that project (Lewis, 2013). In addition to drilling new wells, the production from existing wells can be improved by ‘working over’ the well. A workover involves cleaning out the well and potentially restimulating the reservoir (e.g. hydraulic fracturing).

During production, the main activities include:

- workover of production wells (to improve productivity)
- infill drilling and hydraulic fracturing to replace depleted production wells
- construction of additional pipelines for gathering networks
- production and processing of gas/oil
- plugging and abandoning of depleted wells, and rehabilitation of associated well pads.

The life of a shale gas or oil project is likely to be several decades.

2.2.5 Rehabilitation

Once production has been completed, the wells must be plugged and abandoned; the processing plants, compression stations and pipelines must be decommissioned (if they cannot be used for other resources); and the sites must be rehabilitated. The rehabilitation must comply with requirements of the PL and EA, and satisfy any other regulatory approvals obtained for the project.

The plugging and abandoning process is likely to be ongoing because early-producing wells will be rehabilitated while production continues elsewhere. Plugging and abandoning are described in Section 2.5.1.

Activities during the rehabilitation phase are likely to include:

- decommissioning, plugging and abandoning of wells; and rehabilitation of well pads
- decommissioning and rehabilitation of pipelines and pipeline access corridors
- decommissioning of the processing plant and compression stations, and rehabilitation of associated sites
- decommissioning of associated infrastructure, including power and water supplies, laydown yards, workshops, administrative offices, workers' accommodation and access tracks/roads.

Few shale gas and oil projects have reached this phase in their life cycle, although individual wells have been abandoned.

2.3 Water use and production

One of the key aspects of shale gas and oil developments is the use and production of water. Shale gas and oil developments are likely to use significant volumes of water, primarily for hydraulic fracturing. The amount of water used varies depending on local conditions, but is likely to be between 5 and 20 ML per well (King, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; US Environmental Protection Agency, 2016a). The current preference in North America has been to use fresh or low-salinity water for hydraulic fracturing because water with high salinities may cause damage to surface equipment and to the targeted formations. Although these volumes of water are large, the studies note that the amount of water used in a shale gas development is very small compared with other uses of water such as agricultural, public supply, mining and industrial. Water for hydraulic fracturing is required at the well over a short period of only a few weeks (US Environmental Protection Agency, 2016a). This high rate of delivery to the well may require a large number of truck movements over a short period of time, or high rates of water extraction from a local water resource.

Of particular relevance are the findings of Hawke (2014) for the Northern Territory, which is an arid environment similar to western Queensland. Hawke found that 'unconventional gas extraction has water requirements for drilling and hydraulic fracturing that are small in the context of many other licenced water uses, but which need to be managed carefully to ensure sustainability at a local or catchment/aquifer scale' (Hawke, 2014, p. xv). Water that is too saline for livestock or other uses may be suitable for hydraulic fracturing, which may reduce competition for water resources. New methods are under development that allow saline water or waterless fracturing methods, using gels, or carbon dioxide or nitrogen gas foams; however, these technologies are still emerging.

Shale gas and oil wells produce flowback water and produced water as part of their operations. Flowback water is the hydraulic fracturing fluid that has been injected into the well returning to surface. The flowback water contains the chemicals added to the hydraulic fracturing fluid (see Section 2.5), as well as components present in the formation water, including salts (i.e. the water will have high salinity); ions such as barium, strontium and bromine; low concentrations of heavy metals; organic matter; and naturally occurring radioactive materials (NORM) from the rock and formation water (Cook *et al*., 2013). The exact composition is location dependent, which will dictate the level of care needed in handling this flowback water. The amount of flowback water produced by each well is also highly dependent on local conditions, with 25–75% of the volume injected during hydraulic fracturing returning to the surface (Cook *et al*., 2013). The initial composition will be close to that of the hydraulic fracturing fluid but will become gradually more dominated by the formation water.

During long-term gas and oil production, water is also produced. The volumes of produced water are quite low for shale resources. Cook *et al*. (2013) give an example from a North American study for a shale gas development, which assumes an average of 0.285 ML of produced water per well per year, compared with 7.6 ML of flowback water produced per well after hydraulic fracturing. This produced water is formation water and will have high salinity due to its resident depth; it may contain ions such as barium, strontium and bromine; low concentrations of heavy metals; organic matter; and NORM. The amount of flowback and produced water depends on local geological conditions and the production methods employed.

One of the key differences between CSG and shale gas and oil developments is the use and production of water. Cook *et al*. (2013, p. 24) indicate that the amount of hydraulic fracturing fluid required for shale gas may be 'an order of magnitude larger than that for coal seam gas depending on well depth and extent of horizontal drilling'. The volume of produced water, even considering flowback water, is significantly less for shale gas than the amount produced over the life of a CSG project (Cook *et al*., 2013). The Queensland Government collects data on the amount of water produced from petroleum wells (Queensland Department of Natural Resources and Mines, no date d). According to these data, the total production of water from Queensland's CSG resources in the 2016—17 financial year was 56,615 ML from around 5,542 wells, representing an average of around 10.2 ML per well per year of produced water. In comparison, the conventional petroleum sector produced 6,440 ML of produced water in the 2016—17 financial year from around 632 wells. This represents an average of around 10.2 ML per well per year of produced water, produced alongside natural gas, liquefied petroleum gas, condensate and crude oil. The volumes of produced water per well for CSG and conventional petroleum in Queensland being the same for this time period is coincidental.

It is important to note that there will be much variation between CSG wells. The rates of water production will also decline over a well's life. As a result, the average production of water per well over the life of the CSG sector is likely to be less than the current average. Similarly, the exact amounts of flowback water and produced water for shale gas and oil resources in Queensland are highly uncertain.

2.4 Comparison with coal seam gas, and conventional gas and oil

The development process for shale gas and oil in Queensland is expected to have many similarities to the development process for CSG and conventional resources. Table 5 provides a comparison of key geological characteristics of CSG and shale gas and oil resources, and their development. Table 6 compares the key activities at different phases of CSG and shale gas and oil projects. Table 7 provides a comparison of key technologies and engineering methods of drilling and hydraulic fracturing.

The primary similarity between CSG and shale gas and oil resources is that the reservoir is hosted within the source rock (see Section 2.1). Both these resources have large spatial extents and require a large number of wells to extract the resource (compared with conventional petroleum resources).

The primary contrast between CSG and shale gas and oil pertains to the nature of the host rocks. The gas in coal seams is held in place by hydrostatic water pressure within the coal seam, and the water in the seam must be removed to allow the gas to flow. As a result, CSG resources typically produce large volumes of water. Coal seams typically have considerable permeability, which allows this water and gas to be produced with no, or moderate amounts of, hydraulic fracturing. In contrast, the gas and oil in a shale are adsorbed into the shale, or held in pore space and fractures within the shale, essentially trapped because the shale has inherently low permeability. The shales *must* be hydraulically fractured to provide the permeability necessary to allow the gas to be produced. Only low volumes of water are produced.

The primary similarity between shale gas and oil resources and conventional petroleum resources relates to the processing facilities required for the produced gas and oil. The hydrocarbons in these resources have been produced by thermogenic processes (heat driven) and can range from liquid hydrocarbons, or oil, through to dry gas. The gas and oil may also contain components such as carbon dioxide and hydrogen sulfide. As a result, the oil and gas produced from shale resources will require the same processing used for conventional gas and oil production. This contrasts with CSG, which is typically the result of biogenic processes (microbial activity) that produce gas dominated by methane, requiring different processing facilities.

As described in Section 2.1, shale resources may contain only oil, only gas, or a mixture of both. The exact composition of hydrocarbons in a shale resource can have a significant impact on the economics of developing these resources, and on the related infrastructure and development process. Liquid hydrocarbons have greater economic value and higher density than gas. It can be economically feasible to collect and store liquid hydrocarbons at an individual well, whereas gas requires network pipelines. This can influence the scale and rate of development of a project.

The life cycles for shale gas projects and CSG projects will be quite similar, following the exploration, appraisal, development, construction, production and rehabilitation phases. The CSG industry in Queensland underwent a period of rapid growth during the past five years, with the number of wells producing gas increasing from around 1,000 to just over 5,000 between 2013 and the middle of 2016 (Queensland Department of Natural Resources and Mines, no date d). This rapid growth was necessary to supply the three LNG export facilities at Curtis Island, and was only possible because of the previous two decades of exploration and appraisal of CSG resources. The rate of growth of development of shale gas and oil resources in Queensland may not be as rapid, because these resources are likely to feed into existing markets and use existing infrastructure.

A range of technical and economic factors will influence the scale of development. There will be a minimum size for the development of a shale gas field, which is influenced by the economics of setting up surface infrastructure such as gathering networks, processing facilities and transmission pipelines (DMITRE, 2012; Lewis, 2013). Where these facilities already exist, the scale of initial shale gas and oil projects may be quite small. For example, in south-west Queensland, individual shale gas wells drilled into the Cooper Basin could supply gas to the Ballera processing facility using existing infrastructure. On the other hand, development in the Georgina Basin would need to be at a larger scale, because this area currently has limited infrastructure. Another factor that will influence the scale of development is the number of wells required to produce the desired volume and rate of gas supply over the life of a project. Although this is a characteristic of the resource and the engineering used to develop it, and is difficult to predict, it is likely that the number of wells required to produce a certain volume of gas will be similar to that required for CSG. The initial production rate of CSG is low until the seam is dewatered enough to allow gas to flow. Shale gas wells may have higher initial production rates than CSG wells but are likely to decline more quickly. Overall, shale gas wells will most likely have higher production rates and produce a higher recovery of gas per well than CSG.

Table 5 Key geological characteristics of coal seam gas and shale gas and oil, and their development

Characteristic	CSG	Shale gas and oil
Locations (Queensland)	Currently producing in the Bowen and Surat basins. A number of other basins are subject to exploration (e.g. Eromanga Basin, Cooper Basin) or appraisal (Galilee Basin)	Currently no producing fields. Several basins (e.g. Georgina Basin, Cooper Basin, Eromanga Basin, Bowen Basin, Isa Superbasin) are subject to exploration
Hydrocarbon source	Gas produced through a mix of thermogenic and biogenic processes. Thermogenic formation as a result of coalification (of mostly terrestrial organic matter). Biogenic formation early in burial, or through the introduction of microbes by meteoric groundwater and subsequent alteration (secondary biogenic gas)	Mostly thermogenic generation through thermal maturation of organic matter that was deposited within the shale-forming sediments. Biogenic shale gas can also occur in shallower settings during early diagenesis. Organic matter types in shales originating from marine, lacustrine or terrestrial sources. Mixed organic sources also occur
Hydrocarbon occurrence	Gas is generated and trapped within coal bodies; the majority is adsorbed to the coal matrix, and a lesser amount is stored as free	Oil and gas is generated and trapped within shale of low porosity (5–10%) and permeability (10 nanodarcy to 10 microdarcy).

Characteristic	CSG	Shale gas and oil
	gas or dissolved gas in cleats, fractures and other openings in the coal. Source acts as the reservoir. Gas is held by water pressure within the coal structure	Source acts as the reservoir. Gas occurs freely in pores or fractures, dissolved in liquid hydrocarbons or water, or adsorbed to the surface of organic matter and clay particles. Free oil in shale is generated and stored in pores and fractures
Hydrocarbon types	Mostly methane (dry gas; CH_4) with minor amounts of carbon dioxide (CO_2), hydrogen sulfide (H_2S), nitrogen (N_2), helium (He) and argon (Ar). Can also contain traces of (wet gas) ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}). Unless coal is in close contact with an intrusive igneous body, amounts of CO_2 are minor. Presence of CO_2 makes production less economic	Ranges from dry gas (CH_4) through to black oil. Minor (and variable) amounts of other gases such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), nitrogen (N_2), helium (He) and the noble gases also occur
Typical depths	Depth intervals of 250–1,000 m are favoured to develop hydrostatic pressure and promote well production. Shallower depths can result in degassing, while in deeper settings the permeability is often too low to allow sufficient gas flow	Commonly found at depths of 1,000–4,000 m
Resource thickness	Individual seams may be metres to tens of metres thick. Total resource thickness can be up to hundreds of metres, with coal interbedded with other rock types	Individual shale layers range from metres to hundreds of metres. Total resource thickness can be up to hundreds of meters, with shales interbedded with other rock types
Resource extent	CSG resources can cover hundreds to thousands of square kilometres	Shale gas and oil resources can cover hundreds to thousands of square kilometres
Relationship with aquifers exploited by other industries	Highly dependent on local geological conditions, coal seams themselves may be aquifers, may be in direct contact with exploited aquifers, or may be separated vertically by hundreds of metres	Highly dependent on local geological conditions. The depth of most shale gas resources means that they will typically be separated vertically from exploited aquifers by hundreds to thousands of metres

CSG = coal seam gas
Note: This information should be considered as general in nature. Local geology, variations in practices between operators, and evolving technologies mean that the observations made here will not cover all cases. The nascent stage of shale gas and oil developments in Australia also means that the observations can only be inferred from international experience.

Table 6 Key characteristics of phases in the life cycle of coal seam gas and shale gas and oil projects

Resource project phase	CSG	Shale gas and oil
Exploration		
Data gathering	Review of publicly available geoscientific data compiled by government agencies (e.g. Geological Survey of Queensland) and statutory company reports	As for CSG
Geophysical surveys	May include seismic, magnetic or gravity surveys. 2D or 3D seismic surveys may be conducted over hundreds of line kilometres or many hundreds of square kilometres, respectively	As for CSG, except that seismic surveys are more likely to be conducted for these resources because of their depth
Drilling	Exploration wells are drilled to determine the presence and extent of a resource. Several tens of wells may be drilled on an ATP. The well spacing would around 1 well per 10 km^2	As for CSG, although the number of exploration wells may be smaller because of the higher costs of drilling wells that are likely to be much deeper
Formation testing	Testing may include drill stem tests, diagnostic fracture injection tests, or production of small volumes of water and/or gas over a period of days to weeks (gas produced must be used if commercially feasible, or flared if it is not technically or commercially feasible to use it, or vented if flaring is not technically practicable)	Testing may include drill stem tests, diagnostic fracture injection tests, or production of small volumes of water and/or gas over a period of days to weeks. Typically involves some hydraulic fracturing to test reservoir performance (produced gas must be managed as for CSG; oil and liquids are captured and stored onsite before transport to a processing facility)

Resource project phase	CSG	Shale gas and oil
Duration	Maximum duration of an ATP is 12 years	As for CSG
Scale	Maximum size of an ATP is 100 blocks; a block size is approximately 80 km^2. A single exploration project may be made up of several authorities to prospect	As for CSG
Surface activities	Well pad construction, access road construction, water supply (for drilling fluids), water disposal (drilling fluids, produced water from well testing)	Similar to CSG. Well pad construction, access road construction, water supply (for drilling fluids and hydraulic fracturing), water disposal (drilling fluids, flowback water)
Appraisal		
Drilling	Additional drilling to further assess the size of the resource. Many tens of wells. Typically vertical, although may have horizontal section (depending on local geology and local infrastructure)	Appraisal wells are likely to be drilled with a horizontal section following the target shale formation
Hydraulic fracturing	May be required on a limited number of wells	Wells will be hydraulically fractured to allow reservoir appraisal
Reservoir testing	Production of small volumes of gas over a period of months. Well may be completed and wellhead installed before production testing (gas produced must be used if commercially feasible, or flared if it is not technically or commercially feasible to use it, or vented if flaring is not technically practicable). Significant amounts of water are usually produced (several megalitres)	Production of small volumes of gas or oil over a period of months. Well may be completed and wellhead installed before production testing. Involves hydraulic fracturing to test reservoir performance (produced gas must be managed as for CSG; oil and liquids are captured and stored onsite before transport to a processing facility). Small volumes of water are produced
Surface activity	Well pad construction, access road construction, water supply (for drilling fluids), water disposal (drilling fluids, produced water from well testing), and construction of laydown yards for supplies	Similar to CSG. Well pad construction, access road construction, water supply (for drilling fluids and hydraulic fracturing), water disposal (drilling fluids, flowback water), and construction of laydown yards for supplies
Field development		
Drilling	Full-scale drilling of production wells. Hundreds to thousands of wells for a project. Typically 1 well per well pad, and 1–2 wells per km^2	Similar to CSG, except wells will be drilled with horizontal sections following target formations, with multiple horizontal wells drilled from a single pad. Surface density (number of pads) is likely to be significantly less than CSG (around 1 well pad per 4–20 km^2)
Hydraulic fracturing	Some wells hydraulically fractured to improve performance (less than 10% of wells in Queensland have been hydraulic fractured)	All wells hydraulically fractured
Surface infrastructure	Wellheads, water separation, pipelines for gathering gas and water from wells, compression stations, water treatment facilities, water storage facilities, brine storage facilities (waste from water treatment), power supply and/or generation, pipelines for delivery to market, laydown yards for supplies, administration offices, accommodation for workforce	Similar to CSG, with treatment, storage and transport facilities required for produced gas and liquids. As the volume of produced water will likely be less than for CSG, fewer water treatment and storage facilities will be needed. Treatment infrastructure to remove specific impurities such as mercury, H_2S and CO_2 from shale gas and oil may be required
Production		
Drilling	Additional wells drilled to maintain production rates as production declines from older wells, typically through infill drilling. The rate at which wells need to be replaced will depend on local geological conditions	New wells may be drilled from either existing or new pads, extending the size and production capacity of the development
Well workover and refracturing	Workover of wells for cleaning to improve performance. Frequency depends on individual well/field. Anywhere between a 2- and 10-year cycle per well	As with CSG, shale wells will require workover and refracturing to maintain well production, although frequency of workover will vary

Resource project phase	CSG	Shale gas and oil
Production of water	Queensland CSG industry is averaging 11,000 ML/well/year during production. Highest at the start of a well's production. Produced water is usually saline (200–10,000 mg/L, primarily sodium chloride, sodium bicarbonate and traces of other compounds)	Shale gas wells are unlikely to produce significant volumes of water during production. Produced water is likely to be highly saline, and may contain organic compounds, heavy metals and NORM. Some organic compounds such as BTEX and naphthalene would require specific treatment methods
Infrastructure	Wellheads, water separation, pipelines for gathering gas and water from wells, compression stations, water treatment facilities, water storage facilities, brine storage facilities (waste from water treatment), power supply and/or generation, pipelines for delivery to market, laydown yards for supplies, administration offices, accommodation for workforce	Similar to CSG, with treatment, storage and transport facilities required for produced gas and liquids. As the volume of produced water will likely be less than for CSG, fewer water treatment and storage facilities will be needed. Treatment infrastructure to remove specific impurities such as H_20, H_2S, CO_2 and mercury from shale gas and oil may be required
Rehabilitation		
Wells	All wells must be plugged and abandoned at the end of their life. This involves removing any pumps and production tubing from the well, fully cementing the well below the surface to isolate key formations and aquifers, and removal of surface infrastructure/wellhead. Requires a workover rig	As for CSG, although shale gas and oil wells do not need to be fully cemented below the surface. These wells may be cemented in sections to isolate key formations and aquifers
Water-related infrastructure	Water treatment plants and water storage facilities (raw water and treated water) decommissioned, and water and residues disposed of	As for CSG, although the amount of this type of infrastructure will be less than for CSG
Pipelines	Pipelines decommissioned – either removed or flushed with inert material and abandoned (surface facilities along pipelines would be decommissioned and removed, and the sites rehabilitated)	As for CSG
Processing/gas handling	Compression stations and dewatering stations decommissioned and removed, and the sites rehabilitated	Gas processing facilities and compression stations decommissioned and removed, and the sites rehabilitated
Other infrastructure	Administration buildings, laydown yards, power supplies, power transmission, access roads that cannot be repurposed would need to be decommissioned and removed, and the sites rehabilitated	As for CSG

ATP = authority to prospect; BTEX = benzene, toluene, ethylbenzene, xylene; CSG = coal seam gas; NORM = naturally occurring radioactive materials
Note: This information should be considered as general in nature. Local geology, variations in practices between operators, and evolving technologies mean that the observations made here will not cover all cases. The nascent stage of shale gas and oil developments in Australia also means that the observations can only be inferred from international experience.

Table 7 Key characteristics of the technologies and engineering methods used in the life cycle of coal seam gas and shale gas and oil projects

Technology	CSG	Shale gas and oil
Drilling		
Well pad size	Approximately 1 ha	Approximately 2–3 ha. Expected to be larger than CSG to accommodate larger rigs, hydraulic fracturing spreads and drilling of multiple wells from 1 pad
Well depth	250–1,200 m	1,000–4,000 m
Well horizontal (lateral) length	0–2,500 m	1,000–5,000 m
Duration of drilling activities	1–2 weeks per vertical well. Weeks to months per horizontal well	Typically months

Technology	CSG	Shale gas and oil
Rig size	Single truck mounted to several semitrailer loads. Rig power up to 500 kW; hook load up to 60,000 kg; mast height 20 m	Multiple semitrailer loads (up to 100). Rig power up to 1,500 kW; hook load up to 500,000 kg; mast height 50 m
Well trajectory	Wells typically vertical, 1 well per well pad. Directional drilling/horizontal drilling used in some areas	The North American experience suggests that drilling multiple wells from a single pad and drilling horizontal extensions is an important part of making these projects economically viable. Likely to be the case in Australia
Well design	Typically steel casing cemented in well, in accordance with *Code of practice for constructing and abandoning CSG wells and associated bores in Queensland (Queensland Department of Natural Resources and Mines, 2017a)*	Typically steel casing cemented in well, in accordance with *Code of practice for the construction and abandonment of petroleum wells and associated bores in Queensland* (Queensland Department of Natural Resources and Mines, 2016a)
Drilling fluids	Water and water-based additives, including clays, salts and organic polymers	Similar to CSG, but typically requires more complex drilling fluid design to cope with conditions at greater depths or through less stable geological layers
Water requirements	To mix drilling fluid of up to 50,000 L	To mix drilling fluid of up to 500,000 L
Hydraulic fracturing		
Frequency	Around 10% of CSG wells drilled in Queensland have required some form of hydraulic fracturing	All shale gas and oil wells will require hydraulic fracturing
Number of stages	Vertical wells may have a single hydraulically fractured stage. Horizontal wells may have multiple hydraulically fractured stages	Slickwater treatments with multiple stages in horizontal wells have been favoured in the US since around 1997. Modern large wells in the US have 20–30 hydraulic fractured stages
Volume of hydraulic fracturing fluid injected per well	Approximately 0.25 ML	In the US, 5–20 ML is typical, comprising approximately 0.5 ML per stage over 20–30 stages
Weight of sand proppant per well	10–20 t	1,000–4,000 t
Estimated volume of reservoir stimulated	0.0001 km^3	0.04–0.1 km^3
Typical fluid composition	97% water and sand. 3% additives (primarily to increase viscosity, carry proppant, prevent corrosion of the equipment and prevent algae growth)	>99% water and sand. <1% additives (primarily to reduce friction, carry proppant, prevent corrosion of the equipment and prevent algae growth)

CSG = coal seam gas; US = United States
Note: This information should be considered as general in nature. Local geology, variations in practices between operators, and evolving technologies will mean that the observations made here will not cover all cases. The nascent stage of shale gas and oil developments in Australia also means that the observations can only be inferred from international experience.

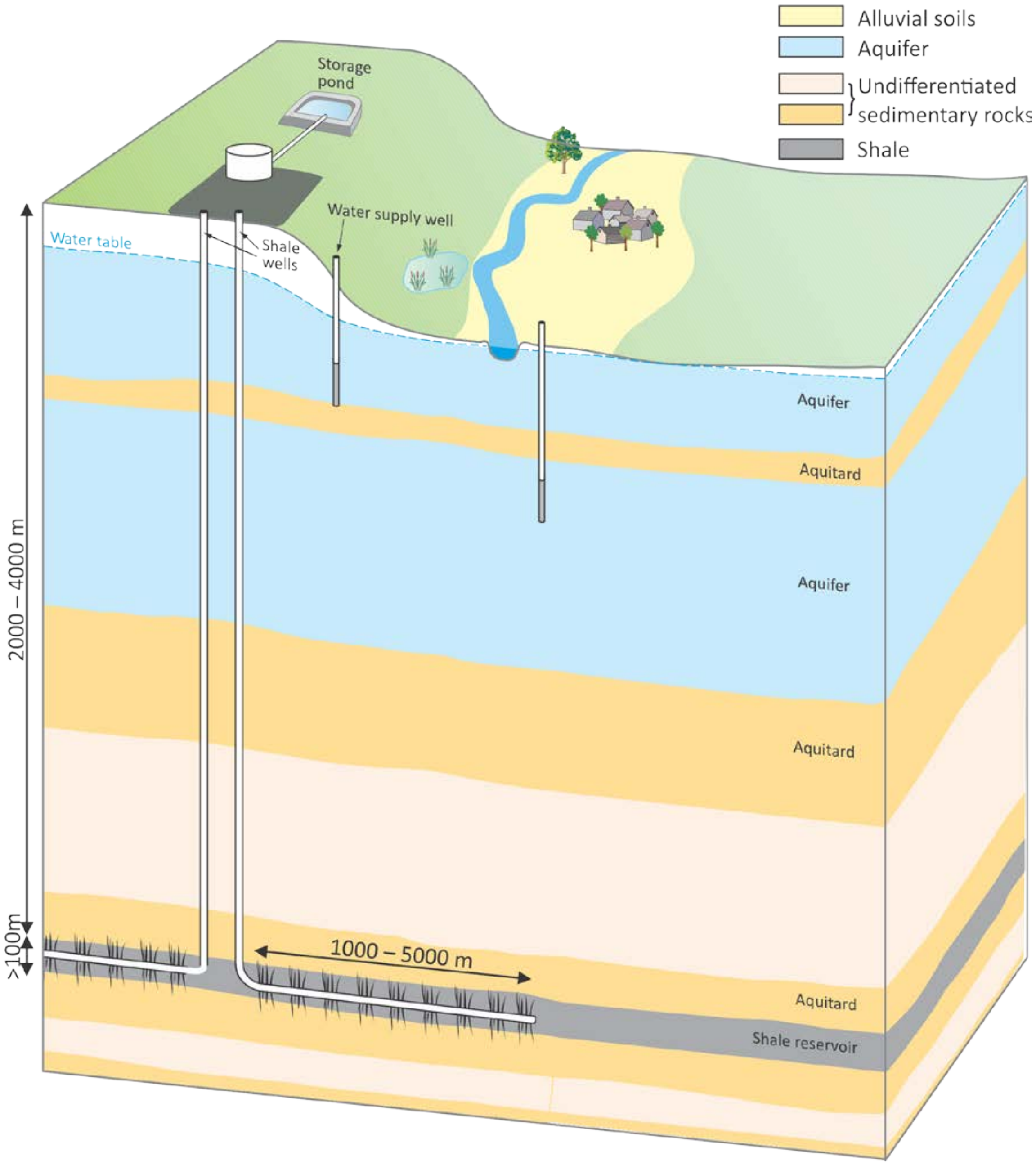
2.5 Key technologies

2.5.1 Drilling

The drilling technologies used in shale gas and oil exploration and development have evolved from those used in drilling for conventional petroleum resources. Technology advances have been critical to the establishment of shale gas and oil resources in the US. The drilling rigs used are larger and more powerful than those typically used in the CSG sector because of the depth of the resources (1,000–4,000 m), and the possibility of long, lateral components (horizontal extensions following reservoirs of interest) to the wells. Figure 11 shows the general layout of a shale gas and oil well. The drill rigs would typically use rotary mud drilling methods.

Drilling for shale gas and oil is likely to involve the drilling of multiple wells from a single well pad, in addition to horizontal or lateral extensions to the well. This increases the exposure of the well to the target formation and reduces the cost of accessing the resource. The adoption of this technology is one of the important factors in the rapid growth of shale gas and oil in the US (MIT, 2010; Cook *et al*., 2013; Council of Canadian Academies, 2014) as it has significantly reduced the cost of accessing the resource.

The Queensland Department of Natural Resources, Mines and Energy has developed a *Code of practice for the construction and abandonment of petroleum wells and associated bores in Queensland* (Queensland Department of Natural Resources and Mines, 2016a). This code sets out minimum standards for the construction and abandonment of wells drilled as part of petroleum activities, including those used in shale gas and oil activities. This code is being combined with the code of practice for CSG wells (Queensland Department of Natural Resources and Mines, 2017a), and will be mandatory as of 1 September 2018.



Note: Figure is not to scale.

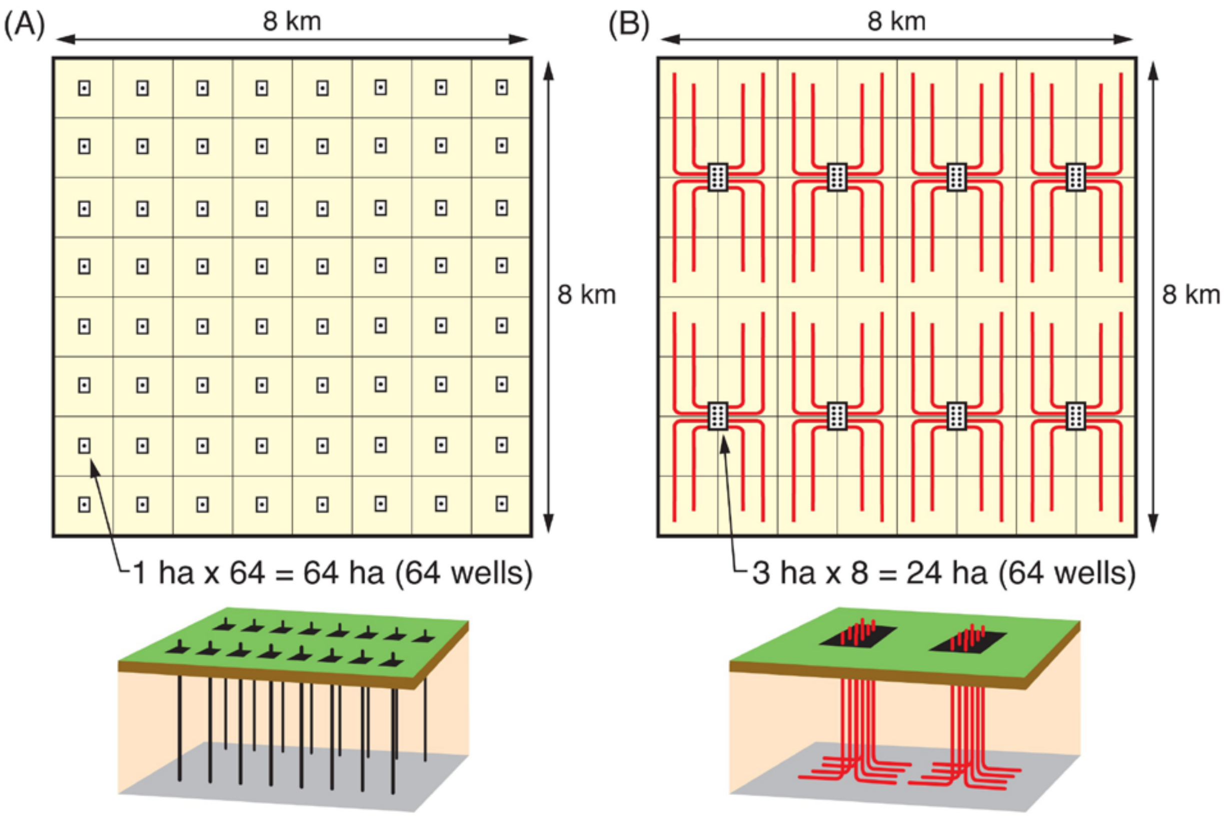
Figure 11 General layout of a shale gas or oil well

Other key drilling parameters: well pads

Shale gas and oil well pads are typically 2–3 ha. They are usually prepared using earthworks machinery to level the site. Aggregate may be laid down to allow all-weather access and operation of the drill rig. Topsoil is pushed to one side of the site and replaced after drilling. A review of US data indicated an average of 3 ha for a multi-well pad compared with 1.9 ha for a conventional oil or gas well (Broomfield, 2012).

The drilling of multiple wells from a single well pad using directional drilling methods is common in North American shale gas developments. In contrast to vertical CSG wells, this approach is likely to result in a lower density of well pads required for shale gas (as shown in Figure 12):

- 64 vertical wells drilled in an area of 8 km × 8 km, with each having a 1 ha well pad, would give a well pad density of 64 ha of well pad per 64 km^2 (or 1% of land used).
- If eight wells were drilled from a single larger well pad with horizontal legs of 2,000 m, the well pad density would be around 24 ha of well pad per 64 km^2 (or 0.375% of land used).
- Any final well pad density will depend on the length of horizontal legs of wells, the spacing between these horizontal legs, and the number of wells drilled from each pad. Optimisation of these parameters is based on the characteristics of the resources, available technologies, and economic optimisation that considers costs, production rates and ultimate recoveries from the wells.



Note: This example assumes an area of 64 km^2, 1 ha well pads for single wells and 3 ha well pads for multi-well drilling. Single wells are assumed to be vertical and spaced at 1 well per square kilometre. In the multi-well case, wells are assumed to have 2 km horizontal legs, with adjacent wells 500 m apart. Each horizontal well covers 1 km^2 of the reservoir (2 km × 500 m). The red lines show the trajectory of the wells in (B). In both examples, there are 64 wells; however, in the single well case, 64 ha of the surface has been disturbed for well pads, whereas, in the multi-well pad case, only 24 ha has been disturbed. The figure is not to scale.

Figure 12 Comparison of land use for (A) single well pad drilling and (B) multi-well pad drilling

The well pad may have one or two sumps to store water and catch drill cuttings. These sumps have a capacity of 0.5–1 ML. Drilling mud can also be held in tanks. The drilling muds are usually stored in mud tanks, recycled and filtered to separate mud from cuttings. The storage requirements for the hydraulic fracturing stage will be significantly larger, for both hydraulic fracturing fluid and flowback water.

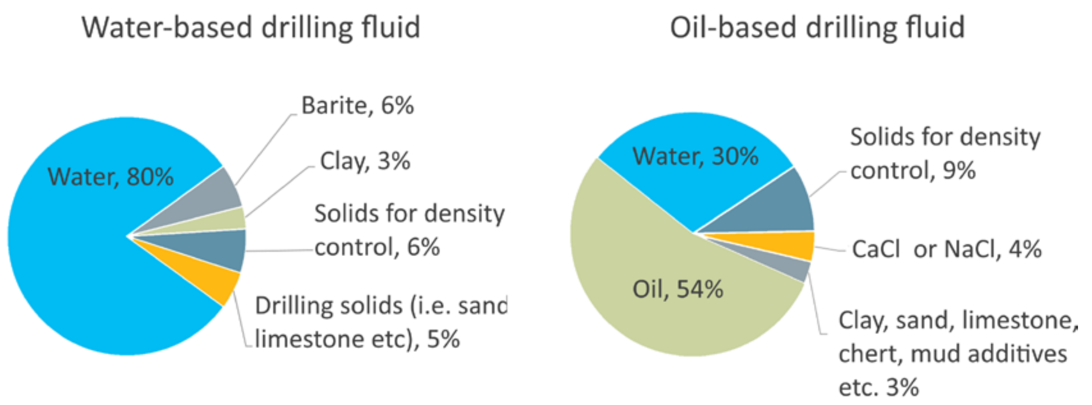
The lateral or horizontal extensions are typically 1,500–5,000 m. Their length will depend on geological conditions and operational requirements.

Well pads require access tracks. Thousands of kilometres of tracks may be required, depending on the size of the gas field, although existing road infrastructure may also be used. The tracks are generally 4–6 m wide and need to be able to handle thousands of truck movements. Drilling multiple wells from a single well pad will reduce the access track requirements.

Other key drilling parameters: drilling fluids

Drilling fluids (see Figure 13) typically comprise a water, oil or synthetic based with additives that modify the friction between the drill rods and the bore walls, increase density and viscosity of the fluid to aid in the removal of cuttings, and decrease the reactivity of the drilling fluid with the formations being drilled. These additives include:

- mineral barite or other weighting agent to increase the density of the drilling fluid to suppress high pore pressures
- clays (primarily bentonite) to increase the viscosity of the drilling fluid and to reduce losses of drilling fluid into the formations being drilled
- salts (typically potassium chloride or potassium sulfate) to limit damage to the formation being drilled and increase the density of the drilling fluid
- polymers to increase viscosity and provide lubrication.



Source: Adapted from Hossain and Al-Majed (2015)

Figure 13 Possible water-based and oil-based drilling fluid compositions

The amount of drilling fluid required for a well will be around 0.5–1 ML, although this will vary depending on the depth/length of the well and the characteristics of the formations the well intersects.

Oil-based and synthetic drilling muds are currently prohibited in Queensland under the streamlined model conditions for petroleum activities (Queensland Department of Environment and Heritage Protection, 2016a) and are not authorised under the 'Eligibility criteria and standard conditions: petroleum exploration activities' (Queensland Department of Environment and Heritage Protection, 2015b).

Other key drilling parameters: drill cuttings

Drill cuttings are waste rock removed from the hole when a well is drilled. A 3,000 m well interval with a 2,000 m lateral extension drilled using rotary mud drilling methods will produce around 150–200 m^3 of drill cuttings. The cuttings may be disposed of onsite using a mix–bury–cover method. However, if they contain potentially harmful components, they are handled as a regulated waste. Drill cuttings have traditionally been captured in drilling sumps or pits. However, pitless drilling techniques may be deployed to provide better management of the drilling fluid and cuttings.

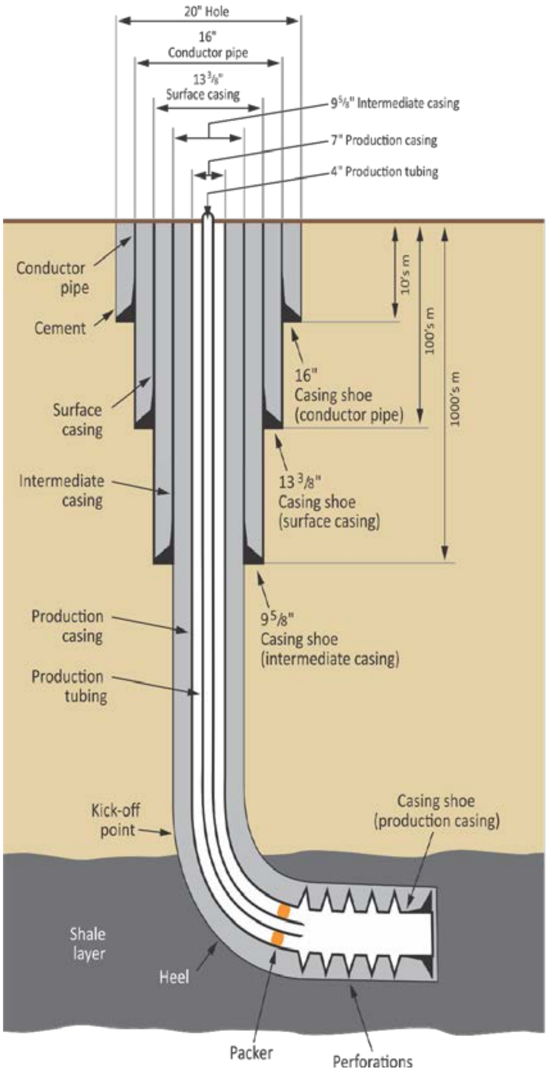
Other key drilling parameters: well casing

Several layers (strings) of steel casing are used throughout the well, and this casing is cemented in place.

The steel casing:

- isolates shallow aquifers from petroleum-bearing formations and the well
- provides well control (managing pressure 'kicks')
- prevents well collapse
- isolates shallow formations from drilling muds during drilling of deeper formations.

Multiple casing strings are used to provide multiple layers of protection between the well and the surrounding rock formations. This casing is left in the well at the completion of drilling to provide ongoing well integrity for the life of the well (see Figure 14).



Casing/hole sizes

Inches	Centimetres
20	50.8
16	40.6
13⅜	34.0
9⅝	24.4
7	17.8
4	10.2

Source: Huddlestone-Holmes *et al.*, 2017

Figure 14 General layout of casing in a shale gas well. Casing sizes are specified in imperial units. Not to scale (width is significantly exaggerated).

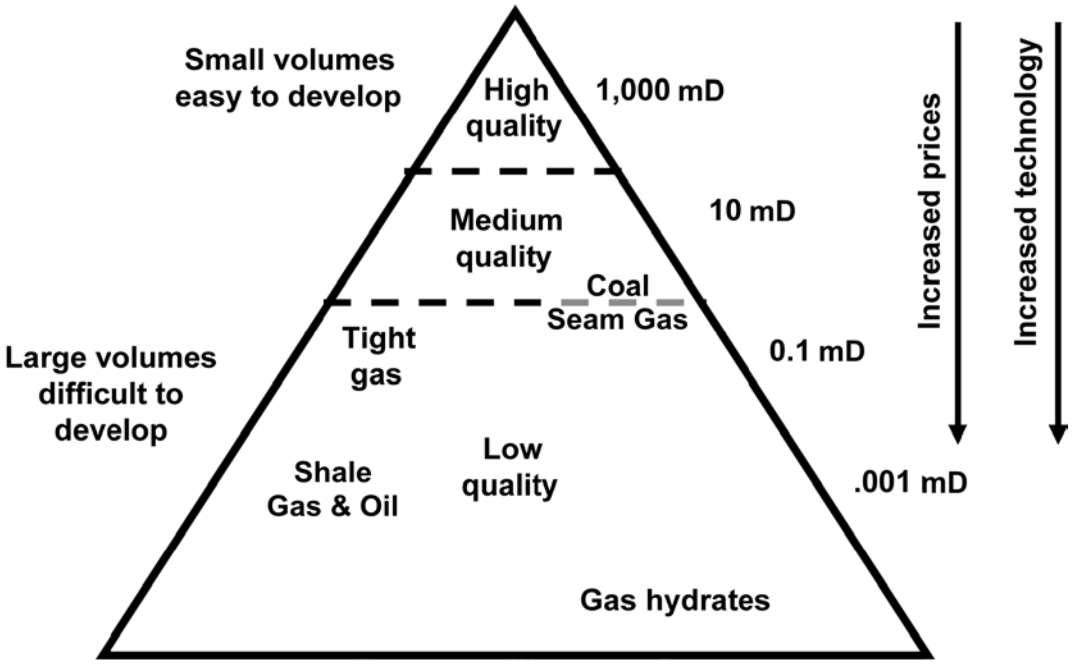
The next stage in the life cycle of a well after drilling has been completed will depend on the purpose of the well. The well may be completed as a production well, placed on standby, or plugged and abandoned. In all cases, the well pad is rehabilitated. Solid drilling residues, including drilling cuttings, are disposed of onsite or removed to a waste handling facility. Any drill sumps are backfilled, top soil is replaced, and the site is revegetated. If the well is placed into production or kept on standby, a small portion of the well pad will remain around the wellhead and any other infrastructure required. Once a well is no longer required, the remainder of the well pad is also rehabilitated. Rehabilitation of the well itself involves placing barriers in the well (usually cement plugs) to isolate hydrocarbon formations from water-bearing formations. The top few metres of the well are also filled with cement, and the casing is then cut off.

2.5.2 Hydraulic fracturing

Background

Reservoir permeability has a major influence on the production rate from gas and oil resources. Figure 14 highlights the differences in permeability between high-quality conventional reservoirs and unconventional reservoirs, such as CSG and shale gas. Shale gas and oil resources require artificial production enhancement or stimulation technologies to produce gas and/or oil at an economic rate.

Hydraulic fracturing enables economic gas and/or oil production in reservoirs that have a very low natural permeability. The process creates fractures in the reservoir though which the oil or gas can flow. The hydraulic fractures are created using fluid pressure to grow cracks that are then held open with 'proppant' (usually sand) to maintain conductivity once the fluid pressure is released. It is important to note that CSG reservoirs have a higher permeability (1–50 millidarcy [mD]) than shale gas reservoirs (0.005–0.0005 mD). Because of this difference in permeability, only a proportion of CSG wells require hydraulic fracturing, whereas all shale gas and oil wells require hydraulic fracturing. Stone (2016) reported that 420 CSG wells had been hydraulically fractured in the Surat Basin and Bowen Basin CSG fields, although the time frame to which this count applies is unclear. However, it is a small proportion of CSG wells that are drilled (more than 5,000 to the end of 2015).



Source: Masters, 1979

Figure 15 Comparison of relative reservoir abundance and permeability

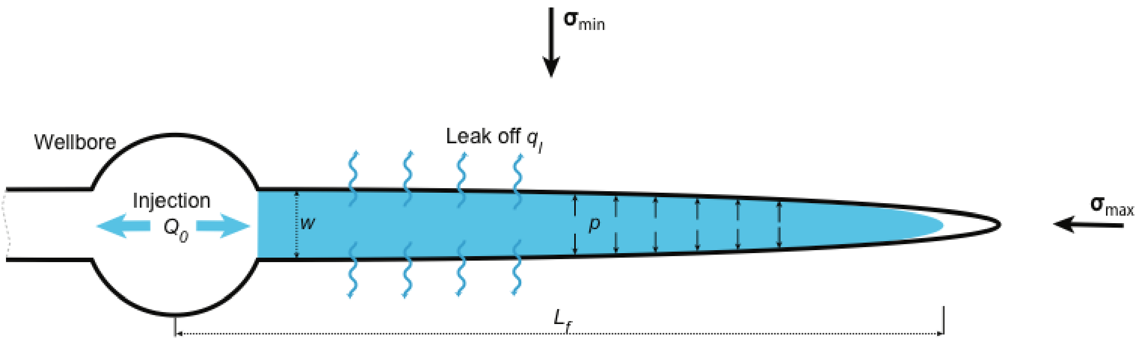
History of hydraulic fracturing

Although large-scale development of shale gas and oil resources in the US during the past 20 years has raised public awareness of hydraulic fracturing, the technology applied to oil and gas wells has been used and continually developed for almost 70 years. Over that time, hydraulic fracturing techniques and understanding have developed to increase the efficiency and effectiveness of the treatments, while reducing the risks to health, equipment and the environment. Some key milestones relevant to hydraulic fracturing are as follows:

- 1969 – The first hydraulic fracturing treatment for well stimulation in Australia was carried out in the Cooper Basin of South Australia in a tight gas reservoir (McGowen *et al*., 2007).
- 1976 – The first hydraulic fracturing treatment production test was conducted in an Australian CSG reservoir.
- 1988 – One million hydraulic fracturing treatments were completed in the US.
- 1997 – Large-scale adoption of slickwater hydraulic fracturing treatments combined with horizontal drilling for shale gas wells in the US began (Mayerhofer *et al*., 1997).
- 2016 – Five hundred wells were hydraulically fractured in Queensland during the previous five years, primarily for the appraisal and development of CSG resources (Stone, 2016).
- 2016 – Across Australia, approximately 2,100 petroleum wells have been hydraulically fractured in total. Approximately 50% (around 1,000 wells) have been hydraulically stimulated in the past decade (Stone, 2016).

How hydraulic fracturing works

Hydraulic fracturing is the use of fluid pressure to open existing fractures, and create, propagate and open new fractures in a low-permeability rock. Hydraulic fracturing fluid is injected into the well. As the fluid pressure in the well increases, the fracture toughness (strength) of the rock is overcome, and a hydraulic fracture will begin to propagate. The hydraulic fracture will propagate in a plane that is perpendicular to the minimum principal stress direction ($\sigma_{\min}$ in Figure 16).



Note: The fracture has a length of L_f and a width of w. Q_0 is the rate of hydraulic fracturing fluid injection, and p is the pressure exerted by the fluid on the walls of the fracture. σ_{min} and σ_{max} are the minimum and maximum principal stresses, respectively.
Source: Weber and Fries, 2013

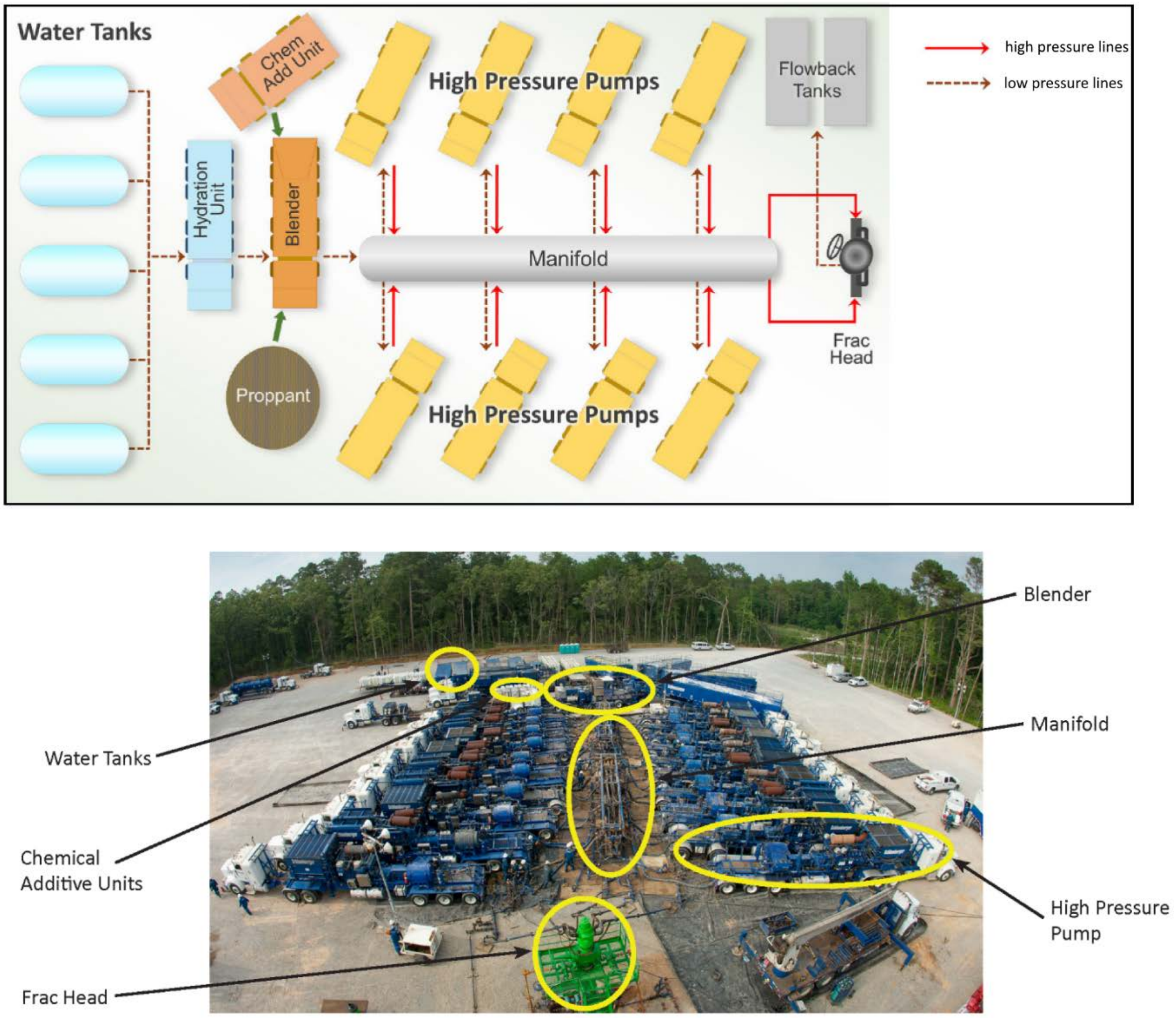
Figure 16 Propagation of a hydraulic fracture.

Hydraulic fracturing operations

A range of hydraulic fracturing techniques and approaches may be applied to shale gas and oil resources. The techniques chosen will be tailored to the needs of the particular resource being developed. The following description is based on North American shale gas and oil hydraulic fracturing operations (Council of Canadian Academies, 2014; The Ground Water Protection Council and Interstate Oil and Gas Compact Commission, 2016; US Environmental Protection Agency, 2016a), and provides an indication of the steps in a hydraulic fracturing operation. It is anticipated that hydraulic fracturing operations for Australian resources will be similar.

Hydraulic fracturing operations are usually conducted over a short period, typically less than two weeks. These operations require a range of equipment and materials to be brought to the well site, consist of multiple activities, and involve a process involving repetitive stages.

Hydraulic fracturing in shale gas and oil wells requires the mobilisation of a significant amount of plant and equipment. The most important component is the large trailer-mounted positive displacement pump units. A number of these hydraulic fracture pump units work together to inject hydraulic fracturing fluid at the required pressure and flow rate to propagate the hydraulic fracture. 'Slickwater' hydraulic fracturing fluids, as commonly used in North American shale gas and oil hydraulic fracturing operations, are typically composed of water (~90%), sand (~10%) and other chemical additives (~0.5%) that are blended and pumped from tanks and holding ponds, then through the hydraulic fracture pumps to the wellhead. Figure 16 shows a diagram of a typical hydraulic fracturing site layout (referred to as a 'hydraulic fracture spread' in industry). In addition to the hydraulic fracture pumps, other equipment used includes storage tanks for water and sand, chemical storage trucks, monitoring equipment, blending units, manifolds and high-pressure piping (Figure 16).



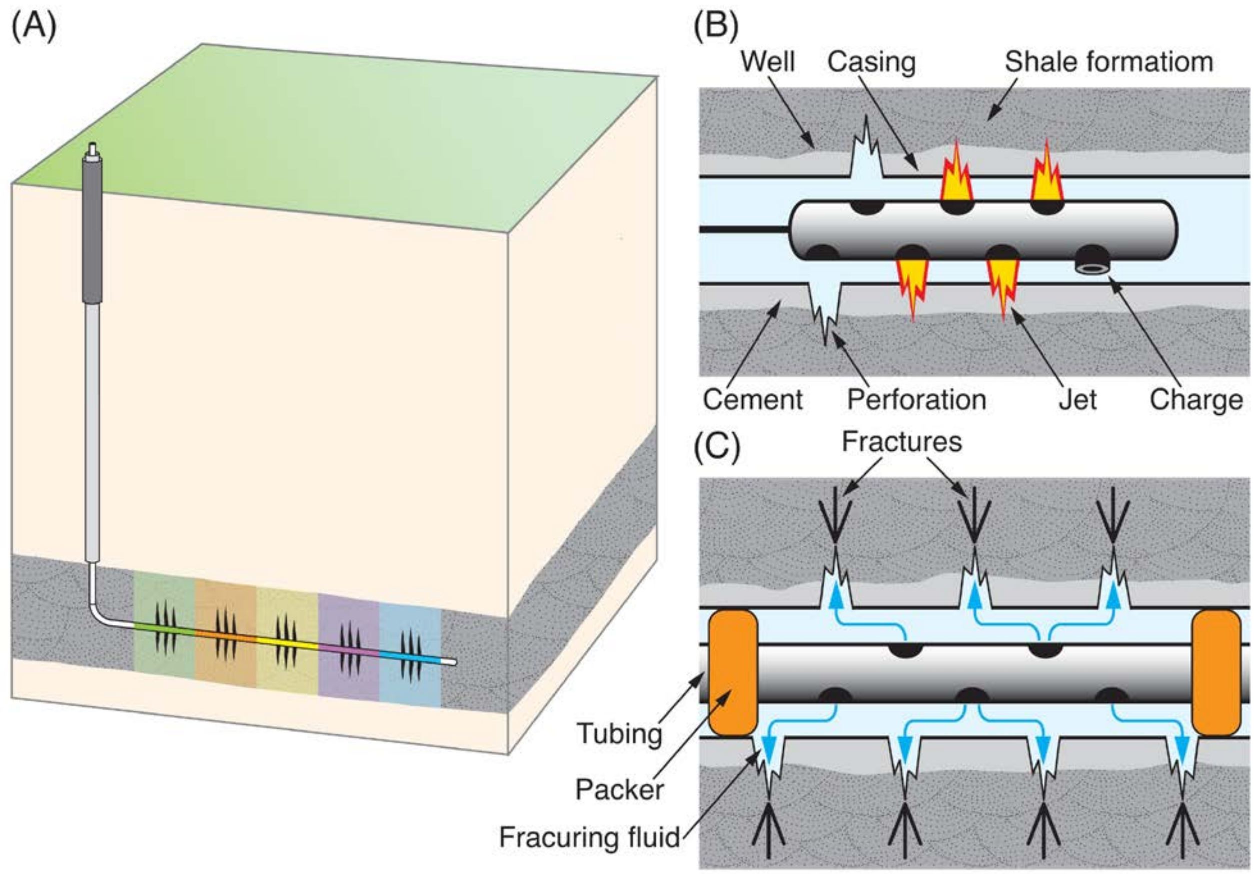
Source: US Environmental Protection Agency (2016a)

Figure 17 Schematic of a typical shale hydraulic fracturing equipment layout (top) and photograph of a hydraulic fracturing operation at a well site (bottom)

Hydraulic fracturing of a shale gas or oil well is usually conducted over a number of intervals along the production zone of the well, called ‘hydraulic fracture stages’ (Figure 17). Hydraulic fracturing of each stage treats a discrete volume of the reservoir. This staged approach allows more control of the hydraulic fracturing process. It is also generally not possible to hydraulically fracture the whole well in one step. For each hydraulic fracture stage, the steel casing in the well must be perforated to allow the hydraulic fracturing fluid to access the reservoir, and to allow gas and oil to flow into the well during production. This step is typically done using a perforation gun that uses small explosive charges to punch holes in the casing. The interval of the well is then isolated with packers, which allow the hydraulic fracturing fluid to be focused on that stage. The hydraulic fracturing fluid is then injected. This injection process may consist of a number of steps:

1. **Spearhead/acid step.** This step involves injection of diluted acid to clear debris from the well and allow hydraulic fracturing fluids unhindered access to the target interval.
2. **Pad step.** This step involves injection of hydraulic fracturing fluid without proppant to initiate the hydraulic fracturing in the target interval. In this step, additives such as friction reducers and clay stabilisers are used to facilitate fluid flow.
3. **Proppant step.** Once the hydraulic fractures have initiated and opened sufficiently widely, proppant material (usually sand) and gelling agents (guar or xanthate gum) are added. The increased viscosity of the fluid improves the transport of proppants into the created hydraulic fractures. The proppant will remain in the formation once the pressure is reduced and ‘prop’ open the fracture network, thus maintaining the enhanced permeability created by the hydraulic fracturing program.
4. **Breaker step.** Gel breakers are used to liquefy gelled hydraulic fracturing fluid to promote flowback and recovery of some of the hydraulic fracturing fluid at the surface. This step is only required if gels are used.
5. **Flowback step.** After the injection is complete, the hydraulic fracturing and formation fluids are allowed to flowback to the surface to be collected and treated.
6. **Flush step.** Fresh water is pumped down the well to flush out any excess proppant and gels.

Once the injection is complete, the process is repeated for each stage along the production zone of the well.



Note: Hydraulic fracturing is typically conducted in stages. Each coloured zone in (A) showing a different stage. For each stage, the casing must be perforated (B) to allow the hydraulic fracturing fluid to access the shale formation. Hydraulic fracturing is then conducted in each stage within a short section of the well that has been isolated, in this case using packers (C). A range of technologies are used for staged hydraulic fracturing. Figure is not to scale.

Figure 18 Hydraulic fracturing stages

Hydraulic fracturing fluids

Hydraulic fracturing fluid is the mixture of water, proppant and additive chemicals. It is pumped down the well under pressure to initiate and grow hydraulic fractures. The ideal hydraulic fracturing fluid will maximise the connected reservoir volume and long-term permeability of the created fracture network. Considerations for the design of a suitable hydraulic fracturing fluid include:

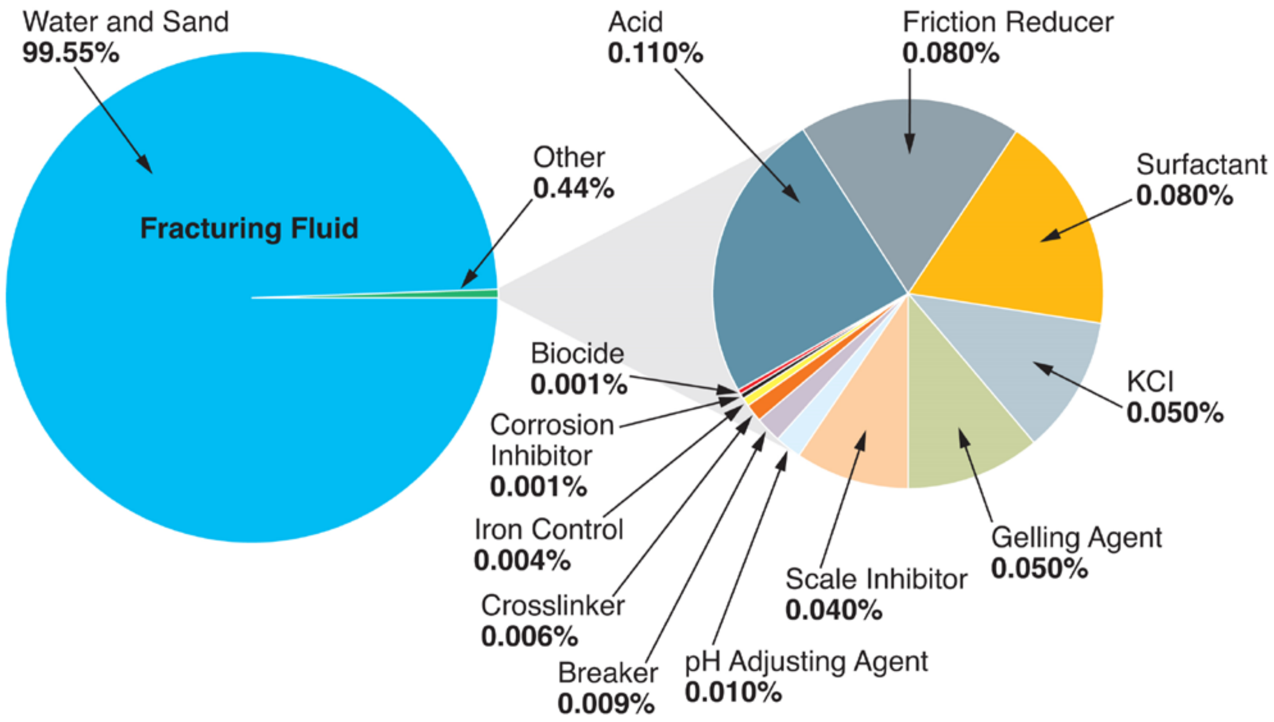
- leak-off rate into formation matrix and natural fracture network
- control of unwanted biological (algae) growth in fracture fluid
- chemical interaction with formation rock and formation fluid
- friction losses during injection and effective transport of sand (proppant)
- remaining fluid residue post-treatment
- cost
- wear on hydraulic fracturing pumping equipment
- risk of harm from exposure to chemicals.

There is no standard composition for hydraulic fracturing fluid. These fluids are usually water based, but can also be foams or emulsions made with nitrogen, carbon dioxide, or hydrocarbon- or acid-based fluids.

The most common hydraulic fracturing fluid systems used in shale gas and oil are ‘slickwater’ formulations. Slickwater is a water-based hydraulic fracturing fluid that has added friction reducers, which reduce the viscosity, allowing high pumping rates. Gelled hydraulic fracturing fluids, which are more viscous, are an alternative water-based formulation that can transport more proppant for a given volume than slickwater formulations and are used in formations with higher permeabilities. The volumes of hydraulic fracturing fluid can be significant, with modern North American shale gas and oil treatments commonly using 5–20 ML of fluid per well.

Common chemical additives

As highlighted in Figure 19, most slickwater hydraulic fracturing fluid formulations are composed of water and sand (proppant). Additives depicted on the right-hand side of Figure 19 are used to improve the performance of the fracture treatment, prevent corrosion of the equipment and suppress algal growth. In the US, a typical shale gas or shale oil slickwater hydraulic fracturing fluid contains 3–12 additives (right-hand side of Figure 19), with a composition that depends on the characteristics of the available water and the shale formation being hydraulically fractured. Table 8 provides the purpose and description of each additive as used in North America.



Source: Adapted from Arthur *et al*., 2009

Figure 19 An example of additive types used in a slickwater hydraulic fracturing fluid

Although water and proppant make up most typical hydraulic fracturing fluid formulations, the large volumes of fluid required mean that significant quantities of additives can also be needed. The Council of Canadian Academies (2014) reference material compiled in King (2012) states that a typical 20 ML slickwater hydraulic fracturing treatment of a North American shale well could use 1,500 t of proppant, 900 kg of disinfectant, 1 t of friction reducer, 300 L of corrosion inhibitor and 100,000 L of acid. There is a move in the industry to adopt food-grade additives to reduce the potential for environmental impacts (Cook *et al*., 2013).

Table 8 Purpose and description of hydraulic fracturing fluid additives

Additive type	Purpose and description	Common additives
Water	Creates hydraulic fractures and transports proppant	Fresh water (less than 500 parts per million total dissolved solids)
Proppant	Maintains fracture openings to allow the flow of gas. Stays in formation embedded in fractures (used to 'prop' fractures open)	Sand Clay or alumina ceramics
Friction reducer	Reduces friction pressure, which decreases the necessary pump energy and subsequent air emissions	Non-acid form of polyacrylamide Petroleum distillate Mineral oil
Acid	Helps dissolve minerals and initiate cracks in the formation	Hydrochloric acid Muriatic acid Carbonic acid
Disinfectant (biocide)	Inhibits the growth of bacteria that can destroy gelled fracture fluids or produce methane-contaminating gases	Glutaraldehyde 2,2-dibromo-3-nitrilopropionamide
Surfactant	Modifies surface and interfacial tension, and breaks or prevents emulsions, aiding fluid recovery	Naphthalene 2-Butoxyethanol Methanol/isopropanol 1,2,4-Trimethylbenzene Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy Ethoxylated alcohol
Crosslinker	Cross-linking gels enable higher viscosities to be achieved	Borate salts Potassium hydroxide
Scale inhibitor	Prevents mineral deposits that can plug the formation	Polymer phosphate esters Phosphonates Ethylene glycol Ammonium chloride
Corrosion inhibitor	Prevents pipes and connectors rusting	N,N-dimethylformamide Methanol Ammonium bisulfate
Breaker or gel breaker	Introduced at the end of a fracturing treatment to reduce viscosity, release proppants into the fractures and increase the recovery of the fracturing fluid	Peroxydisulfates Sodium chloride
Clay stabiliser	Prevents the swelling of expendable clay minerals, which can block fractures	Potassium chloride Salts (e.g. tetramethyl ammonium chloride)
Iron control	Prevents the precipitation of iron oxides	Citric acid
Gelling agent	Increases the viscosity of the fracturing fluid to carry more proppant into fractures	Guar gum Cellulose polymers Petroleum distillates
pH adjusting agent	Adjusts and controls the pH to enhance the effectiveness of other additives	Sodium or potassium carbonate Acetic acid

Sources: Adapted from Cook *et al.*, 2013; Council of Canadian Academies, 2014; The Ground Water Protection Council and Interstate Oil and Gas Compact Commission, 2016

Slickwater hydraulic fracturing fluid formulations usually start with fresh or low-salinity water, because this makes it easier to control the chemistry. The industry is actively pursuing hydraulic fracturing fluid technologies that allow lower-quality (salty, or saline) water or recycled hydraulic fracturing fluids to be used (Cook *et al*., 2013; Council of Canadian Academies, 2014). For example, about 60–80% of flowback water in the Marcellus shale in the US was reused (Broomfield, 2012; Veil, 2015). Technical and economic limitations influence the degree of feasibility of recycling. In some shale gas and oil resources, the amount or rate of flowback is too low for reuse to be viable.

The use of saline water in hydraulic fracturing is still in the early stages of development. However, more compatible additives are being developed, such as friction reducer chemicals that work in water with salinity levels up to 70,000 ppm (twice the salinity of sea water). Where saline water is used, increased amounts of additives, including viscosifying agents, may be required (Council of Canadian Academies, 2014). This may lead to higher costs, although these may be offset by the costs of obtaining fresher water.

Another development that may reduce the use of water is the use of other fluids such as methane, propane, nitrogen or carbon dioxide (Council of Canadian Academies, 2014). These methods would not require any water. An advantage of water-free approaches is that they do not cause formation damage (e.g. swelling of formation shales), which can happen with water-based fluids. These alternative techniques are at the early stages of development.

Hydraulic fracturing in Queensland

Multi-stage hydraulic fracturing is a rapidly evolving technology, and techniques vary between regions, resource plays and service companies. Horizontal wells combined with water-based slickwater hydraulic fracturing fluids will likely be deployed in shale gas and oil resources in Queensland, because of the success in US reservoirs. However, it is too early to determine the exact approaches that will be most appropriate, successful and productive for the Queensland industry. Shale gas and oil hydraulic fracturing methods are highly likely to vary from those used in Queensland's CSG sector because of the differences in the characteristics of the resources.

Queensland regulations restrict the use of additives that may contain polycyclic aromatic hydrocarbons and BTEX chemicals (benzene, toluene, ethylbenzene and xylene). The allowable levels of BTEX chemicals in hydraulic fracturing fluids are so low that these chemicals cannot be added. A risk assessment must be conducted for hydraulic fracturing operations as part of an EA application, and the impacts of the chemicals used is one of the aspects that must be addressed.

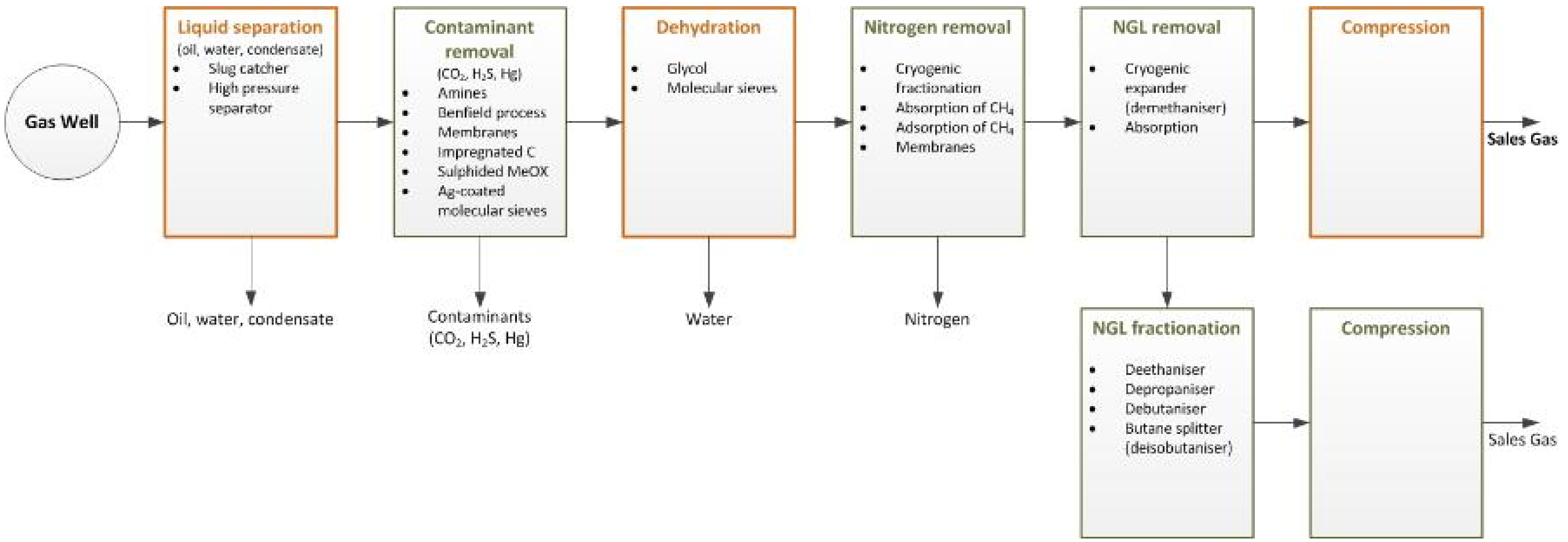
2.5.3 Gas and oil processing

The processing requirements for a particular gas resource are determined by the gas composition. The high degree of variability of raw gas compositions between resources means that there is a high degree of variability in the requirements for gas processing in the field and the detailed design of gas processing plants. Field processing may be required (dehydration, removal of condensable gasses) to get the gas to a composition that is suitable for pipeline transmission to a central processing plant or to market. Field compression will also be required to send gas through pipelines.

Most gas processing plants follow a basic process, which is presented in Figure 20. All gas processing plants have some kind of liquid separator to capture the liquids (water and hydrocarbons) during production that condense as the gas temperature and pressure drop when the gas is brought to the surface. Further dehydration will invariably be required to lower the water content to a point suitable for transport in pipelines, and compression will be required to drive the gas through transmission pipelines. Other steps in the process will only be used if the gas composition and the specification for the processed natural gas require it. These steps include removal of acid gases such as carbon dioxide and hydrogen sulphide in gas sweetening units; nitrogen removal, usually via cryogenic processes; and separation of natural gas liquids (ethane, propane and butane, where present) for sale as liquefied petroleum gas or as petrochemical feedstock (ethane is used for ethylene production).

Oil receives limited field processing before it is transported to refineries. Condensates will be captured from gas at the well head, and there will be gas separation from any oil produced. Produced water will also be separated from condensate or oil. Condensate and/or oil may be collected in tanks at the well pad before being transported to refineries by road or rail, or sent piped to

The CSG industry in Queensland has processing facilities within the gas fields that dehydrate and compress the gas for either domestic consumption or delivery to LNG processing facilities. Further processing is undertaken at the LNG plants to remove contaminants (such as carbon dioxide, hydrogen sulphide and higher-order hydrocarbons) and to dehydrate the gas. In general, the processing requirements for CSG are considerably less than would be expected for most shale gas or oil resources.



Note: The processes in orange (liquid separation at or near the wellhead, dehydration and compression) are common to all processing plants to some degree. The other processes would only be required based on the raw gas composition

Figure 20 Generalised flow diagram for a gas processing plant

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Part II Potential impacts of shale gas and oil developments

3 Approach to reviewing impacts

Part II of this report summarises the potential impacts of shale gas and oil developments, and associated activities in Queensland across their life cycle, based on a review of the available literature. The impacts have been evaluated in two ways:

- materiality – this is a qualitative assessment based on the intensity, scale and duration of the impact, and how often the impact may occur
- requirement for regulatory focus – this considers whether shale gas and oil development activities, their scale and their impact are new in the Queensland context. If the activities and impacts are new, or occur at an increased scale compared with previous experience, they may require a high level of attention during the assessment and approval process for shale gas and oil projects.

This chapter describes the approaches taken in this review to the risk assessment process.

3.1 Risk assessment overview

Risk assessments are an integral component of risk management and are applied in a range of contexts. Examples are assessment of environmental risks of large developments, assessment of the business and technical risks in the installation of a new enterprise software system, and assessment of health and safety risks of a particular task on a construction project. Risk assessments are used to identify, characterise and evaluate risks so that appropriate controls can be implemented. They are routinely used in the oil and gas, and mining industries.

Risk assessment – key terminology

Risk is defined as the effect of uncertainty on objectives. Risk is often expressed in terms of the likelihood of an event and its consequences. An effect is a deviation from the expected. Objectives include financial, health and safety, and environmental goals.

Risk assessment is 'the overall process of risk identification, risk analysis and risk evaluation'. (International Organization for Standardization, 2018). Risk assessment is a core component of risk management that informs *risk treatment*, which is the development of options to address risk.

Environmental objectives are generally framed in terms of preventing or minimising harm to environmental assets.

An *asset* is an entity having *value* to the community that may be managed, and/or used to maintain and/or produce further value. The values of an asset may be ecological, sociocultural or economic.

A *hazard* is an event, or chain of events, that might result in an *impact*.

Impact modes are the manner in which a hazardous chain of events (initiated by an impact cause) could result in an effect.

An *impact* is a change resulting from prior events, at any stage in a chain of events. An impact might be equivalent to an effect (e.g. change in the quality or quantity of surface water or groundwater), or might be a change resulting from these effects (e.g. ecological changes that result from hydrological changes). *Consequences* are a synonym for impacts.

Likelihood is the chance that something might happen.

Materiality is the significance or relevance of an impact.

Risk identification is the identification of risks that might occur as part of an organisation's activities, or that may affect those activities.

Risk analysis is the characterisation of all aspects of identified risks, including causes, impacts and likelihood.

Risk evaluation is the process of comparing the results of risk analysis with risk criteria to support decisions on further action to manage risks.

A *qualitative* risk assessment is based on general observations or knowledge of the risks. Estimates are made for the risk components (consequence and likelihood) based on the judgment of those conducting the assessment.

A *quantitative* risk assessment is based on a numerical description of the consequences and likelihood of risks, often with probabilities, and a mathematical evaluation of the resulting risk. The focus is on factual and measurable data, and models for the relationship between impact modes, assets and risk.

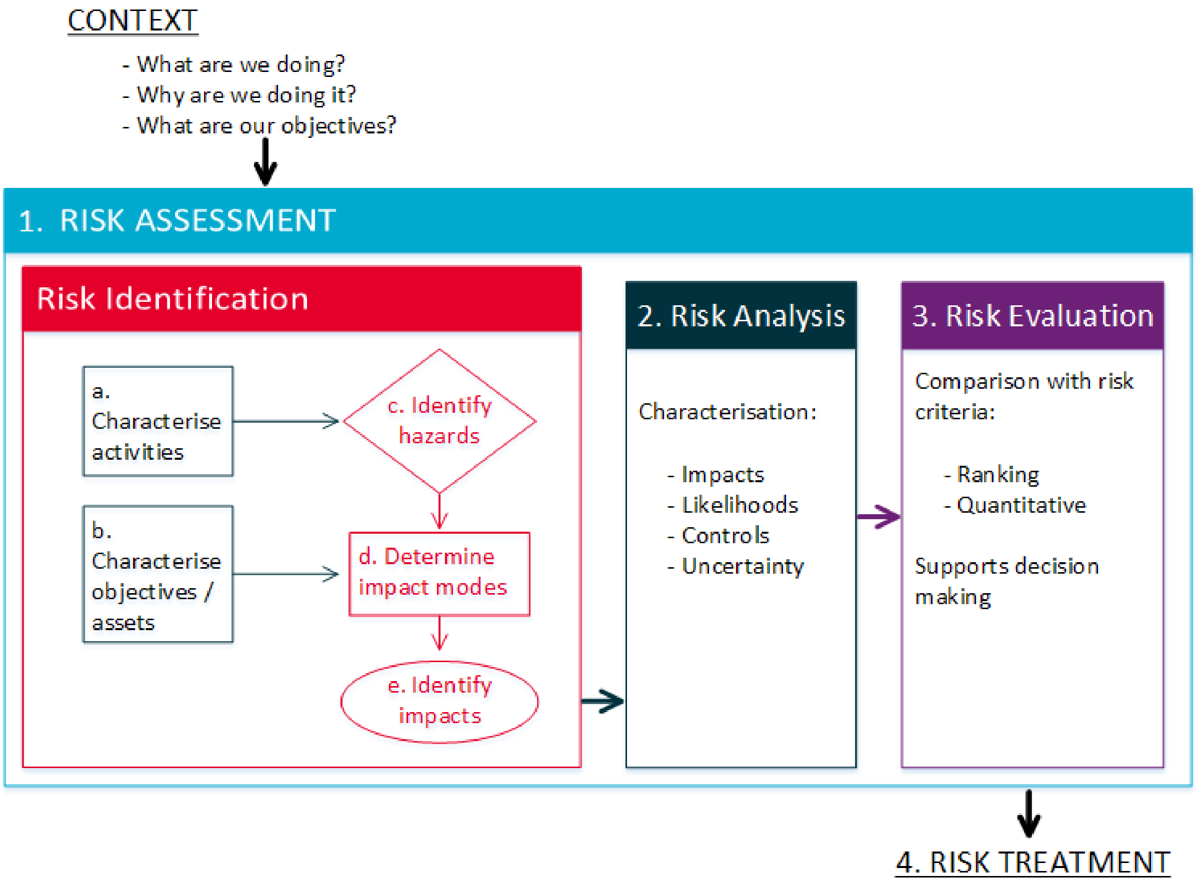


Figure 21 Generalised risk assessment process as part of an overall risk management approach

Figure 21 shows the general risk assessment process as part of an overall approach to risk management. The context is an important input because it determines the activities and objectives for the risk assessment. A risk assessment typically has the following stages:

1. Risk identification. The risk identification stage has the following steps
    a. The activities are characterised.
    b. Potential hazards that result from the activities are identified.

c. The assets or objectives that may be affected by the hazards are characterised.

d. The impact modes (the ways in which the hazards may cause an effect on the assets or objectives) are determined.

e. The impacts that result from the impact modes are identified.

2. Risk analysis. In the risk analysis stage, the risks or impacts are characterised in detail, including the level of risk (consequence and likelihood), the uncertainty in the knowledge of the risk, and the controls that are in place to manage the risks.
3. Risk evaluation. In the risk evaluation stage, the risks are evaluated, usually against established risk criteria, to determine where additional action may be necessary to manage them. Embedded risk treatment options are also considered. The risks are ranked so that the most important risks to manage can be identified.
4. Risk treatment. The results of risk evaluation inform the development of risk treatment options.

A variety of approaches can be applied to each component of the risk assessment process. These depend on the context of the risk assessment and whether the activities are new or have a long history of operation.

The level of constraint that can be placed on the context for a risk assessment will determine the level of detail for the assessment, and whether a qualitative or quantitative risk assessment can be conducted. For example, a risk assessment for the drilling of a specific shale gas well development in a known location can be conducted in detail and with a high degree of certainty. A quantitative risk assessment is also likely to be possible because of the amount of information available. In contrast, a risk assessment for a possible future shale gas industry for an entire state or region will have a higher degree of uncertainty, and a qualitative risk assessment may be more appropriate.

3.2 Approach used in this review – materiality of impacts

This review has covered the initial hazard identification and risk analysis components of the risk assessment process shown in Figure 21 with a high-level evaluation of impacts. The context of the review is an assessment of the potential impacts of shale gas and oil activities in Queensland. The focus has been on the activities that are expected to be typical of most shale gas and oil operations, using the international literature to gain some insight into the possible expansion of the limited development of these resources in Queensland. Because the review covers shale gas and oil resources across Queensland, the assets that may be impacted by these activities have been generalised into broad categories: water, land, human health, flora and fauna, air, and other industries. Impacts related to waste and induced seismicity have been assessed separately. This is a similar approach to the high-level assessments of shale gas and oil activities undertaken in other jurisdictions (The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; US Environmental Protection Agency, 2016a; Pepper *et al*., 2018).

3.2.1 Impact Modes and Effects Analysis

In this report, the assessment of impacts is based on the approach used for bioregional assessments (Barrett *et al*., 2013). Impacts have been identified and analysed using a process similar to the Impact Modes and Effects Analysis (IMEA) described in submethodology M11 of the bioregional assessments (Ford *et al*., 2016). IMEA is based on Failure Modes and Effects Analysis (FMEA), a 'bottom-up' hazard analysis tool routinely applied to industrial processes. FMEA identifies and analyses hazards by examining the possible failure modes of an industrial system's components. In the application of FMEA to the assessment of resource development, the focus is not only on failures but also on the hazards that can arise as part of normal petroleum or mining activities. In this case, the use of the term 'failure' is inappropriate and potentially misleading. IMEA focuses on impacts, rather than failures.

The IMEA process starts with a description of the activities and the hazards. Impact modes and impacts on the various asset categories associated with these activities are identified. The impacts are then analysed in terms of their intensity, scale, frequency and duration. The sensitivity, value and quality of the environment that is being impacted is also considered. The criteria used are presented in Section 3.7.

The impacts are then evaluated to determine their materiality (i.e. their significance or importance). This analysis also considers whether the same or similar impact modes exist in other activities in Queensland, whether the impact mode is unique to shale gas and oil development, and the prevalence of the impact mode in shale gas and oil development. The impacts have been categorised qualitatively based on the available literature and informed by experts in their domains into three levels of materiality:

- **High** – despite existing controls, the impact has potential to result in significant harm to an environmental, ecological or economic value.
- **Moderate** – despite existing controls, the impact has potential to result in a moderate impact on an environmental, ecological or economic value.
- **Low** – with existing controls, the impact has potential to cause only low or no impact on an environmental, ecological or economic value.

For example, the impacts of urban development in a previously undeveloped location could be considered to be highly material because these impacts are intense, can cover several square kilometres, are irreversible, and happen every time this activity occurs. Immaterial impacts might be dust or noise caused by the movement of vehicles during drilling operations, because these impacts have low intensity, have a limited geographic extent, are episodic (not continuous), are reversible and may not occur for all drilling operations.

The definition of materiality of impacts used here is similar to the principles employed in defining environmental harm in Queensland's EP Act. Although there are similarities, this review is general in nature, and therefore the definitions in the Act (e.g. around environmental values, materiality of impacts) have not been directly applied.

3.2.2 Limitations of this assessment

The development of shale gas and oil is only just beginning in Queensland, and therefore there is limited information in the literature specific to the potential impacts of the development of the state's shale gas and oil resources. This review is a high-level qualitative assessment based on the available literature on the impacts of shale gas and oil resources in other locations, primarily North America. The results provide an overview of the potential impacts of shale gas and oil development in general. They do not necessarily describe the impacts of any particular operation (because the exact nature of the activities is not known), or the impacts on any specific assets or values that need to be protected or enhanced (which may be area specific). This will inevitably leave blind spots or overemphasise some impacts. A more complete risk assessment requires greater understanding of the activities and assets being assessed, so that risks can be properly identified.

It is important to emphasise that the focus is on the identification of potential impacts and high-level analysis of their materiality, not absolute risk estimation.

3.2.3 Relationship to other risk assessments

The Geological and Bioregional Assessments (GBAs) are an example of this regional-scale assessment, with studies on the impacts of shale and tight gas development on the environment in the Cooper Basin, Isa Superbasin (both with significant Queensland components) and Beetaloo Basin bioregions (Department of the Environment and Energy, 2018). The GBA program was announced in May 2017, and is managed by the Australian Government Department of Environment and Energy. Geoscience Australia and CSIRO are conducting the assessments, supported by the Bureau of Meteorology. The GBAs follow on from the bioregional assessments that examined the impacts of coal mining and CSG on water-dependent assets (Barrett *et al*., 2013). The GBAs will develop scenarios for shale and tight gas development, and characterise the water-dependent assets within each bioregion. This will allow a quantitative risk assessment to be conducted at basin scale. The GBA work being conducted in the Cooper Basin and Isa Superbasin will provide a starting point for more detailed environmental risk assessments in these regions.

Should a proponent plan to develop shale gas and oil resources, they would have certainty about the proposed activities, and the assets and values that could be impacted. As part of the approval process in Queensland, as outlined in Section 1.3, the proponent is required to conduct an EIS, which includes a detailed risk assessment and detailed environmental assessments. There may also be a requirement to conduct a risk assessment and detailed environmental assessments under the EPBC Act if the proposed activities have, or are likely to have, a significant impact on a matter of national environmental significance, such as threatened or migratory species.

3.2.4 Direct, indirect and cumulative impacts

Impacts may affect the natural environment, community or economy. Impacts can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes (Barrett *et al*., 2013).

An example of a *direct* impact is a reduction in the water level of an aquifer as a result of extraction of water from that aquifer.

Indirect impacts on the environment occur as a result of a pathway of cause and effect. An example of an indirect impact is a reduction in the water level in a wetland as a result of the reduction in the water level of an aquifer in the previous example.

Cumulative impacts occur as the result of multiple direct or indirect impacts on the same system. These kinds of impacts can occur in parallel or in sequence, and can be distributed in time and space. An example of cumulative impacts is the combined effects of the reduction in water level in the wetland in the previous example with a degradation in water quality in the wetland due to contamination caused by a surface spill.

This study has focused on direct impacts and has not included ‘positive’ impacts (such as increased economic activity). Indirect and cumulative impacts have not been considered in detail. These impacts are highly complex, and describing all of the potential contributing factors and their interactions under a range of possible scenarios would require a much larger study, and indeed a greater analysis of region- and site-specific factors. Furthermore, the study has not considered how future events such as extreme rainfall or long-term climate change may compound or mitigate impacts identified.

3.2.5 Management of impacts

This review does not aim to explore ways in which the identified impacts are managed or mitigated by industry; this is beyond the terms of reference of the review and would require a more detailed study. The impacts have, however, been assessed in the context of current practices and regulatory requirements. This review does identify and discuss existing Queensland regulatory instruments that apply to managing and mitigating the identified impacts, and this has been considered in determining the materiality of the impacts. An assessment of the effectiveness of the implementation of these regulatory instruments is beyond the scope of the review.

3.3 Comparison with CSG developments

A comparison of the potential impacts of shale gas and oil developments with the existing impacts of CSG developments has been made throughout this review. This similar industry is well established in Queensland, and provides useful context for assessing the potential impacts of shale gas and oil developments and their regulation. Consideration has also been given to whether impacts are decreased, similar, or increased compared with those of CSG developments, and this has been factored into the evaluation of the requirements for regulatory focus (see Section 3.4). The comparison has been ranked as follows:

- **Increased** – impacts that are distinctly more material than for CSG because of greater intensity, scale, duration or frequency.
- **Similar** – impacts with an intensity, scale, duration or frequency that is broadly the same as for CSG.
- **Decreased** – impacts that are distinctly less material than for CSG because of lower intensity, scale, duration or frequency.

3.4 Requirements for regulatory focus

The requirement for regulatory focus is based on how unique and/or prevalent the impact is to shale gas and oil operations, and whether or not it is already part of other activities regularly conducted in Queensland. The Queensland regulatory regime for the management of the environmental impacts of resource activities is risk based. This approach relies on the identification of risks during the assessment and approval stage of resource activities so that appropriate controls can be put in place (see Section 1.3 for further discussion). Consideration of the impacts identified in this review is important in a risk- or objective-based regulatory regime because it will help to identify potential impacts that may require additional attention when assessing and approving shale gas and oil projects. The requirement for regulatory focus has been ranked as follows:

- **High** – the initiating activity is unique to, or highly prevalent in, shale gas and oil operations, or is not already part of other activities regularly conducted and regulated in Queensland.
- **Moderate –** the initiating activity in shale gas and oil operations is already conducted to a similar extent and regulated in Queensland in other resource activities.
- **Low** – the initiating activity exists in other routine activities already taking place across several sectors and regulated in Queensland.

This assessment of the requirement for regulatory focus may be useful when considering the aspects of the approvals process for shale gas and oil projects, including:

- development of the terms of reference for an EIS
- adaptation of the streamlined model conditions for petroleum activities
- development of EA conditions for site-specific applications for certain shale gas and oil activities
- updates to policies and guidelines (such as the *Code of practice for the construction and abandonment of petroleum wells and associated bores in Queensland*).

3.5 Review workshop

The assessment of impacts of shale gas and oil for the various aspects are described in Chapters 4–11 and impact tables. A workshop was undertaken to review these aspects, attended by the authors of the report and other technical experts, including environmental consultants to the industry, Queensland Government representatives (from relevant agencies) and a member of the GBA team. The workshop focused on the materiality of the assessed impacts outlined in the report. This was conducted in a qualitative manner, relying on the experience and expertise of the authors of this report and others present at the workshop. To ensure that the materiality of the impacts was evaluated in an internally consistent manner, the workshop assessed the information presented in the impact tables in Chapters 4–11. The workshop also evaluated the requirement for regulatory focus for each impact, using the criteria outlined in section 3.4 and current environmental authority conditions (especially streamlined model conditions for oil and gas activities in Queensland).

3.6 Structure of following chapters

In addition to impacts on environmental values and human health, this review also broadly considers the potential impacts of shale gas and oil development on other Queensland industries, including agriculture and tourism. It focuses on impacts of a physical nature, such as potential impacts on the utility and availability of land for agriculture, and the implications for co-existence with other industries. Socioeconomic impacts have also been reviewed at a high level. The results of the impact analysis are presented in Chapters 4–11. Each chapter covers a particular category of environmental values (or assets), or particular hazards, in the case of waste management and induced seismicity:

- Chapter 4: surface water and groundwater resources, including water use, and potential impacts on water quality, riverine ecosystems and aquifers
- Chapter 5: land
- Chapter 6: waste management
- Chapter 7: human health, including noise and amenity
- Chapter 8: native vegetation and fauna
- Chapter 9: air quality, including greenhouse gas emissions (including fugitive emissions)
- Chapter 10: induced seismicity
- Chapter 11: other industries, including impacts on agriculture and tourism.

Each chapter has the following structure:

1. Chapter summary of the key impacts identified, including an overview table of the nature and scale of impacts.
2. Relevant context for the impact area.
3. Discussion of impacts.
4. Comparison with CSG development.
5. Summary of relevant regulations that apply in Queensland.

A table listing the potential impacts is provided in each chapter. These tables contain a summary of the mode of impact, the environmental value (asset) impacted, the intensity of the impacts, their scale or magnitude, their duration, their timing or frequency, a comparison with CSG development, and the materiality of the impact. Table 9 provides a more detailed description of the information contained in these tables.

Table 9 Example of a summary impact table

Impact	Impact mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
	Brief description of the activity or event that leads to the impact	Brief description of the impacts caused by the initiating event. A single initiating event may result in multiple impacts	Brief description of the environmental value that is impacted	Degree to which the environmental value is affected by the impact	Geographical scale of the impact	Time over which the impact occurs	How often the impact is likely to occur. This assessment is based on an activity that is well regulated and operated	Regulations that are in place to mitigate the impact	Level of uncertainty in this assessment of the impacts	High-level rating of the relevance or importance of the impact	Simple indication of whether the materiality of the impact is less than, similar to, or greater than that impact in the CSG sector	
Examples												
WA.2	Taking of surface water for hydraulic fracturing process See related impacts VF.8 and OT.2	Removal of water from surface water systems; changes to water quality	Surface water that may be used for other purposes, or that supports flora and fauna	Medium. Volumes taken for an individual well are unlikely to be significant; cumulative impacts are likely to be greater	Local to regional	Weeks to months	High, but only in resource areas with access to surface water	EIS identifies impacts to water resources. Water Act applies to extraction of water from the environment. RPI Act also protects water resources. EA model conditions include requirements to protect water values. EP Act has a general requirement to avoid harm. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems	Low.	Moderate (intensity). Dependent on water resources used	Increased. Water use for hydraulic fracturing in shale resources is likely to be more than for CSG	High. Already regulated for other sectors. High prevalence of hydraulic fracturing for shale resources will mean high levels of water use
VF.3	Emission of compounds and particulate matter during operation of wells	Increase in air pollution – decreased air quality decreases survival, growth and reproduction of terrestrial plants	Native vegetation	Low	Limited to local	Months to years	High	EIS identifies flora and fauna at risk. EA model conditions include requirements to protect flora and fauna. EP (Air) Policy EP Act has a general requirement to avoid harm	Low	Low	Similar. Scale and intensity of development are similar; different bioregions may result in differences	Low. Impacts of air quality are regulated in multiple sectors

CSG = coal seam gas; EA = environmental authority; EIS = environmental impact statement; EP Act = *Environmental Protection Act 1994* (Qld); EPBC Act = *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth); RPI Act = *Regional Planning Interests Act 2014* (Qld); Water Act = *Water Act 2007*

3.7 Impact materiality criteria

For each potential impact, a qualitative analysis, based on the literature reviewed for this report, is provided for the following impact criteria:

- intensity
- scale
- duration
- frequency
- uncertainty.

This information is then used to determine the materiality of the impact, and a comparison with CSG development.

Potentially positive impacts have been noted in some sections of this report, but identifying and describing the positive impacts has not been the major focus.

3.7.1 Intensity

The intensity of the impact is determined by the nature of the effect of the impact on the asset that is impacted:

- **High** – the impact causes a highly concentrated, severe and/or irreversible effect on the environmental value that is impacted.
- **Medium** – the impact causes a moderate effect on the environmental value, which may be remediated.
- **Low** – the impact causes a dispersed, temporary and/or reversible effect on the environmental value, which may be minimal or can be easily remediated.

3.7.2 Scale

The scale of the impact is the size of the area that the impact affects:

- **Limited** – the impact occurs in the immediate vicinity of the activity, tens of square metres to hectare scale.
- **Local** – the impact occurs at the paddock scale, up to several tens of square kilometres.
- **Regional** – the impact occurs at the well field scale, hundreds of square kilometres.

3.7.3 Duration

Duration refers to the duration of the impact mode and is described qualitatively in terms of days, weeks, months, years or decades.

3.7.4 Frequency

The frequency of the impact is determined by whether the activities that result in impacts are an integral part of the shale gas and oil development life cycle (e.g. drilling a well), only happen in certain circumstances, or occur as infrequent or inadvertent events:

- **High** – the impact occurs every time, or almost every time, an activity is conducted.
- **Low** – the impact is rare or only occurs in certain circumstances that do not occur often.
- **Inadvertent** – the impact only occurs as a result of an inadvertent event, including accidents (e.g. a leak of drilling fluid from a holding tank), noncompliance, natural hazards or system failures.

3.7.5 Uncertainty

The uncertainty is evaluated based on how well the impact is covered in the literature, whether there are conflicting points of view, and how well the literature relates to the Queensland context:

- **Low** – well covered in literature; literature or issue relevant to Queensland context; highly plausible in the development of shale gas and oil resources in Queensland.
- **Medium** – moderate coverage in literature; relevance to Queensland not clear in literature; probable in the development of shale gas and oil resources in Queensland.
- **High** – poorly covered in literature or conflicting points of view; relevance to Queensland questionable; plausibility in the development of shale gas and oil resources in Queensland highly dependent on the technologies and development practices eventually deployed.

3.7.6 Materiality

The overall materiality is evaluated based on all the preceding criteria. This is similar to assessing risk based on consequence and likelihood. The intensity, scale and duration are aspects of consequence. Frequency is one input into determining likelihood, in that it describes how often the activity takes place and whether the impact occurs as a routine part of operations or as a result of inadvertent events. The other aspect of likelihood – the probability that the impact mode will occur and result in an impact – has not been evaluated. This assessment of the materiality of impacts also considers the controls, primarily through regulation, currently in place. This is a high-level analysis of the materiality of impacts, not an absolute risk estimation:

- **High** – despite existing controls, the impact has potential to result in significant harm to an environmental, ecological or economic value.
- **Moderate** – despite existing controls, the impact has potential to result in a moderate impact on an environmental, ecological or economic value.
- **Low** – with existing controls, the impact has potential to cause only low or no impact on an environmental, ecological or economic value.

4 Surface water and groundwater resources

4.1 Summary of potential water impacts

The potential impacts of shale gas and oil development on water resources are of primary concern (The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014; US Environmental Protection Agency, 2016a; Pepper *et al*., 2018). The main potential impacts identified are:

- the quantity of fresh water consumed by shale gas operations
- surface spills causing potential unregulated release of contaminants to surface water and groundwater resources
- appropriate storage, treatment and discharge of flowback and produced water (wastewater), and associated contaminants
- wastewater treatment accidents that may result in releases of improperly treated process water
- flow of contaminants from deep petroleum production formations or reinjection wells through well casings (well integrity issues) to overlying drinking water aquifers by leakage of natural gas or saline waters
- long-term implications of abandoned shale gas wells and the potential for migration of contaminants and naturally occurring elements from deep rocks to ground and surface waters (well integrity issues).

Potential impacts on water systems are well covered in the international literature. However, there is limited direct experience with shale resources in Australia. The literature covers the possible mechanisms for impacts and provides a few examples of observed impacts. Overall, existing peer-reviewed literature lacks studies with substantive comparisons of water quality before and after natural gas development. This is largely due to a lack of baseline data on water quality before the advent of unconventional natural gas development**,** and the lack of long-term systematic studies that investigate links between hydraulic fracturing activities and potential impacts. There is limited direct evidence of impacts on water quality.

There are similarities between shale gas and oil projects and CSG projects related to the impacts caused by surface spills of chemicals and produced water. Shale gas and oil operations will consume more water, primarily for hydraulic fracturing during the development stages of a project, than a CSG project. Conversely, although shale gas and oil will have flowback water to manage, these projects will not produce anywhere near the volumes of produced water that are typically seen in the CSG sector.

Potential water impacts are regulated through a number of regulatory instruments. The rights to the use of associated water are regulated under the P&G Act, and impacts on other users are regulated under the Water Act. Shale gas and oil projects will require an underground water impact report to evaluate and manage potential impacts on other water users. Potential contamination of water resources is regulated under the EP Act through conditions on a project's EA. There are restrictions on additives, including allowable levels of BTEX chemicals in hydraulic fracturing fluids that are so low that additives containing BTEX cannot be used. Flowback and produced water are considered as waste and regulated under the Waste Act and the EP Act through conditions on a project's EA. It is noted that under the end of waste framework (under the Waste Act), which replaced the beneficial use approval framework, a waste can be valued as a resource if it meets specified criteria; this has been used for some drilling wastes in certain situations for CSG projects (e.g. produced water that is being irrigated onto crops).

Potential well integrity issues are regulated through well design requirements under the P&G Act, and any potential contamination of surface water or groundwater is regulated under the EP Act through conditions on a project's EA. Plugging and abandonment of wells are regulated under the P&G Act, and rehabilitation requirements are regulated under the EP Act through conditions on a project's EA.

Potential impacts will be dependent on the surface water and groundwater systems that the shale gas and oil project is operating in. The uncertainty in assessing the potential water-related impacts of shale gas and oil developments in Queensland relates to the nature of the surface water and groundwater resources in the prospective shale gas and oil areas in Queensland. Many of these prospective areas are in basins that form part of, or underlie, the GAB. The GAB is an important water resource for much of western Queensland. Management of potential impacts will rely on understanding the GAB and its interactions with the basins that underlie it. Baseline studies of the GAB and its water resources will be important to better understand and monitor future impacts of resource development in the region.

The activities carried out for shale gas and oil developments involve rapidly evolving technologies and are very much dependent on the resource geology. As a result, there is uncertainty about the exact techniques that will be employed should this sector develop in Queensland. The techniques employed will have a bearing on water-related impacts because they will determine the volumes and quality of water used, and the type of chemicals used.

Table 10 Summary of impacts on surface water and groundwater resources of shale oil and gas development

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Impacts related to water extraction and disposal												
WA.1	Taking of groundwater for hydraulic fracturing process. See related impacts VF.9 and OT.2	Drawdown of groundwater levels, changes to water quality.	Groundwater that may be used for other purposes, or that supports groundwater dependent ecosystems.	Medium. Volumes taken for an individual well unlikely to cause large drawdowns, cumulative impacts likely to be greater.	Local to regional.	Weeks to decades.	High. Water for hydraulic fracturing will be required for all wells at start of project and when new wells required (and potentially other times through the well life to optimise production). Groundwater likely source for inland shale resources (e.g. Georgina Basin, Cooper Basin).	Water Act applies to extraction of water from the environment. Make good obligations under Chapter 3 of the Water Act EA model conditions – requirements to protect water values. Environmental Protection (Water) Policy EP Act general requirement to avoid harm. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems.	Low.	Moderate (intensity). Dependant on water resources used.	Increased. Water use for hydraulic fracturing in shale resources likely to be more than for CSG.	High. Already regulated for other multiple sectors, high prevalence of hydraulic fracturing for shale resources will mean high levels of water use.
WA.2	Taking of surface water for hydraulic fracturing process. See related impacts VF.8 and OT.2	Removal of water from surface water systems, changes to water quality.	Surface water that may be used for other purposes, or that supports flora and fauna.	Medium. Volumes taken for an individual well unlikely to be significant, cumulative impacts likely to be greater.	Local to regional.	Weeks to months.	High. But only in resource areas with access to surface water (e.g. Maryborough Basin).	Water Act applies to extraction of water from the environment. RPI Act also protects water resources. EA model conditions – requirements to protect water values. Environmental Protection (Water) Policy EP Act general requirement to avoid harm. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems.	Low.	Moderate (intensity). Dependant on water resources used.	Increased. Water use for hydraulic fracturing in shale resources likely to be more than for CSG.	High. Already regulated for other sectors, high prevalence of hydraulic fracturing for shale resources will mean high levels of water use.
WA.3	Wastewater disposal via subsurface injection (water may or may not be treated). Note: treatment and reuse and pond evaporation are also options.	Changes to groundwater levels or quality.	Groundwater that may be used for other purposes, or that supports groundwater dependent ecosystems.	Medium. Volumes for an individual well unlikely to cause significant changes, cumulative impacts greater.	Local.	Years to decades.	Low to High. Water disposal will be required for all wells in some form. Will depend on options available at specific location.	EA – site-specific assessment required. EA model conditions – requirements to protect water values, EP Act general requirement to avoid harm. Waste Act – general beneficial use / end of waste approvals for associated water. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems.	High. The amount of wastewater, the treatment and disposal options for Queensland highly uncertain and very dependent on the site location.	Moderate (uncertainty, frequency).	Decreased. Shale resources will produce less water than CSG wells.	Moderate. Already regulated for other petroleum activities, significant volumes of water prevalent for shale resources.
WA.4	Wastewater disposal via surface discharge (treated water).	Changes to surface water levels or quality.	Surface water that may be used for other purposes, or that supports flora and fauna.	Medium. Volumes for an individual well unlikely to cause significant changes, cumulative impacts greater.	Local.	Months to years.	Low to High. Water disposal will be required for all wells in some form. Will depend on options available at specific location.	EA – site-specific assessment required. EA model conditions – requirements to protect water values. EP Act general requirement to avoid harm. Waste Act – general beneficial use / end of waste approvals for associated water. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems. RPI Act – protects certain rivers.	High. The amount of wastewater, the treatment and disposal options for Queensland highly uncertain and very dependent on the site location.	Moderate (uncertainty, frequency).	Decreased. Shale resources will produce less water than CSG wells.	Moderate. Already regulated for other petroleum activities, significant volumes of water prevalent for shale resources.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Impacts related to contamination of water resources												
WA.5	Incidental spills and leaks at surface of drilling and hydraulic fracturing chemicals or liquid hydrocarbons during transport, storage and mixing and use. See related impacts H.3 and VF.6	Water quality impacts. Contamination of water, from the potential release of contaminants present in drilling and hydraulic fracturing fluids.	Surface water (e.g. streams, wetlands) and shallow groundwater that may be used for other purposes, and habitat for aquatic species.	High (depending on toxicity of chemicals). Chemical concentrations are undiluted.	Limited to local	Days to weeks.	Inadvertent.	TO Act (road transport). EA model conditions – storage of chemicals. EA model conditions –to protect water, land and biodiversity values, and monitoring and reporting of spills and leaks. Environmental Protection (Water) Policy WHS Act for safe storage and handling of chemicals. EP Act general requirement to avoid harm.	Low.	Moderate (intensity).	Increased. Frequency of hydraulic fracturing in shale formations likely to be more than for CSG.	Low, regulation of transport and handling of hazardous chemicals across multiple sectors.
WA.6	Leaks from storage ponds or tanks containing drilling or hydraulic fracturing fluids.	As for WA.3.	As for WA.3.	Low. Chemical concentrations are diluted.	Limited to local.	Days to weeks.	Inadvertent to low.	EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions for dams. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Low.	Low (intensity and frequency).	Increased. Frequency of hydraulic fracturing in shale formations likely to be more than for CSG.	Moderate, already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
WA.7	Leaks from storage ponds containing flowback water.	As for WA.3.	As for WA.3.	Medium. Flowback water contains hydraulic fracturing additives and formation water.	Limited to local	Days to weeks.	Inadvertent to low.	EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions for dams. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Low.	Moderate (intensity and frequency).	Increased. Frequency of hydraulic fracturing in shale formations likely to be more than for CSG.	Moderate. Already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
WA.8	Leaks from storage ponds containing produced water.	As for WA.3.	As for WA.3.	Medium. Formation water, may have high salinity, residual hydrocarbons.	Limited (small volumes of produced water).	Days to weeks.	Inadvertent to low.	EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions for dams. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Low.	Low (intensity and frequency).	Decreased. Shale resources will produce less water than CSG wells.	Moderate. Already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
WA.9	Leaks from water pipelines. Water pipelines not likely to be widely used in shale resource development.	As for WA.3.	As for WA.3.	Low to medium. Depends on water being piped – raw groundwater or flowback/produced water.	Limited (scale of the leak).	Weeks to months.	Inadvertent.	EA model conditions – requirements to protect water resource, including releases from pipelines. EA standard conditions for pipelines. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Medium.	Low (intensity and frequency).	Decreased. Other than raw water needs, shale resources will produce less water, and transport less water by pipelines, than CSG wells	Low. Unlikely to be a significant aspect of shale resource development. EA standard conditions for pipelines.
WA.10	Dust control (suppression using water).	As for WA.3.	As for WA.3.	Low. Chemical concentrations in dust are dilute.	Local.	Months to years.	High. Integral part of the shale development. Dust suppression in immediate vicinity of operations only.	EA model conditions – waste management. EP Act general requirement to avoid harm. Waste Act – general beneficial use / end of waste approvals for associated water.	Medium.	Low (intensity)	Decreased. Fewer access tracks likely due to pad drilling.	Low, already regulated for other petroleum activities.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
WA.11	Overflow or breaches from storage ponds. Related to flooding or structural failure. See related impacts WA.6, WA.7 and WA.8.	As for WA.3.	As for WA.3.	Low to medium. Chemical concentrations of drilling and hydraulic fracturing fluid are diluted. Flowback or produced water may be more hazardous.	Limited.	Days to Weeks.	Inadvertent.	EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions for dams. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Medium.	Low to moderate (depends on fluid in storage pond).	Decreased. Shale resources will produce less water than CSG wells, but the volume of drilling fluids will be increased per well.	Moderate. Already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
WA.12	Storage ponds remain onsite with residual contamination accumulated at its base, followed by leakage through the liner.	As for WA.3.	As for WA.3.	Medium. Chemicals may be concentrated (through evaporation).	Limited. Remaining volumes will be small.	Days to weeks.	Inadvertent.	EA model conditions – waste management. EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions – rehabilitation requirements. EA model conditions for dams. Environmental Protection (Water) Policy EP Act general requirement to avoid harm.	Medium.	Low to moderate (depends on fluid in storage pond).	Decreased. Shale resources will produce less water than CSG wells, but the volume of drilling fluids will be increased per well.	Moderate. Already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
Impacts related to down-hole												
WA.13	Loss of drilling fluid during drilling operations.	Contamination of shallow groundwater systems.	Groundwater that may be used for other purposes, or that supports groundwater dependent ecosystems	Low. Concentrations in the subsurface likely to be diluted, drilling muds used for shallow parts of the well use benign chemistry.	Limited.	Days to weeks.	Inadvertent. Losses during normal drilling operations will be limited.	EA model conditions – requirements to protect water values. EA model conditions – synthetic muds prohibited. Code of practice for construction and abandonment of petroleum wells under P&G Regulation. EP Act general requirement to avoid harm.	Low.	Low (intensity, frequency).	Similar. Drilling through shallow aquifers is similar in both cases.	Low. Regulation of drilling in petroleum, minerals and groundwater sectors.
WA.14	Loss of hydraulic fracturing fluid in the target formation.	Contamination of deep groundwater systems.	Deep groundwater that may be used for other purposes.	Low. Concentrations in the subsurface likely to be diluted, low environmental value of target formations.	Regional, aquifer.	Decades	High. Hydraulic fracturing will be required for all wells.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm.	Low.	Low (intensity)	Increased. Frequency of hydraulic fracturing in shale resources likely to be more than for CSG.	Moderate. Already regulated for petroleum activities, high prevalence of hydraulic fracturing for shale resources.
WA.15	Leaks from production casing into overlying aquifer during hydraulic fracturing.	Contamination of groundwater and soil from organic and inorganic compounds present in drilling fluids, hydraulic fracturing fluids.	Groundwater that may be used for other purposes, and supply surface water that supports flora and fauna.	Low. Concentrations in the subsurface likely to be diluted.	Limited (small volumes).	Years	Inadvertent.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	High.	Low (intensity, frequency)	Increased. Frequency of hydraulic fracturing in shale resources likely to be more than for CSG.	Moderate. Already regulated for petroleum activities, high prevalence of hydraulic fracturing for shale resources.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
WA.16	Leaks via offset wells into overlying aquifer during or after hydraulic fracturing.	Contamination of groundwater systems.	Groundwater that may be used for other purposes.	Low. Concentrations in the subsurface likely to be diluted.	Limited (small volumes).	Years.	Inadvertent. Requires offset wells with poor integrity. Not likely to be a significant issue in Queensland.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	High.	Low (intensity, frequency)	Increased. Frequency of hydraulic fracturing in shale resources likely to be more than for CSG.	Moderate. Already regulated for petroleum activities, high prevalence of hydraulic fracturing for shale resources.
WA.17	Improperly completed or plugged offset wells providing pathways for contamination of groundwater during hydraulic fracturing (well integrity issue).	Contamination of groundwater systems.	Groundwater that may be used for other purposes.	Low. Concentrations in the subsurface likely to be diluted.	Limited (small volumes).	Years.	Inadvertent. Requires offset wells with poor integrity or that have been improperly abandoned. Not likely to be a significant issue in Queensland.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	High.	Low (intensity, frequency).	Similar. Long-term well integrity similar, shorter migration distance for CSG wells.	Moderate. Already regulated for petroleum activities. High prevalence of hydraulic fracturing for shale resources.
WA.18	Vertical migration of hydraulic fracturing fluid and formation fluid along faults and fractures.	Contamination of ground water systems.	Groundwater that may be used for other purposes.	Low. Concentrations in the subsurface likely to be diluted, even more so during migration.	Local, aquifer.	Years.	Inadvertent. Requires presence of a suitably conductive structure and a pressure gradient to drive vertical flow.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm.	Medium.	Low (intensity, frequency).	Greater. Frequency of hydraulic fracturing in shale resources likely to be significantly greater than for CSG.	Moderate. Already regulated for petroleum activities, high prevalence of hydraulic fracturing for shale resources.
See L.1, L.2, L.3 and L.4.	Impacts related to erosion are covered in the Land chapter (Section 5)											

4.2 Context

4.2.1 Queensland's water resources

As outlined in Section 1.2.2, Queensland has two broad water resource regimes:

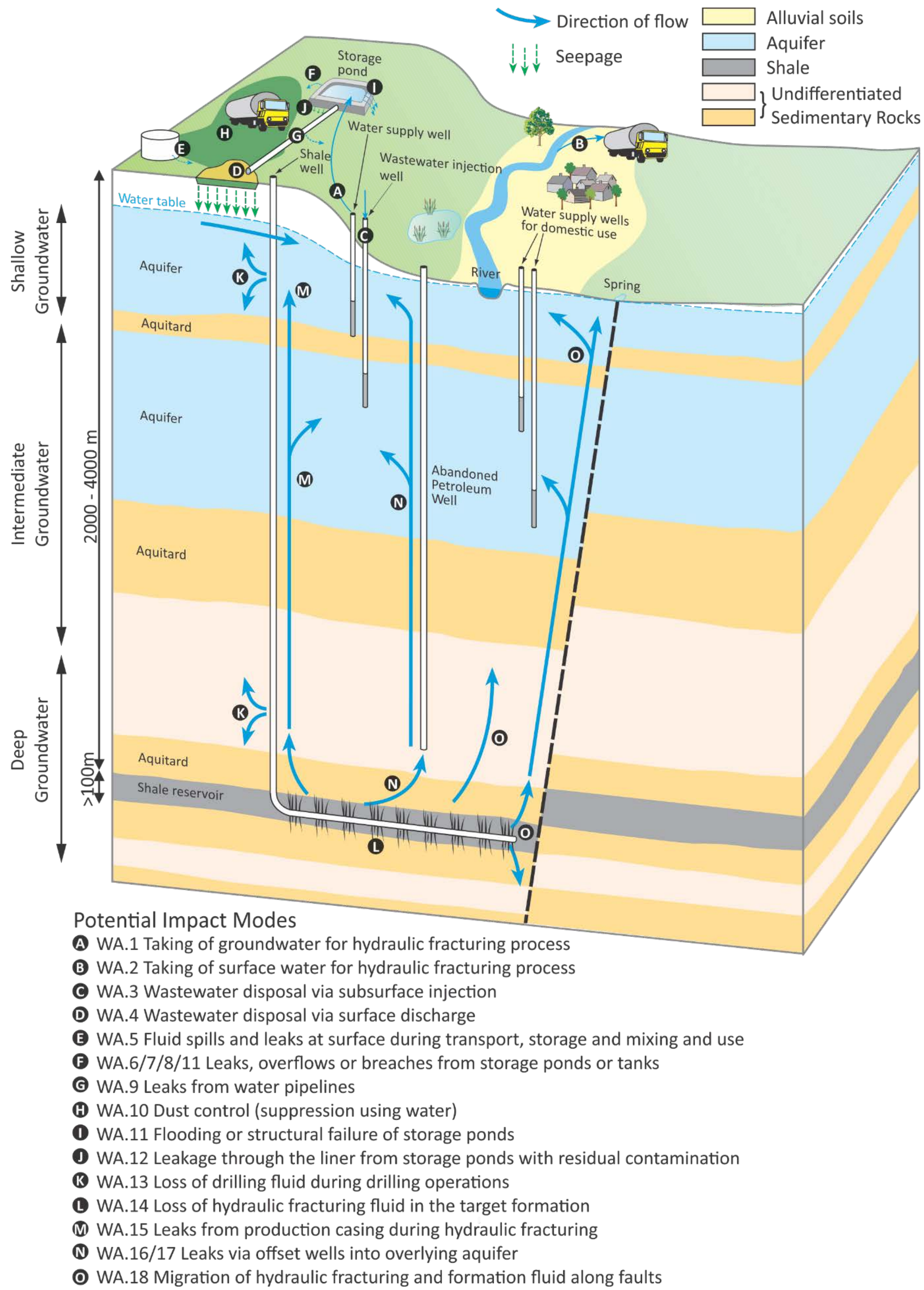
- areas that receive high rainfall, typically near the coast, which have access to surface water resources most of the year
- areas in inland semi-arid to arid environments, where surface water is scarce, which have access to the significant groundwater resources contained in the GAB.

The impacts of the shale gas and oil life cycle on water resources will be influenced by these environments. Figure 22 shows typical surface water systems, such as rivers, creeks and wetlands, as well as potential pathways for impacts in these systems.

The Council of Canadian Academies (2014) considers groundwater in terms of three zones: deep, intermediate and shallow (Figure 22). Shallow groundwater is typically water that is potable, or potable after minimal treatment, and usually interacts with surface water. The maximum depth of this zone will depend on local hydrogeology, but is usually in the order of hundreds of metres. The deeper groundwater zones can be divided into deep and intermediate zones. The transition between these zones is not formally defined. The Council of Canadian Academies (2014) refers to the deep zone as groundwater in and around the shale formations being targeted. This groundwater is typically highly saline, having been in contact with the formation for millions of years. The intermediate zone is the water between the shallow groundwater and deep groundwater, which may be of varying quality, but tends to be brackish to saline. These zones are arbitrary, and their applicability will depend on the nature of the groundwater systems in the area of interest.

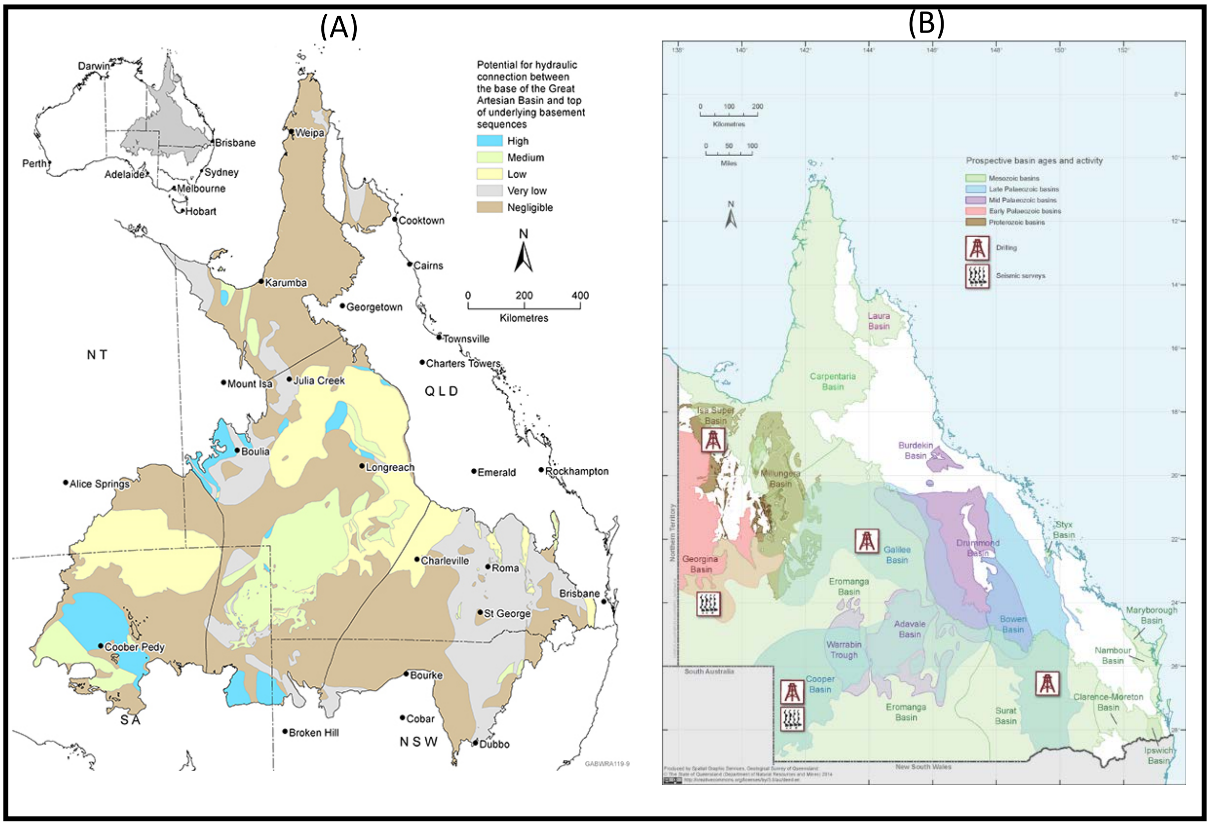
As outlined in Section 1.2.2, the GAB is a very important water resource in Queensland, supplying water for drinking water for many rural communities, as well as water for agriculture. The aquifers of the GAB overlie many of the prospective shale gas basins in Queensland (Figure 23). GAB aquifers include those at shallow depths (including watertable aquifers such as the Winton–Mackunda Formation), as well as at great depth (Figure 24). The Eromanga Basin, which has been developed for conventional oil production as well as being prospective for shale gas and oil, is a major component of the GAB. Many of the sedimentary basins prospective for shale gas and oil (see Table 2) directly underlie the GAB, including the Bowen, Cooper, Galilee, Warburton and Adavale basins, and the Warrabin Trough (Figure 25).

The descriptions of water quality in the shallow, intermediate and deep zones used by the Council of Canadian Academies (2014) are not transferrable to the GAB. In the Eromanga Basin, for example, prospective shale horizons may be interbedded with productive aquifers that are suitable for agriculture or drinking water. Prospective shale resources in other basins overlain by the GAB may be immediately below productive aquifers, and there may be hydraulic connections between these basins and the GAB. The general context of three zones from an engineering perspective – a shallow near-surface zone that may be impacted by surface activities, a deep zone that may be impacted by hydraulic fracturing and other activities within the shale gas and oil resource, and an intermediate zone between the shallow and deep zones – does provide a useful context for discussing potential impacts and is used throughout this section.



Note: See text for further discussion. Figure is not to scale.

Figure 22 Sketch of potential impact modes in relation to surface water and groundwater systems which may be encountered in shale gas or oil environments.



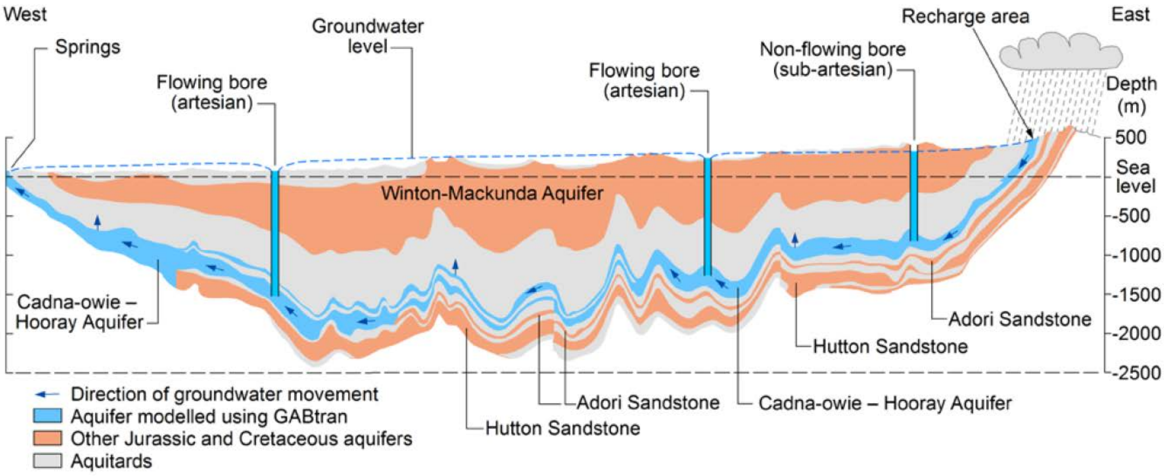
Sources: (A) Smerdon *et al*., 2012; (B) Geological Survey of Queensland, 2016

Figure 23 (A) Geographic extent of the Great Artesian Basin (GAB) with indication of potential for hydraulic connection between the base of the GAB and the top of the underlying basement sequences; (B) Shale gas and oil prospective areas in Queensland

Much scientific study has been undertaken to improve understanding of the GAB and its aquifers. However, there are still knowledge gaps (Smerdon *et al*., 2012). Key knowledge gaps identified by the GAB Water Resource Assessment project (Smerdon *et al*., 2012) relevant to the impacts of shale gas and oil projects are:

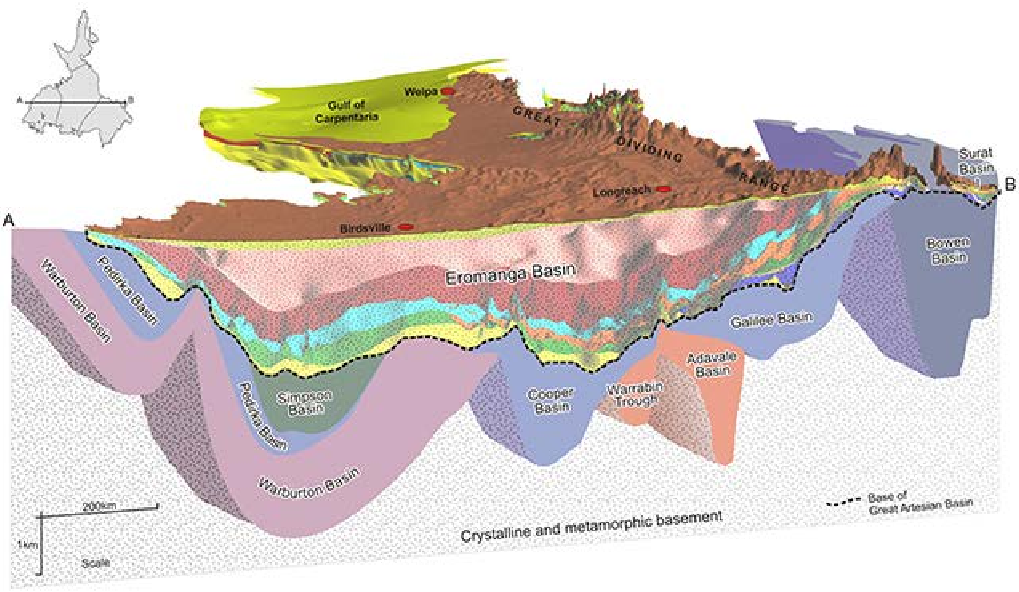
- the quantification of the hydraulic connection between the GAB and (i) underlying and adjacent geological basins, and (ii) overlying geological basins and shallow groundwater systems
- the effects of geological structures on groundwater flow in the GAB
- groundwater levels in the central Eromanga Basin, where existing data are sparse
- the hydraulic properties of aquitards in the GAB
- processes and variability in vertical leakage/cross-formational flow
- understanding of the Winton–Mackunda aquifer.

The GAB is a large and complex system, and one of the impediments to fully understanding its water resources is the sparsity of data. Improving understanding of the GAB will be important in understanding the impacts of shale gas and oil projects on these groundwater systems.



Note: The GABtran modelled aquifer is shaded blue; other GAB aquifers are shaded orange.
Source: Welsh *et al*., 2012

Figure 24 Cross-section of the Great Artesian Basin aquifers



Note: This diagram shows aquifer layers of the Great Artesian Basin (GAB) and underlying geological basins. Some of the GAB aquifers may be in contact with groundwater in underlying basins.
Source: Smerdon *et al*., 2012

Figure 25 Three-dimensional illustration of a slice through geological basins, including the Eromanga Basin that hosts the Great Artesian Basin

4.2.2 Water use in shale gas and oil projects

There are many ways in which activities conducted in the shale gas and oil project life cycle can interact with surface water and groundwater resources. Sections 2.2 and 2.3 outline this life cycle and the way that water is used. Figure 26 shows where these interactions occur throughout this life cycle and how the interactions may impact on surface water and groundwater resources.

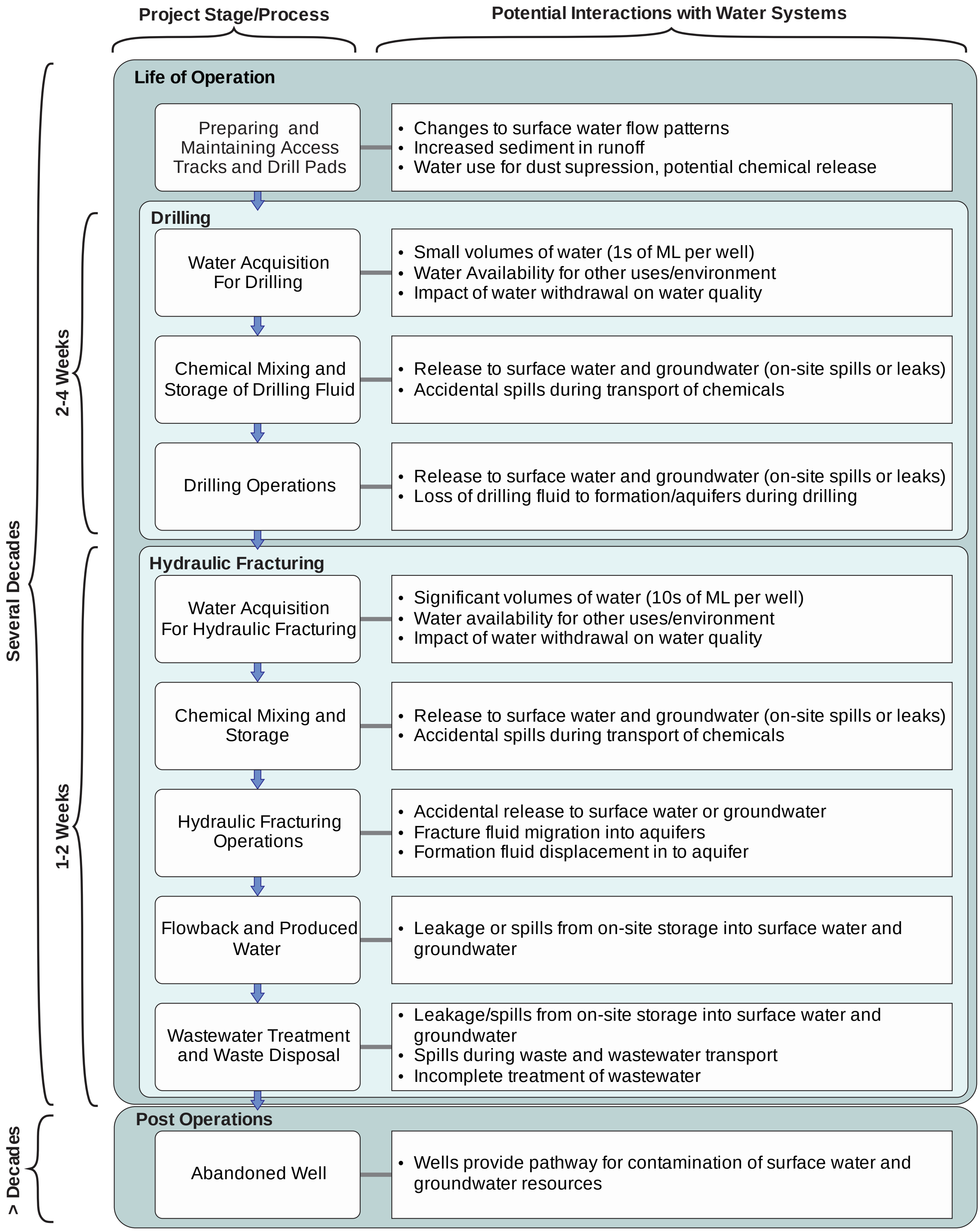
During the early stages of the life cycle, preparation of access tracks, well pads and other infrastructure may interact with surface water features, thus altering surface flow patterns. Dust suppression on unsealed access tracks, roads, well pads and laydown yards will also consume water. These infrastructure developments are likely to be in place throughout the life of a project.

The most intensive uses of water occur during drilling and hydraulic fracturing operations (see Sections 2.4 and 2.5). Total volumes of water used during drilling are around 0.5 ML per well. Hydraulic fracturing uses 5–20 ML per well over the course of days to weeks. Water may be trucked or piped to the well pad if no local source is available. Availability of water for hydraulic fracturing will be an important part of the supply chain for shale gas and oil. The quality of the water is important. Low-salinity water is preferable; however, studies by both the Council of Canadian Academies and the Australian Council of Learned Academies report efforts by industry to reduce reliance on fresh water, with methods such as water recycling and the use of saline water under development (Cook *et al*., 2013; Council of Canadian Academies, 2014). In addition to water, additives for drilling and hydraulic fracturing will be transported to the site.

Once drilling is complete, this drilling fluid will need to be disposed of. The water may be trucked to a treatment facility, or a mobile treatment facility could be used. Treated water may be reused, released to the environment or disposed of underground. The waste removed through the water treatment process would be disposed of in a waste treatment facility. See Chapter 6 for further discussion of waste management.

Once hydraulic fracturing is completed, flowback water will flow to the surface (see Sections 2.3 and 2.5.2). Typically, the hydraulic fracturing fluid recovered from shale formations as flowback ranges from 25% to 75% (Cook *et al*., 2013); the rest remains underground within fractures and pores within the rock formations. The flowback water contains the chemicals added to the hydraulic fracturing fluid (see Section 2.5), as well as components present in the formation water. The initial composition will be close to that of the hydraulic fracturing fluid but will become gradually more dominated by the formation water. Chemicals added to fracturing fluids may also break down in the subsurface, or react with the formation or formation water. During the production stage, each well will continue to make a small amount of produced water. As for the drilling fluid, flowback and produced water will need to be treated before it can be disposed of, in most cases.

At the end of the life of a well, it will be plugged and abandoned. Cement ‘plugs’ will be placed within the well to prevent vertical movement of fluid, and the top of the well will be capped. The steel casing in the well will remain in place.



Source: Modified from US Environmental Protection Agency, 2011

Figure 26 Water use and potential interaction with shallow water and groundwater systems throughout the life cycle of shale gas and oil well operations

4.3 Impacts

Potential impacts of the life cycle of shale gas and oil resources on surface water and groundwater systems fall into three broad categories:

- water-use impacts, related to the extraction of water from surface water and/or groundwater sources for use during the development of shale gas and oil resources
- surface and shallow water contamination, related to the contamination of surface water and shallow groundwater as a result of handling water and chemicals, typically at the surface
- down-hole impacts, related to the contamination of surface water, shallow groundwater and deep groundwater as a result of contaminants, well integrity issues and naturally occurring elements migrating upwards.

The impacts identified are listed in Table 10, and are discussed in the following sections.

4.3.1 Water-use-related impacts

The taking of water from surface water or groundwater resources for shale gas and oil operations (Figure 22 and discussion in Section 4.2) may impact other uses of these water resources (see impacts WA.1 and WA.2 in Table 10), such as agriculture, drinking water or dependent aquatic ecosystems. Groundwater discharge to creeks and wetlands is required to maintain dependent ecosystems and associated ecological functions. Reductions in groundwater availability or changes to the flow regime may also indirectly impact surface water resources by reducing the level of water tables, as well as directly impacting the viability of water bores for human use. Additionally, changes in water quality can occur where groundwater pressure gradients and flow directions are altered, causing groundwater to flow from parts of the groundwater system that contain poorer quality water (Price, 1996).

The literature reviewed for this report concludes that individual well water requirements are not large in comparison with other water uses (Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014). Although cumulative impacts are not within the scope of this review, it is worth noting that the total annual water requirement of a shale gas or oil project drilling 100 wells per year would be about 2,000 ML. This is approximately 3% of the volume of water currently produced by the CSG sector in Queensland (from around 5,000 wells that are producing gas; see Section 2.3), and less than 0.1% of total water use in Queensland (see Section 1.2). If the water is recycled, or if a brackish-to-saline water source is used, competition with other water users would be reduced (Council of Canadian Academies, 2014, Pepper *et al*., 2018).

Although the overall volume of water use is not large in the context of total state-wide water uses such as agriculture, the possibility of local impacts from the use of water resources has been highlighted in reviews of the shale gas and oil sector (Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014; US Environmental Protection Agency, 2016a; Pepper *et al*., 2018). A good example of this is the finding of the Hawke inquiry (2014) in relation to water use, which states ‘Unconventional gas extraction has water requirements for drilling and hydraulic fracturing that are small in the context of many other licenced water uses, but which need to be managed carefully to ensure sustainability at a local or catchment/aquifer scale. Conflict with other water users can be reduced by the use of saline ground water or recycled water where feasible (executive summary, page xv)’. In the context of the resources in inland Queensland where the GAB may be used as a source of water, 2,000 ML would equate to approximately 0.5% of the total annual use from this basin (see Section 1.2). If this volume were sourced from a small number of wells over a limited area, local impacts may be more significant.

4.3.2 Water-contamination-related impacts (WA.3 to WA.11)

Water resources may be impacted as a result of contamination. In this context, contamination means the introduction of substances to the water system as a result of human activity, and pollution is the result of widespread contamination (Price, 1996). There are numerous ways in which activities in the shale gas and oil project life cycle can result in contamination of water. Figure 26 and the discussion in Section 4.2 outline the ways in which these activities may interact with water systems, and Figure 22 shows the potential impact modes. The impact modes are generally through subsurface flow from surface sources to wells, springs, wetlands and rivers. Surface spills may directly enter surface waters. In arid environments with little to no surface water, such as those in inland Queensland, spilled fluid is more likely to infiltrate the soil, where it may enter shallow groundwater systems (if present). However, where no shallow groundwater is present, migration downwards of contaminants from surface spills may not reach groundwater resources. Water in shallow groundwater systems may be linked to groundwater-dependent ecosystems. Impacts may take time to become evident because of the slow rates at which water travels through the ground. Groundwater in the intermediate and deep zones shown in Figure 22 is unlikely to be impacted by surface spills (Council of Canadian Academies, 2014).

Impacts related to the contamination of surface water and groundwater resources, and the pathways that result in this contamination, are well covered in the literature (New York City Department of Environmental Protection, 2009; Broomfield, 2012; Cook *et al*., 2013; Warner *et al*., 2013; Council of Canadian Academies, 2014; US Environmental Protection Agency, 2016a). These potential impacts are summarised in Table 10 (impacts WA.3 to WA.11) and are discussed in more detail below:

- *Incidental spills on the surface during the transport and handling of chemicals (impact WA.5).* Chemicals used in drilling and hydraulic fracturing fluids will need to be transported to well pads. There is a risk that these chemicals could be spilled during transport, loading or unloading, or while in storage or being used. This also applies to fluids such as diesel and hydraulic oils that are transported and used at well pads. The risks associated with these will be similar to the risks posed with transporting any industrial chemical (e.g. pesticides used in agriculture). The intensity of the impact will depend on the form of the chemical (solid or liquid); the composition; the size of the spill; and the effectiveness of controls, clean-up and remediation methods.
- *Incidental spills on the surface from storage ponds, tanks, pipelines, wellhead etc. (impacts WA.5 to WA.9 and WA.11)*. Drilling and hydraulic fracturing fluids, once mixed, will be temporarily stored in tanks or ponds at the drilling site, as will flowback and produced water. Drilling and hydraulic fracturing fluids contain predominantly water with a mixture of materials and chemicals. Flowback water contains a mix of hydraulic fracturing fluid and formation water (groundwater), and produced water will be formation water. The fluids will be pumped through pipes on the sites, particularly during hydraulic fracturing. In the event of a pipe rupture resulting in a spill – depending on the volume of water released and soil moisture conditions (e.g. from rainfall), subsurface conditions and depth to groundwater – the contamination may be limited to the soil horizon and never reach the groundwater table. The likelihood of groundwater contamination becomes higher in impermeable soil areas where there is shallow groundwater and when relatively large spills occur. The intensity of the impact will depend on the composition of the fluid; the size of the spill; and the effectiveness of controls, clean-up and remediation methods.
- *Infiltration of water into soil due to dust suppression (impact WA.10).* Before drilling of wells, access tracks and the drilling pad need to be prepared. This usually involves removal of vegetation and topsoil from the site and replacement with a gravel base, or levelling of the ground surface. In either situation, dust generation at the site and access roads will need to be controlled; this is typically by regular water spraying. Once a well site is in full production, the need for dust suppression no longer exists because the

soil surface will have been covered and the site will require limited access. Dust suppression would be required whenever access tracks are used intensively (during a well workover, for instance). The intensity of the impact will depend on the composition of the water used for dust suppression and the amount of water used (US Environmental Protection Agency 2016a, Tasker *et al* 2018).

- *Overflow or containment failure from storage basins or ponds, dam wall collapse, and runoff to wetlands and rivers (impact WA.11)*. Flowback water and hydraulic fracturing fluid stored in storage basins and ponds may be released in flooding events if overtopped or as a result of failures in the construction of the basins/ponds. Ponds are typically located in areas that are less prone to flooding; for instance, the CSG industry locates ponds in areas with average flood recurrence intervals of 1 in 2,000 years (Golder Associates, 2009). Releases during flood events will be diluted by the floodwaters but may cause downstream impacts. Releases due to the failure of the containment (not related to flooding) may result in local contamination of surface water or groundwater systems. Any such event would be accidental or the result of an extreme weather event.
- *Release of concentrated residue in storage ponds (impact WA.12).* Evaporation will result in the concentration of contaminants in a storage pond. The increased concentration of materials such as salts, metals and NORM may increase the intensity of the impact of any spill, while also reducing the extent of possible spills (due to the reduced volumes). Concentration of these contaminants may also occur if hydraulic fracturing fluids and flowback water are recycled.
- *Disposal of treated wastewater (impact WA.3 and WA.4).* Flowback water, produced water and unused hydraulic fracturing fluids will most likely be treated. This will create treated water that will need to be managed or disposed of, as well as associated waste materials. Treated water may be recycled and reused for drilling fluid or hydraulic fracture fluids, or released to the environment. Releases could be in surface water systems, groundwater reinjection or beneficial reuse (e.g. irrigation, dust suppression). However, management of releases of water may have an impact if the quality of the water is not compatible with the end use (excess contaminants, or mobilisation of materials in the environment in which it is used). These impacts would most likely arise as a result of errors in the design of the treatment process, failure of monitoring systems or failures in the treatment plant.

Chemical contaminants

One of the key considerations in evaluating impacts related to the contamination of surface water and groundwater resources is the nature of the contaminant. The contaminant could be relatively benign, causing only nuisance impacts, or highly hazardous to users of the water resource or ecosystem. Other considerations are the concentration of the contaminant, its persistence in the environment and the size of the spill or release.

The additives used in drilling and hydraulic fracturing operations are outlined in Section 2.5.2. The mix of additives used will vary on a case-by-case basis, depending on local geological conditions and the engineering requirements of the operation. Some of these additives, such as bentonite clay in drilling fluids and guar gum in hydraulic fracturing fluids, are used in wine-making and as a food additive, respectively. Other components, such as the biocides used in hydraulic fracturing, are toxic (although the biocides used do break down in the environment) (NICNAS, 2017a). The industry has been moving to develop hydraulic fracturing additives with low or no toxicity, or that degrade rapidly (Cook *et al*., 2013).

The consistent conclusion that can be drawn from major reviews of the shale gas and oil sector (Broomfield, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014; US Environmental Protection Agency, 2016a; Pepper *et al*., 2018) is that intense impacts from drilling and hydraulic fracturing operation are most likely a result of inadvertent surface spills during the preparation and handling of drilling and hydraulic fracturing fluids. The spatial extent of these impacts will be limited, with a scale of tens of square metres, and will be of a short duration. Further, the studies find that, in a well-regulated industry operating at high standards, these incidents will be infrequent.

Unlike the potential contaminants in drilling and hydraulic fracturing fluids that are from additives, the contaminants found in flowback and produced water will depend regionally on the components of the deep strata from which these waters come. The flowback and produced water will include petroleum hydrocarbons (including BTEX) and trace metals, and may include NORM, which may be naturally present in the formation and/or in the Kerogen and condensate. Developing an understanding of the composition of flowback and produced water may not be possible until the early stages of resource development. Defining the composition of these waters will be important at a regional scale to design appropriate monitoring (Council of Canadian Academies, 2014).

Water quality of flowback and produced water

In terms of water quality issues, the composition of the waters returned to the surface is of critical importance. Flowback waters contain not only residual hydraulic fracturing chemicals but also components released from the shale formations in contact with hydraulic fracturing fluids and formation waters. Flowback water starts with primarily the same composition as hydraulic fracturing fluid, although some of the components may react or be consumed during hydraulic fracturing (e.g. acids react with the formation, and proppant is held in the formation to keep the fissures open). The flowback water will then contain an increasing proportion of the formation water as the well is flowed. Eventually, the flowback water will be made up entirely of formation water. The distinction between the final stages of flowback and produced water is related to the engineering stage.

Flowback water is fluid initially flowing from the well at a rate of up to 1,000 L per minute immediately following hydraulic fracturing, decreasing to 160,000 L per day after 24 hours and continuing to decrease to around 500 L per day over a period of a few weeks (Cook *et al*., 2013). During this period, hydrocarbons (gas, condensate and/or oil) will also start to flow, and at that stage the well will be converted to production. Formation water brought to the surface during production is known as produced water (or associated water). Pumping or artificial lift may be required to increase hydrocarbon production, depending on pressures in the reservoir.

Typically, the formation water may contain:

- major ions
- trace metals
- inorganic ions
- organic compounds
- NORM.

The composition of formation waters will vary between geological formations, but work in North America has observed general trends in the data. Typically, these waters are highly saline, with major cations including sodium, calcium, barium, strontium and magnesium, and major anions including chloride, sulfate and bicarbonate (Haluszczak *et al*., 2013). Formation waters may contain appreciable amounts of other dissolved ions as well, including magnesium, strontium, barium, uranium, radium, arsenic, vanadium and molybdenum (Renock *et al*., 2016). Importantly, hydraulic fracturing fluids may mobilise these elements (Renock *et al*., 2016). Haluszczak *et al*. (2013) also reported elevated concentrations of several potentially toxic trace elements such as arsenic, mercury and zinc.

Very little data are available in the literature, but dissolved organic carbon concentrations in produced water appear to be quite high, although one study concluded that shale gas and oil produced water does not contain significant quantities of polyaromatic hydrocarbons, thus reducing the potential health hazard (Maguire-Boyle and Barron, 2014). However, soluble aromatic and aliphatic compounds (including BTEX) will be present in the water as a result of dissolution of constituents within the shale, and partitioning from shale oil and condensate into the produced water. These dissolved hydrocarbon concentrations would typically require specialist treatment or management.

Another component of shale gas and oil formation waters is potentially NORM. Shales can contain elevated concentrations of potassium-40, uranium-238 and thorium-232, all of which are radioisotopes. Uranium and thorium decay leads to the presence of radium isotopes (radium-226 and radium-228) and their decay products, including radon gas, in produced water. The reducing and highly saline conditions in shale formations enhance mobilisation of radium from the host rocks to formation waters (Lauer and Vengosh, 2016). Unlike uranium and thorium, radium is relatively water soluble and may be released into the adjacent pore water, and into the flowback and produced water following hydraulic fracturing (Zhang *et al*., 2015). The majority of the literature is dominated by studies in the Marcellus and Utica Shale, where this is a key issue. The concentrations of NORM in Australian gas and oil shales is not well known, and it is uncertain whether this would be an issue in the produced water and/or just limited to precipitates and scale on equipment.

As noted above, the composition of formation water, and the range of possible compositions of drilling and hydraulic fracturing fluids highlight some of the uncertainty around the potential impacts on water from shale gas and oil–related projects. It is reasonable to assume that shale formations in Australia will contain highly saline water with a potentially complex chemistry. This observation was made by both Cook *et al*. (2013) and Hawke (2014). The chemistry of formation water in Australia's shale resources will not be known until further exploration work has been completed. The management and treatment of this water are similar to those used for other industrial and mining waters (Hawke, 2014).

Size and frequency of spills

The size of any spill will be important in determining the materiality of the impact. There is concern that spillage of these fluids could reach natural watercourses or infiltrate through soil to the watertable, resulting in contamination of drinking water aquifers (New York State Department of Environmental Conservation, 2011). Whereas leaks associated with storage tanks may be detected relatively rapidly and volumes of water spilled will be small, leaks in large storage pits or ponds may remain undetected unless a suitable leak detection system is in place or accurate water balance calculations identify otherwise unexplained water losses beyond natural evaporation. The volume of fluid from slow leaks such as this is unlikely to be large, unless water is stored in ponds for several years. The cumulative impacts of multiple leaks have not been considered. A study of spills at the well pad directly related to hydraulic fracturing conducted by the US Environmental Protection Agency (2015) characterised 151 spills of hydraulic fracturing chemicals or fluids, with data on the volume of these spills for 125 spills. The total cumulative volume of the spills was 697,000 L, with a median volume of 1,600 L and a maximum volume of 72,000 L.

The frequency of inadvertent spills and leaks will depend on the quality of the practices used in the transport, mixing and handling of the chemicals and fluids discussed above. The US Environmental Protection Agency (2015) study of spills found that spill reporting in the state of Colorado provided the most detail. In this state, they estimated the average rate of reported spills to be 1.3 per 100 hydraulically fractured wells. Cook *et al*. (2013) suggested lower frequencies for a range of spill mechanisms related to drilling and hydraulic fracturing, ranging from 1 in 1,000 for spills of stored hydraulic fracturing fluid or flowback water (80,000 L), to 1 in 5,100 for leaks of diesel from truck fuel tanks (1,135 L), to 1 in 4.5 million for a leak of concentrated liquid biocide (1,890 L). There are limited data on spills in the Australian oil and gas sector, although some CSG-related studies are discussed in Section 4.4.

Water treatment

The chemical composition of flowback and produced water (e.g. high salinity) means that it cannot be generally released into the environment (such as surface water or onto the ground), without some form of treatment. Treatment can involve transport of the water by truck to central treatment locations, and can include separation systems, and buffering using treatment chemicals. There is considerable experience in the oil and gas industry regarding water treatment, and beneficial use or reinjection of water (Sreekanth and Moore, 2015). In North America, the main treatment options are as follows:

- *Treatment at a wastewater treatment facility, followed by discharge into receiving waters.* Specialist wastewater treatment facilities may be required as urban wastewater treatment plants may not be able to treat flowback and produced water because of their composition, typically due to high salinities (Council of Canadian Academies, 2014). Desalination processes must be used and the most common desalination method is reverse osmosis. At very high salinities, reverse osmosis becomes less efficient, and thermal distillation may be preferred (Gregory *et al*., 2011). As well as producing treated water, these desalination technologies typically produce a concentrated brine that may be converted to solid waste, in either a crystalliser or evaporation ponds. Other steps in the treatment of brines are typically needed to remove metals and organics. An example is the addition of lime and sodium sulfate, which immobilises metals such as barium and radium, but not halides such as chloride and bromide. Once treated, the clean water may be released to the environment or applied to other uses, such as irrigation for agriculture.
- *Reinjection into groundwater*. The Council of Canadian Academies (2014) cites that the optimum practice in the oil and gas industry in North America for the disposal of wastewater is to inject it underground. The formations that are targeted for waste fluid injection are often depleted oil and gas reservoirs or saline aquifers because of their ability to accommodate large volumes of fluid (Council of Canadian Academies, 2014). There are risks associated with wastewater injection, including induced seismicity and leakage of wastewater to shallower aquifers (Cook *et al*., 2013). For reinjection to be viable, suitable formations must be present within a shale gas or oil project area, and this may not always be the case. For these reasons, both Cook *et al*. (2013) and Hawke (2014) point out that this option would require further investigation to test its viability in Australia.
- *Reuse of the water.* Reuse of flowback water as drilling and hydraulic fracturing fluids for other wells is a desirable outcome for the industry because it would reduce the volumes of water needed. However, a major problem with reuse of flowback water is the high concentrations of barium, calcium, iron, magnesium, manganese and strontium that can form scale (Kargbo *et al*., 2010). These constituents readily form precipitates, which can rapidly block the fractures in gas-bearing formations. NORM may also become concentrated as water is reused. These aspects mean that some form of water treatment will be required. While water reuse is an ongoing challenge for the shale gas industry, it is being actively explored and is likely to be important in the Australian shale gas and oil sector (Cook *et al*., 2013; Hawke, 2014).

Wastewater that is disposed of at the surface, into aquifers and for beneficial use (such as dust suppression) may need to be treated so that the water quality is compatible with the end use. The different treatment options for flowback and produced water are a source of uncertainty around the impacts of the shale gas and oil project life cycle. The various treatment and disposal options will have an influence on the volumes of water used, the amount and types of wastewater produced, and operational aspects of water handling. These factors will influence the materiality of impacts on water resources. An example of the different approaches is available in the data presented by Veil (2015), which show that in 2012 around 80% of flowback or produced water in Texas was disposed of in injection wells (48% for enhanced oil recovery) and around 15–20% was reused. In Pennsylvania, 72% of the flowback or produced water was reused, 13% was disposed of in injection wells, and up to 15% was treated and discharged or reused at the surface. In Queensland, produced water from CSG is also disposed of in various ways, including aquifer recharge, irrigation, dust suppression and release to surface water systems. Queensland CSG produced water is treated before recharge and irrigation disposal, with reverse osmosis used predominantly.

4.3.3 Down-hole-related impacts (WA.13 to WA.18)

Impacts WA.3 to WA.11 (Table 10) described in the previous sections are primarily related to water contamination that results from activities at the surface. Shale gas and oil developments will also interact with groundwater in the intermediate and deep zones shown in Figure 22 (see Section 4.2). The deep zone is essentially the groundwater in and around the target shale formation. This zone is the target for injection of hydraulic fracturing fluid. The intermediate zone includes groundwater systems between the shallow groundwater zone and the deep zone.

Although the general pathways by which water contamination has an impact on environmental values are well understood, the pathways for impact resulting from deep groundwater contamination are more complex. Impacts would generally require the migration of contaminated water or gases upwards to shallower depths where they can affect water resources that are accessed by other users and the aquatic ecosystem. There is currently a limited understanding of the potential migration pathways and time frames for these fluids to reach the surface (Council of Canadian Academies, 2014), making the assessment of these impacts difficult.

Upward migration of contaminated groundwater (saline formation or hydraulic fracturing fluids) requires an abnormal pressure gradient to drive the flow. As well as gases being considered a contaminant, the mechanisms for migration of dissolved gases will be the same as for other fluids. The main point of difference is that, when gases exist in the gas phase, they will be buoyant, driving vertical migration (Huddlestone-Holmes *et al* 2017).

The impacts that could occur in the intermediate and deep groundwater zones include those that result from an integral part of the normal shale gas project life cycle, including losses of drilling fluids to groundwater while drilling a well and incomplete recovery of hydraulic fracturing fluids from shale resources (deep groundwater) after stimulation. Impacts may also result from inadvertent events such as accidents or system failures, including fluid loss occurring during drilling and hydraulic fracturing operations. An additional type of impact may occur as a result of improper or poorly executed completion, decommissioning or abandonment of wells. These impacts are discussed further below:

- *Fluid losses as part of normal operations (impacts WA.13 and WA.14).* Drilling fluids are designed and managed to prevent their loss from the well during drilling. Limiting losses from the well prevents damage to the formations that are drilled and ensures that sufficient drilling fluid is returned to the surface to remove drill cuttings. The typical composition of drilling fluids, particularly the water-based drilling fluids most commonly used, makes them benign. Neither Cook *et al*. (2013) nor the Council of Canadian Academies (2014) raised the loss of drilling fluids as an issue. Inadvertent losses may occur if drilling fluids are not properly managed; however, impacts are likely to have low intensity, be of small scale and have a short duration.

  Hydraulic fracturing will involve the injection of large volumes of fluid into the target formation by design. Typical rates of recovery for hydraulic fracturing fluids are around 25–75% (Cook *et al*., 2013). For this fluid to have an environmental impact, it would need to come into contact with an environmental value, such as a groundwater system used by other users. This interaction would only occur where the shale resources are at depths close to groundwater resources used by others; this is unlikely because shale gas and oil resources typically lie much deeper than usable aquifers. An exception to this are the potential resources identified in the Eromanga Basin (Table 2) that are interbedded with aquifers of the GAB (Ransley and Smerdon, 2012; Smerdon *et al*., 2012). This relationship has been briefly discussed in the overview for this chapter; however, no attempts have been made to correlate areas that may be prospective for shale gas and oil developments with deep aquifer use. Developing an understanding of the relationship between these aquifers, targeted shale formations and water use will be important for understanding the impacts of shale resource development on deep groundwater resources.

Generally, *direct impacts* from hydraulic fracturing fluids that are injected into the targeted shale formation are expected to be limited. The long-term fate of these hydraulic fracturing fluids and related impacts are discussed below.

- *Fluid losses due to incidents during hydraulic fracturing, and migration of hydraulic fracturing fluid during or after hydraulic fracturing operations (impacts WA.14 to WA.18). Casing failures during hydraulic fracturing (impact WA.15) may result in fluid leaks into shallow or intermediate groundwater systems. Casing leaks can result from poor thread connections, steel corrosion, thermal stress cracking, or poor cementing of the casing (Wu et al., 2016). These leaks would be inadvertent and are likely to be quickly detected because they would most likely be accompanied by a loss of pressure in the well. Cook et al. (2013) and the Council of Canadian Academies (2014) did not consider risks related to well failure during hydraulic stimulation to be a significant issue.*

  Other pathways identified in Cook *et al*. (2013), Council of Canadian Academies (2014) and Reagan *et al*. (2015) leading to potential impacts during hydraulic fracturing operations are:

  - hydraulic fracturing fluids intersecting other wells (during or after hydraulic fracturing operations), allowing upward migration of fluids (impacts WA.16 and WA.17)
  - hydraulic fractures extending vertically, intersecting shallower groundwater resources; hydraulic fractures intersecting pre-existing fractures; and faults allowing fluid migration to shallower groundwater resources.

  Examples of these pathways are shown in Figure 22. Impacts WA.15, WA.16, WA.17 and WA.18 result from liquid and gas movement from the reservoir to drinking water resources via the production well, or other wells (other production wells or abandoned wells from other developments) near hydraulic fracturing operations. Dusseault & Jackson (2014) conclude that the migration of hydraulic fracturing or formation fluids (including natural gas) to the surface as a result of deep hydraulic fracturing of typical shale gas reservoirs appears most unlikely, except when abandoned or suspended wells are intersected by the hydraulic fracturing fluids during the high-pressure stage of fluid injection.

  Producing wells situated in the same target formation as new wells involved in fracture stimulation may also be affected by hydraulic fracturing fluids when the inter-wellbore distance is within approximately 250 m. If offset wells (wells drilled near an existing well to monitor fracturing and gas production) are not able to withstand the stresses applied during the hydraulic fracturing of a neighbouring well, certain well components may fail (typically the cement components), which could result in a pathway up to the surface, followed by release of fluids. The US Environmental Protection Agency identified 10 incidents in which surface spills of hydraulic fracturing–related fluids were attributed to such well communication events (US Environmental Protection Agency, 2015).

  Dusseault & Jackson (2014) also note that the quality of cement completions of casing installations is a concern with regard to future gas migration. They found that gas migration outside the casing is typically a result of incomplete cementing (in the case of older conventional wells) or the formation of micro-annuli within, or on the periphery of, the cement sheath because of cement shrinkage. Gas pressure gradients will promote the vertical ascent of gas slugs that will appear at the surface as pulsed gas flow. If such gas flows are not allowed to discharge to the atmosphere by shutting-in surface valves, potential for gas migration and subsequent groundwater contamination is exacerbated. Some of this leakage may be of natural gas in intermediate zones between shallow aquifers and the target shale gas formations intersected by the well.

  Recent studies by Wu *et al*. (2016) and Huddlestone-Holmes *et al*. (2017) provide a thorough review of well failure mechanisms and implications for inter-aquifer connectivity. They discuss cement seal failure that occurs when the cement shrinks, develops cracks or channels, or is lost in the surrounding rock formation during application as the main causes for the loss of integrity of the seal around a wellbore.

Recent evidence indicates that the risk of properly injected hydraulic fracturing fluids contaminating potable groundwater (by upward migration of new fractures or flow along existing fractures and faults) is remote if separation distances between the formation being hydraulically fractured and potable aquifers are adequate (Davies *et al*., 2012; Fisher and Warpinski, 2012). Preliminary indications are that appropriate separation distances are in the order of 600 m (Broomfield, 2012), although this will depend on local conditions.

A more likely scenario where migration of hydraulic fracturing fluids to drinking water resources may occur is where oil and gas resources coexist with drinking water resources (e.g. the Eromanga Basin and GAB). Currently, the overall frequency of this in practice appears to be low. Little information is available on the long-term human and ecosystem health risks posed by migration of hydraulic fracturing fluids to the surface (Broomfield, 2012); therefore, an assessment of the intensity of these impacts is difficult. The Council of Canadian Academies (2014) also state that there is currently a lack of information on the potential long-term human and ecosystem health risks posed by the potential migration of hydraulic fracturing fluids to the surface, and the time scales involved are of the order of decades to hundreds of years. Furthermore, the natural attenuation of hydraulic fracturing chemicals in the subsurface will also reduce their concentrations (Council of Canadian Academies, 2014). Chapter 7 discusses possible human health impacts further.

A recent study by Reagan *et al*. (2015) reported on numerical simulations of water and gas transport between a shallow tight gas reservoir (characterised by an ultralow permeability in the range of a nanodarcy) and a shallower freshwater aquifer following hydraulic fracturing operations. Two general failure scenarios were considered in the simulations, in which connection between the reservoir and aquifer is assumed to occur (i) via a fracture or fault, or (ii) via a deteriorated, pre-existing nearby well (Figure 22). The study used generalised representations of single-well, single-pathway tight and shale gas systems to identify the processes and parameters that could lead to rapid gas transport from such formations to groundwater resources.

Although Reagan *et al*. (2015) highlight the need for additional research to better understand the risk from hydraulic fracturing, they argue that pathways created by hydraulic fracturing into pre-existing pathways cannot be discounted. Examples of the latter include naturally formed pathways (permeable fractures or faults) or artificial pathways (abandoned, degraded, poorly constructed or failing wells). Reagan *et al*. (2015) also acknowledge that the possibility of human error in the construction and operation of wells cannot be ignored. Evidence for the existence and impact on groundwater of these artificial pathways was provided by Dusseault & Jackson (2014), and Jackson *et al*. (2013).

4.4 Comparison with coal seam gas development

Although the processes involved in CSG and shale gas and oil extraction are to a large degree similar, there are important differences. These differences have been discussed in Sections 2.3 and 2.4. Some of these differences will mean that the impact on water resources will be potentially either decreased or increased over a shale gas and oil project life cycle compared to CSG.

There are two primary differences. The first point of difference is the need for hydraulic fracturing and the scale of hydraulic fracturing when it is conducted. Hydraulic fracturing operations will be an integral part of shale gas and oil developments, whereas they have been conducted on less than 10% of CSG wells so far (Stone, 2016). The scale of hydraulic fracturing operations is also typically much greater for shale gas and oil wells. The result is that the shale gas and oil project life cycle will use more water than the CSG project life cycle.

The second point of difference is that CSG reservoirs contain significantly more formation water than shale resources. This water must be removed (more precisely, the water pressure must be reduced) to allow gas to desorb from the coal. As a result, CSG operations will involve significantly greater volumes of produced water than shale gas and oil operations, whose reservoirs contain only small volumes of water. A comparison of the impacts on water resources of CSG and shale gas and oil projects follows.

4.4.1 Coal seam gas water-use-related impacts

The volume of water required to hydraulically fracture shale gas strata can be an order of magnitude larger than that for CSG, depending on well depth and the extent of horizontal drilling (Cook *et al*., 2013). As a result, the volumes of water required and flowback water are likely to be greater for shale gas and oil than for CSG. A mitigating factor is that shale gas and oil developments may be able to select water resources in a way that minimises this impact. An example would be to source water from deep brackish to saline aquifers that are not accessed (and potentially unusable) by other users. The location of Queensland's shale resources will also have an influence on these impacts – the majority are in remote regions with arid to semi-arid climates. The land uses in these regions do not use water as intensively as the agricultural land uses coincident with the CSG sector in the Surat Basin (shale resources in the Bowen and Maryborough basins may be coincident with these more intensive agricultural practices).

Although the volumes of water used during the development stages of shale gas and oil projects will be greater than the volumes used in the same stages of CSG projects, these volumes will still be significantly less than the volume of water produced during the CSG production stage. As well, CSG water production can be from aquifers that are in contact with those used by other users. Shale gas and oil will produce very small volumes during production, and this water is typically produced from very deep formations. As a result, the cumulative impacts on groundwater resources due to extraction of water across the whole project life cycle may conceivably be higher for CSG projects than for shale gas and oil projects.

CSG activities do interact with existing wells that have been drilled as water bores, or legacy boreholes drilled as part of coal resource exploration activities. CSG operators have make-good obligations where water bores are affected. The Department of Natural Resources, Mines and Energy has a protocol for managing uncontrolled gas emissions from legacy boreholes (Queensland Department of Natural Resources, Mines and Energy, 2013).

4.4.2 Coal seam gas water-contamination-related impacts

The National Assessment of Chemicals Associated with Coal Seam Gas Extraction in Australia (the CSG Chemicals Assessment) was commissioned by the Australian Government in June 2012 in recognition of increased scientific and community interest in understanding the risks of chemical use in this industry. The assessment was completed in 2017. The CSG Chemicals Assessment aimed to develop an improved understanding of the occupational, public health and environmental risks associated with chemicals used in drilling and hydraulic fracturing for CSG in an Australian context.

The research assessed and characterised the risks to human health and the environment from surface handling of chemicals used in CSG extraction during the period 2010–12. This included the transport, storage and mixing of chemicals, and the storage and handling of water pumped out of CSG wells (flowback or produced water), which can contain chemicals originating from coal seam formations (Mallants *et al*., 2017b) and chemical residues from the hydraulic fracturing operation.

The CSG Chemicals Assessment examined 113 chemicals used by companies in Australia between 2010 and 2012 in drilling and hydraulic fracturing for CSG. Industry reports that 59 of the 113 chemicals that were being used in CSG extraction in 2010–12 were still being used in 2015–17. Despite the short reporting period of chemical use by the CSG industry (2010–12), the data from an industry survey (NICNAS, 2017a) still provide a good cross-section of the type of chemicals used for hydraulic fracturing. The focus is on the impacts of surface discharges (spills or leaks) on surface water and near-surface groundwater, extending to potential downgradient effects on surface water through overland flow or discharge of the shallow groundwater into surface waterways. The reason for this priority is that international studies have shown that the greatest risk to human health and the environment is from spills or releases of chemicals during surface activities, such as transport, handling, storage and mixing of chemicals (The Royal Society and Royal Academy of Engineering, 2012; Vidic *et al*., 2013).

The risks of chemical use are likely to be greatest during surface handling because the chemicals are undiluted and in the largest volumes (Mallants *et al*., 2017c). The risks associated with injection of hydraulic fracturing fluids in deep underground coal seams (Australia), or shale or tight gas formations (North America), on the other hand, have been shown to be very small, mainly because of geological factors that control vertical hydraulic fracture growth out of the gas formations, and proper design and monitoring of the hydraulic fracturing process (Dusseault and Jackson, 2014; Engelder *et al*., 2014; Mallants *et al*., 2017d).

A review of Australian CSG literature has identified several contamination pathways from surface spills through soil and shallow groundwater to several potential receptors, such as rivers, water wells, wetlands, springs and groundwater fauna (Mallants *et al*., 2017a). Additional potential pathways were also identified for deeper aquifers. The following list summarises the most frequently reported pathways associated with the use of drilling and hydraulic fracturing chemicals based on current Australian work practices (i.e. chemical handling, storage, transport, mixing and injection; and management of flowback and produced water from CSG wells):

- incidental spills on the surface from storage tanks, trucks, valves, and so on
- releases from supply and discharge lines and hoses
- infiltration into soil from storage basins, dams or waste disposal sites due to leakage and flooding.

Mallants *et al*. (2017c) reported that, between 2009 and 2013, the majority of compliance-related incidents from gas extraction in Australia were spills involving the release of CSG water (i.e. flowback and/or produced water) during operations. Most incidents occurred during the pre-operational phase and the de-pressurisation phase (the period during which gas is extracted and co-produced water requires management). The incidents had a probability of less than 1% for each phase, which is considered exceptionally unlikely using calibrated uncertainty language (Mastrandrea *et al*., 2010). Moreover, environmental consequences were reported to be minor (Queensland Department of Environment and Resource Management, 2011). A total of 48 compliance-related incidents were reported in 2009–13, mainly in Queensland (34) and New South Wales (4). For 10 additional incidents, the location was not provided (NICNAS, 2017a). These 48 compliance-related incidents involved:

- spills involving the release of CSG water (i.e. flowback and/or produced water) during operations (30)
- discharge (controlled or uncontrolled) of CSG water to the environment (5)
- overflow during flooding (7)
- exceedance release limits (3)
- other types of contamination (1)
- leaks through pond liners (2).

Although 30 spills of hydraulic fracturing fluids, and flowback and/or produced fluids from surface impoundments have been reported, the degree of detail with which those cases are described is generally insufficient to provide reliable quantitative data for input to exposure assessments.

Mallants *et al*. (2017a) collected preliminary data on chemical compositions of produced water to provide insight into the type of naturally occurring chemicals and their concentrations. Produced water was shown to contain metals and metalloids, organics (such as polycyclic aromatic hydrocarbons), and radionuclides extracted from the coal seam. Several of the metals and metalloids (i.e. arsenic, barium, boron, cadmium, chromium, copper, lead, manganese, molybdenum) measured in some CSG produced water samples had concentrations exceeding the *Australian drinking water guidelines* (NHMRC and NRMMC, 2011). These findings underscore the need for future assessments to include naturally occurring chemicals as a source of potential contamination, when leakage of flowback and produced water is considered.

The CSG Chemical Assessment found that the majority of chemicals were unlikely to cause harm to the environment when used in CSG extraction, even if they were to spill or leak in high volumes. It is in the event of a transport spill, or where untreated wastewater containing chemicals is reused for irrigation or dust suppression that certain chemicals have the potential to cause harm to the environment (Department of the Environment and Energy, 2017a).

The conceptualisation stage of the CSG Chemical Assessment involved developing conceptual exposure pathway models to estimate releases, consider environmental fate, and derive predicted environmental concentrations in soil and shallow groundwater from surface handling – for example, site spills, and overflows and leaks from surface ponds (Mallants *et al*., 2017c). The conceptual exposure pathway models were next used to develop modelling tools with which concentration distributions in space and time, and travel times for environmental contaminants could be determined for specific, realistic, conservative (after US Environmental Protection Agency, 1992) exposure scenarios and modelling assumptions. The latter were identified as reflective of particular geographic regions in which CSG operations are being (or proposed to be) conducted.

The CSG Chemical Assessment conducted risk assessments that addressed health risks (see Section 7.3.1) and environmental risk. The risk assessments found that the greatest pre-mitigation risk of harm to the environment was in the event of a large-scale transport spill (Department of the Environment and Energy, 2017a).

The package of products from the CSG Chemical Assessment includes a national guidance document (in consultation draft stage at the time of writing), which provides world-leading practice advice on approaches for human and environmental risk assessments for the coal and CSG industries (Department of the Environment and Energy, 2017b). In particular, the new risk assessment guidance specifies that naturally occurring geogenic chemicals mobilised by drilling or hydraulic fracturing, and found in drilling fluids and drilling muds, flowback and produced water, brines, and treated water, should be included as an essential component of any risk assessment. Also included are recommendations for direct toxicity assessments of complex mixtures, such as hydraulic fracturing fluids and produced waters, where use of toxicity values for individual chemicals may either overestimate or underestimate the toxicity of the mixture. The approaches outlined in this guidance document could be readily adapted for development of any onshore shale gas industry.

The impacts described here for CSG development are very similar to those outlined for shale gas and oil developments. The primary difference is that the volume of hydraulic fracturing–related chemicals and fluids used in shale gas and oil developments, and the frequency of use, are greater in shale gas and oil developments. This results in greater potential for inadvertent surface spills and leaks for shale gas and oil on a per-well basis.

Shale gas and oil projects generate smaller volumes of produced water than CSG projects. Potential leaks or spills of produced water and associated impacts are therefore likely to be less for shale gas and oil projects. However, it is noted that levels of contaminants in shale gas and oil produced water may be greater than those in CSG water, and so impacts could be more significant.

4.4.3 Coal seam gas down-hole-related impacts

Potential impacts related to wells for CSG and shale gas and oil resources are similar. The drilling processes are alike, and the possibilities of drilling fluid losses to aquifers are considered equally likely. Shale gas and oil wells are typically deeper and take longer to drill than CSG wells, potentially providing a longer window of opportunity during construction for incidents to occur. However, in both CSG- and shale-related drilling activities, the shallow aquifers through which the wells pass are cased off and cemented to protect them from possible impact, while deeper parts of the well are being drilled.

The potential frequency of impacts resulting from hydraulic fracturing fluids entering shallower groundwater systems during or after hydraulic fracturing is likely to be greater in shale gas and oil developments than in CSG developments, because hydraulic fracturing is more frequent and more intense. However, where hydraulic fracturing is used in CSG, the potential impact may be greater because the target horizon is typically shallower (compared with shale resources) and may be closer to producing aquifers that are exploited by other users.

Impacts related to long-term shale gas and oil well integrity are broadly similar to those of CSG developments (Wu *et al*., 2016). Well completion techniques are also similar, using multiple cemented steel casing.

4.5 Relevant regulations

The regulation of petroleum activities to prevent or mitigate potential water-related impacts is primarily through the requirements of the EP Act to protect water values and the Water Act that regulates licencing of water use and the impacts of water extraction by the resources sector on other users. The P&G Act authorises petroleum authority holders to take water in certain circumstances. Produced water is considered to be a waste material and must be managed in accordance with the Waste Act. The EA for a project will contain conditions related to water that the project must comply with. There are conditions for protecting water values in the streamlined model EA conditions for petroleum activities (Queensland Department of Environment and Heritage Protection, 2016a), as well as model conditions for regulated structures, such as dams or levees (Queensland Department of Environment and Heritage Protection, 2016b).

4.5.1 Regulation of water-use-related impacts

As for mineral and petroleum resource rights, all rights to the use, flow and control of all water in Queensland are vested in the State. The extraction of water for petroleum activities may be authorised for shale gas and oil activities through for the P&G Act or the Water Act:

- The P&G Act provides an authority holder with limited rights to take underground water for petroleum activities when it is necessary or unavoidable to take that water during the drilling of wells or the production of gas and oil. For shale gas and oil activities, this will mainly be produced water. Chapter 3 of the Water Act sets out the requirements that the authority holder must meet when exercising these rights.
- Access to, or interference with, water resources requires authorisation under Chapter 2 of the Water Act, which applies to most users of surface or underground water resources in Queensland.

The low volumes of produced water expected from shale gas and oil resources means that most of the water required for shale gas and oil activities will not be taken (or produced) as part of the shale gas and oil activities and will need to come from other sources, requiring shale gas and oil operators to seek authorisation as set out in Chapter 2 of the Water Act, or to purchase water from water suppliers.

Water authorities under the Water Act

The authorisation for shale gas and oil activities is likely to be in the form of a water licence or a water allocation (water permits may also be used, but they are generally a temporary authorisation that must have a reasonably foreseeable conclusion date). In granting a water licence, the regulating authority (the DNRME) needs to consider any water plan that applies for the affected water resource. Water plans are developed to provide for the sustainable management of water resources in a region, balancing the needs of water users and the environment. They are developed based on technical assessments and community consultation, and outline the objectives for managing water resources in the part of Queensland covered by the plan, and how these objectives will be achieved. Water plans also set out processes for granting water licences or water permits, and for the trading of water allocations. The taking or interfering with overland flow water or underground water may be limited by a water plan. Most of Queensland's prospective shale gas and oil resources are in areas covered by a water plan

If a water plan does not apply, then there are a range of things that the regulating authority must consider when granting a water licence (or water permit), including:

- existing water entitlements
- impacts on natural ecosystems and physical integrity of watercourses, lakes, springs and aquifers
- water resource management strategies in the area
- the public interest.

Water allocations may be granted from an unallocated water release process (e.g. public auction, tender, fixed price), or via a water planning process that converts an existing water licence into a tradeable water allocation. A shale gas and oil operator could seek also to temporarily or permanently trade a water allocation. Water allocation trading is well established in Queensland, and may include the permanent transfer or lease of an allocation to another party, or it may relate to other transactions such as subdividing or changing the location of an allocation. Formal approval may be required for some water trading, and a permanent trade always requires registration on the Department of Natural Resources, Mines and Energy Water Allocations Register. Trade rules are generally set out in water management protocols, or the Water Regulations 2016.

Works that take or interfere with water, such as the development of a borefield, may also need approval under the *Planning Act* 2016 as an assessable water development. Assessable developments require a development permit and approval from the State Assessment and Referral Agency, which provides a coordinated, whole-of-government approach to the assessment of development applications.

Taking of produced (or associated) water

The P&G Act allows that "the holder of a petroleum tenure may take or interfere with underground water in the area of the tenure if the taking or interference happens during the course of, or results from, the carrying out of another authorised activity for the tenure" (s185(1)). In the case of shale gas and oil development, this will be limited to produced water. Chapter 3 of the Water Act outlines obligations that the tenure holder must follow when exercising these rights, including:

- a requirement to prepare baseline assessment plans (BAPs) that set out how the authority holder will undertake baseline assessments of private water bores

- a requirement to undertake baseline assessments of water bores ahead of any impacts, in accordance with the BAP and Queensland's baseline assessment guidelines (Queensland Department of Environment and Heritage Protection, 2017b)
- a requirement to prepare an underground water impact report (UWIR), which is required to identify the extent of affected aquifers, affected water bores, springs and environmental values in both the short term (3 years) and the long term. The UWIR must include a strategy for groundwater monitoring and a spring impact management strategy. The UWIR process requires public consultation and must be revised every 3 years
- where the UWIR identifies water bores predicted to be affected in the short term (3 years), a requirement to undertake a bore assessment in accordance with guidelines (Queensland Department of Environment and Heritage Protection, 2017b). The purpose of the bore assessment is to determine if the bore is impaired or likely to be impaired as a result of the exercise of underground water rights. Under these obligations, if a water bore has, or is likely to have, an impaired capacity, the authority holder has to 'make good' the impact. The objective of the UWIR and make-good process is to identify potential impacts before they arise, allowing an agreement between the authority holder and the bore owner on make-good measures. There are also provisions for dealing with unforeseen impacts. Where the water bore is impaired, the authority holder must commence make-good negotiations with the affected landholder.

The Water Act also establishes the Office of Groundwater Impact Assessment (OGIA) to oversee the groundwater impacts of the petroleum, gas and mineral resources industry. OGIA is an independent entity responsible for the assessment of cumulative groundwater impacts within prescribed cumulative management areas (CMAs). A CMA may be declared by the Chief Executive of DES under the Water Act when an area contains two or more petroleum tenures and impacts are likely to overlap. To date, only one CMA has been established for the purposes of petroleum and gas – the Surat CMA.

A CMA allows for the independent, cumulative impact assessment of future impacts on a regional basis. OGIA is responsible for preparing UWIRs in a CMA and assigning obligations to each authority holder in the area with regards to establishing monitoring infrastructure, baseline assessments and bore assessments. The Surat CMA was declared in 2011, including the petroleum and gas industry in the Surat and southern Bowen basins. An updated UWIR for the Surat CMA was released by OGIA in September 2016 (Office of Groundwater Impact Assessment, 2016). A revised UWIR will be released for consultation in mid-2019.

EA Conditions relevant to water extraction and disposal

In addition to the provisions under the Water Act for managing impacts on groundwater resources, the EP Act also has requirements that are applicable to minimising environmental harm to groundwater-related environmental values. These aspects must be considered as part of the EA application process. The process described here for regulating extraction of groundwater resources and managing the resulting impacts apply for all petroleum-related activities including CSG, conventional petroleum and shale gas and oil resources. The streamlined model EA conditions for petroleum activities do not cover waste injection (including flowback or produced water), reinjection of treated water, or releases to surface water because of the risk and site-specific nature of some activities (Queensland Department of Environment and Heritage Protection, 2016a). Detailed risk assessments and environmental assessments are required for these activities. s126A of the EP Act has specific requirements for the assessment of impacts on groundwater for activities involving the exercise of underground water rights under the P&G Act.

Flowback water from shale gas and oil activities, which includes a mixture of produced water from the shale formations, return water from stimulation hydraulic fracturing activities and produced water from the shale formations, is considered a waste and therefore regulated under the EP Act and the Waste Act. Disposal of waste must be managed in a way that protects all environmental values, and the EA will contain conditions that the authority holder must comply with to meet this objective. These requirements also apply for reuse of waste water (e.g. for dust suppression), and are discussed further in section 4.5.3.

Commonwealth legislation may also apply if the proposed activities might impact on a Matter of National Environmental Significance (EPBC Act) or the Murray–Darling Basin (*Water Act 2007* (Cwlth)).

4.5.2 Regulation of water-contamination-related impacts

Potential impacts to water values caused by contamination are regulated under the EP Act. The EA for petroleum activities has conditions that the authority holder must comply with to prevent the contamination of surface water. A non-exhaustive list of the components of an EA application that are used to assess the potential impacts arising from contamination of surface water and groundwater and their associated values (land, biodiversity, water, waste management and dams) include:

- a description of the environmental values and sensitivities of shallow groundwater systems, flood plains and springs
- control strategies to prevent land contamination from storage and use of chemicals, corrosive substances and toxic substances, and to prevent contamination from incidental spills, chemical storages and waste storages
- quality of water runoff from areas of activity (considers chemical contaminants as well as turbidity) and requirements for monitoring water released from the site
- reporting requirements for spills
- an assessment of the risks and impacts of managing waste (waste includes flowback and produced water), including the types of and amounts of waste, characterisation of drilling fluids, wastewaters and sewage effluent and the hazardous characteristics of the waste
- waste management practices that consider the types of waste, storage of wastes, transport of waste, monitoring of procedures for dealing with accident spills and other incidents, and disposal, reuse and recycling options
- management of low hazard dams and regulated dams
- a description of project activities that will impact on water. This must consider potential contamination, quantity of water used for the activities and where it will be sourced from, background water quality in the area, identification of downstream users and groundwater users, identification of aquatic ecosystems and groundwater-dependent ecosystems, consideration of cumulative effects of other industries
- a description of the risks and impacts on water resources that may occur due to contamination or changes in water flows, any possible stormwater contamination, and the nature and extent of impacts on aquatic ecosystems, groundwater-dependent ecosystems and other water users
- practices that will be used to manage the impacts on aquatic ecosystems, groundwater-dependent ecosystems and other water users. These practices might include stormwater management, revegetation, processes for clean-up of spills, and the management of these controls
- assessment of risks relating to or caused by hydraulic fracturing, including a description of the chemical compounds used and an environmental hazard assessment of these chemicals and the practices employed to ensure that hydraulic fractures are contained within the target formation.

While this list is not comprehensive, it shows the breadth of water-related aspects that must be addressed during the application and granting of an EA, and the considerations and management that must be followed during the life of a project. In addition, the use of BTEX-containing additives is very tightly regulated (see Section 2.5.2). Commonwealth legislation may also apply to the use of industrial chemicals (additives in hydraulic fracturing for example) through the National Industrial Chemicals Notification and Assessment Scheme (NICNAS).

The transport and handling of hazardous chemicals is regulated under the TO Act and WHS Act. The Transport Operations (Road Use Management – Dangerous Goods) Regulation 2008 sets out the responsibilities of the consignor and prime transport contractors for the transport of dangerous goods by road, and gives effect to the Australian Code for the Transport of Dangerous Goods by Road & Rail (National Transport Commission, 2018) in Queensland. The WHS Act has requirements for the labelling, storage, handling and assessment of risks associated with hazardous chemicals.

While the regulatory framework for the management of impacts related to contamination of surface water and groundwater resources applies to all petroleum activities including shale gas and oil projects, there are additional requirements specific to CSG activities, primarily regarding the management of produced water. These requirements cover aspects such as beneficial reuse, aquifer injection of treated CSG water, the conditions under which an evaporation dam may be used, and management of CSG water, CSG water concentrate, brine, and solid salt residue. Obligations under the Water Act for the monitoring and management of underground water resources are also referred to in the EA.

4.5.3 Regulation of the reuse of produced water

Flowback and produced water are considered to be waste products according to the EP Act. The Waste Act regulates how waste can be used, and allows the Chief Executive of the Queensland Department of Environment and Science to grant approval for beneficial reuse of a waste, such as flowback and produced water. Beneficial reuse could include reuse during shale gas and oil developments, irrigation, construction, dust suppression, and other industrial processes. A general beneficial use approval (BUA) has been granted for produced water as well as a specific beneficial use approval for irrigation using produced water (Queensland Department of Environment and Heritage Protection, 2014a, 2014b). The approvals outline the conditions under which the water may be beneficially reused. The conditions set out water quality parameters and operational aspects that need to be adhered to. Amendments to the Waste Act replaced the BUAs with the end of waste (EOW) framework on 8 November 2016. The current BUAs can continue to be used until the end of their approval periods (16 May 2019 for the general BUA, 24 April 2019 for the irrigation BUA). BUAs will be replaced by EOW codes and EOW approvals.

4.5.4 Regulation of down-hole related impacts

The regulatory framework applicable to down-hole-related impacts incorporates aspects of the EA outlined in Section 4.5.2, which deals with risks relating to hydraulic fracturing operations. A requirement of the model conditions of an EA (Queensland Department of Environment and Heritage Protection, 2016a) is that a risk assessment must be completed for each hydraulic fracturing activities for every well to be stimulated prior to stimulation being carried out. The risk assessment considers things like the composition and hazardous nature of hydraulic fracturing fluids and the processes and procedures that will be used to ensure the hydraulic fractures stay within the target formation. The aquifers surrounding the target formation must be assessed and the potential for contamination must be addressed. The P&G Act also has relevant regulatory requirements that include the need for notification of hydraulic fracturing activities to the Queensland Department of Natural Resources, Mines and Energy and landholders, 10 days before stimulation operations, notification of completion of the activities 10 days after operations have been completed, as well as a detailed final hydraulic fracturing report to be submitted within two months of finishing hydraulic fracturing activities.

Two codes of practice for well construction and abandonment have been prepared by the Queensland Department of Natural Resources, Mines and Energy. There is a code of practice for CSG wells (Queensland Department of Natural Resources and Mines, 2017a) and adherence to this code is required under the P&G Act. A similar code of practice has been prepared for other petroleum wells, including that of shale gas and oil wells (Queensland Department of Natural Resources and Mines, 2016a). The codes of practice have been developed 'to help ensure that all petroleum wells are constructed, maintained and abandoned to a minimum acceptable standard resulting in long term well integrity, containment of petroleum and the protection of aquifers' (Queensland Department of Natural Resources and Mines, 2016a). These codes are being combined into one code of practice, and will be mandatory as of 1 September 2018.

5 Land

5.1 Land impacts summary

The key potential land impacts from shale gas and oil development identified in this review are:

- land disturbance and erosion from surface infrastructure and well pad size and spacing
- land contamination from spills, contaminated drill cuttings, or onsite treatment accidents.

Table 11 provides an overview of the key land impacts, which are those that affect soil, predominantly contamination and erosion from land clearing.

Erosion impacts of shale gas and oil developments are well covered in the published literature, and are likely to be equivalent to those for coal seam gas (CSG) or other industries within the same environments. Land impacts related to land contamination are not widely discussed in published literature. None of the key reviews considered in this study (Broomfield, 2012; The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al.*, 2013; Council of Canadian Academies, 2014; Hawke, 2014) raise landscape contamination as an issue on its own. These impacts are generally discussed in regard to general landscape and biodiversity, downstream effects on water quality, or waste management issues.

In general, the risks to and impacts on land from shale gas and oil developments are similar to those observed for CSG developments. The activities that occur at the surface are very comparable, with the construction of well pads, access tracks, pipelines and other infrastructure.

The key differences are:

- shale gas and oil projects may have fewer well pads (cleared area around the wellhead) as a result of the application of directional drilling and multiple wells per pad
- the well pads will be larger for shale gas and oil to accommodate hydraulic fracturing equipment, larger drill rigs and multi-well drilling
- shale wells will be deeper than CSG wells, creating larger volumes of cuttings
- fewer well pads are likely to mean that there will be fewer access tracks, though they will experience higher volumes of traffic
- shale gas and oil projects will produce liquid hydrocarbons (condensate and oil) that will need to be handled at the surface
- water handling and treatment requirements will be different as shale gas and oil developments will need more water for hydraulic fracturing than CSG, while CSG will have significantly larger volumes of produced water to handle.

These differences are primarily around the overall cumulative effects, and the impacts of an access track or well pad will be very similar whether they are for a CSG or shale gas and oil project. Assessments of the erosion risk are warranted for the specific regions where shale gas and oil developments are likely.

Potential contamination impacts of shale gas and oil developments are related to accidental spills of process chemicals and condensate/oil during development, operations, storage and transport. The scale and intensity of these impacts will be dependent upon many variables including the material, chemical concentrations, quantities, location (e.g. inside a lined bund or not) and control measures employed by industry. These are discussed briefly in regards to land impacts in this chapter, and in more detail as they relate to waste management in Chapter 6.

Table 11 Summary of land impacts of shale and oil gas development

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Impacts related to erosion												
L.1	Addition of access tracks and well pads into landscape.	Disturbance of soil, vegetation and surface water flows and subsequent increase in soil loss, soil loss degrading agricultural productivity and ability to support native flora and fauna, pollution of waterways due to increased sediment loads.	Soil resource for environmental or productive use, downstream water quality.	High (at the scale of the track/well pad. Significant soil disturbance during construction, local factors determine ability of soils to recover and the intensity of impacts on surface water flows, e.g. channel country).	Limited to local (to the site of disturbance and immediate surroundings. Cumulative disturbed area may be significant).	Years to decades (depends on ability of soil to recover).	High. Access tracks and well pads routine component of shale resource development. Higher well density than conventional petroleum, lower density than CSG in most cases.	EA model conditions – specific requirements for protection of land values, to control erosion and sediment and for rehabilitation. EP Act general requirement to avoid harm. Land Access Code, MERCP Act RPI Act.	Medium.	Moderate (intensity and frequency).	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Moderate. Regulation of land clearing for other petroleum activities, significant level of activity for shale resources. Sensitivity to surface flow in some bioregions.
L.2	Addition of gathering and export pipelines into landscape.	Disturbance of soil, vegetation and surface water flows and subsequent increase in soil loss.	Soil resource for environmental or productive use.	Medium to High (significant soil disturbance during construction, local factors determine ability of soils to recover and the intensity of impacts on surface water flows (e.g. channel country).	Limited (to the immediate area disturbed during pipeline construction)	Years to decades (depends on ability of soil to recover).	High. Pipelines routine component of shale resource development.	EA standard conditions for pipelines. EA model conditions – specific requirements for protection of land values, to control erosion and sediment and for rehabilitation. EP Act general requirement to avoid harm. Land Access Code., MERCP Act RPI Act.	Medium. Location dependent.	Moderate (intensity and frequency).	Similar. For shale developments including gas, similar amount of pipeline infrastructure expected.	Moderate. Regulation of land clearing for other petroleum activities, significant level of activity for shale resources. Sensitivity to surface flow in some bioregions.
L.3	Addition of other gas infrastructure (processing plants, compression stations, laydown yards, workers camps).	Localised disturbance of soil, surface water flows and subsequent increase in erosion risk.	Soil loss and changes in surface water flows.	Medium to High, (depends on type of infrastructure, its operating life and level of disturbance).	Limited.	Years to decades (depends on ability of soil to recover).	High. Gas/oil field infrastructure routine component of shale resource development. Amount of infrastructure similar to other petroleum resources.	EA standard conditions for pipelines. EA model conditions – specific requirements for protection of land values, to control erosion and sediment and for rehabilitation. EP Act general requirement to avoid harm. Land Access Code, MERCP Act RPI Act.	Medium.	Moderate (intensity and frequency).	Decreased	Moderate. Regulation of land clearing for other petroleum activities.
L.4	Borrow pits for aggregate for well pads and sand for proppant.	Localised disturbance of soil, surface water flows and subsequent increase in erosion risk.	Soil loss and changes in surface water flows.	Medium, excavation of aggregate and sand may be highly disruptive.	Limited to the site of excavation.	Years.	High, well pads likely to need all weather surface. In very rare circumstances the authority holder may extract proppant sand locally. More likely to source from specialist providers.	If on tenure, gravel and sand extracted solely for shale resource development, then regulated as an ancillary activity. Regulated as for other land disturbance (see impact L.1.).	Medium.	Moderate (intensity and frequency).	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Moderate. Regulation of land clearing for other petroleum activities, significant level of activity for shale resources. Sensitivity to surface flow in some bioregions.
Impacts related to contamination of land												
L.5	Increased rural traffic volumes. See related impact OT.4	Dust both erodes and contaminates land and vegetation at well pads and offsite following transport via wind and deposition.	Environmental quality, flora, fauna, human health, agricultural land.	Low.	Limited (immediate vicinity of access tracks and disturbed sites).	Years.	High. Dirt roads commonly used.	EA model conditions – requirements for protection of land value, requirements to limit erosion includes wind erosion. EP Air Policy limits dust emissions. Environmental Protection Policy Environmental Nuisance applies to dust. EP Act general requirement to avoid harm. Land Access Code, MERCP Act.	Medium.	Low (intensity, scale).	Increased. More truck movements for shale resources.	Low. Regulation air quality (dust) in multiple sectors.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
L.6	Accidental release of process or waste liquids, oil or condensate into the landscape. See related impacts WA.5 to WA.9 and WA.11 to WA.12.	Spillage, overflow, water ingress or leaching, which contaminates land.	Environmental quality, flora, fauna, human health, agricultural land.	Low to medium. Depends on contaminant being released.	Limited (small volumes).	Weeks to years.	Inadvertent.	TO Act (road transport). EA model conditions – storage of chemicals. EA model conditions –to protect land values and monitoring and reporting of spills and leaks. Environmental Protection (Water) Policy WHS Act for safe storage and handling of chemicals. EP Act general requirement to avoid harm.	Medium.	Low (intensity and frequency).	Increased. Frequency of hydraulic fracturing (fluid storage), production of condensate and oil in shale resources likely to be greater than for CSG.	Moderate. Already regulated for other petroleum activities, significant volumes of stored fluids prevalent for shale resources.
L.7	Disposal of drill cuttings.	See impact WE.1 for a description of this impact.										

5.2 Context

The primary geographic setting for shale gas and oil developments in Queensland is in arid to semi-arid regions, where grazing is the primary land use and there are low population densities (e.g. Adavale, Cooper, Eromanga, Galilee and Georgina basins). The basins along the coastal strip are an exception (Maryborough, Bowen and Laura basins), with higher rainfall and a mix of grazing and cropping land uses, and somewhat higher population densities. Impacts on land due to the shale gas and oil life cycle will be significantly influenced by these environments. Cook *et al*. (2013) point out that shale gas production should be considered as a new land use pressure, adding to other land use pressures on the landscape. Impacts on land not only affect the environment, but can also influence the capacity of the land to support other uses.

Land impacts primarily affect soil and include contamination and erosion. The soils in Queensland reflect the geology and climate that they are formed in. Some soils, such as sodium-rich sodosols, are highly erodible when vegetation is removed. Erosion risk in any given area is dependent on a range of factors including rainfall patterns (intensity, frequency, future changes to return periods), soil conditions, topography and ground cover or vegetation. The erosion risk from exposed ground in high rainfall areas will be quite different to those in the arid environments of western Queensland, although arid areas that receive infrequent, extreme events can experience high erosion if ground cover is reduced. Downstream impacts of erosion can include sediment transport and deposition into waterways. Vegetation cover, angle of slope and rainfall intensity are also important factors in determining erosion potential. Potential contamination impacts can also be influenced by the nature of the soil, with some more likely to retain and become damaged.

Development of shale gas and oil projects requires an array of infrastructure that is incorporated across each development area (Cook *et al.*, 2013). Some elements are mostly required during construction (e.g. camps, soil stockpiles), some persist throughout production (e.g. wells, processing facilities) and some may persist after decommissioning (e.g. pipelines, roadways) (see Section 2.2). Well spacing will depend on the characteristics of the shale resource, surface land use and the use of directional drilling techniques. The relative impact of large pipelines used to transport gas from production fields to various markets will depend on the ability to use existing gas transport networks and land availability.

The construction and activities at well pads require the site to be excavated and prepared, and there will be transport of materials to the site. Production will generate waste solids and liquids that will need to be stored and subsequently transported and treated. The key risks to and impacts on the land are likely to be experienced during the production/operational stage of development, and are further described below. During decommissioning of infrastructure (e.g. well pads), reclamation and rehabilitation of land would occur, for which there may be risks related to the methods employed and care is needed to ensure that they are appropriate and do not exacerbate land erosion or contamination.

5.3 Impacts

The potential impacts of the life cycle of shale gas and oil developments primarily relate to soil disturbance during infrastructure construction, particularly in the well field, in addition to contamination of land at well pads from inadvertent spills of process chemicals, oil/condensate and wastewater.

The construction and industrial activities are the same as those used in development of other petroleum resources, including CSG and conventional gas and oil. There are differences in the intensity due to the number of wells drilled for a shale gas or oil project. The extent of potential land impacts are uncertain as the scale and geographic extent of shale gas development likely to occur in Queensland are as yet unknown, and therefore the land area likely to experience impacts from well pads and access roads for shale gas and oil developments is undefined. Well pad size and spacing are the most significant determinants for land impacts (Council of Canadian Academies, 2014; Pepper *et al*., 2018). Section 2.5 includes a discussion on a range of estimates of the area (of the order of 1% to 2% of a petroleum lease area) that may be directly affected by well pads and access roads for a shale gas development. Land impacts are therefore likely to be less than CSG development as the surface density (number of well pads) will be significantly less (possibly as low as one pad per 20 km^2), as discussed previously in Section 3.1.4 and Table 5.

There is a great degree of overlap between potential impacts related to land contamination and risks related to water resources (e.g. contamination due to spills), waste management (handling of regulated waste) and impacts on other land users. This section focuses on direct impacts on land from soil erosion and land contamination.

A summary of land impacts and their materiality are in Table 11, and are further discussed in the following sections.

5.3.1 Land erosion impacts

Land erosion can be caused by the development of surface infrastructure, primarily from land clearing and traffic and equipment movements, which can expose erodible soil and rock and accelerate their mobilisation by wind or rain. The impacts of erosion (impacts L.1 to L.4 in Table 11) include soil loss degrading future agricultural productivity and ability to support native flora and fauna as well as damage to waterways due to increased sediment loads and sedimentation. Vehicle traffic on unsealed roads will generate dust, which can drift and be deposited onto surrounding areas and lead to public nuisance, health and safety hazards, as well as impacting agricultural activities and potentially fauna and flora (impact L.6 in Table 11, discussed further in Section 5.3.2).

Two key reviews outline the components of a shale gas or oil development that are the principal sources of erosion impact, based largely on observations of the industry in the US (Cook *et al*., 2013; Council of Canadian Academies, 2014). This infrastructure development can cause erosion by removal of vegetation cover exposing soil, and changes in surface topography, with subsequent storm water sheet flows or gully erosion across a wide area. Erosion can occur directly on the infrastructure site, or in surrounding areas due to changes in drainage patterns. While based on the North American context, which has very different soil, vegetation and climatic conditions to Queensland, these components will essentially be similar if the same methods are followed. The infrastructure identified includes:

- construction and operation of well pads
- construction of access roads and increased vehicular traffic
- other infrastructure, such as water storage, compressor stations
- construction of pipelines (Cook *et al*., 2013).

The amount of erosion will depend on the size of the area disturbed, soil type, the climatic conditions (wind, temperature, drying potential and rainfall patterns), vegetation and the topography. As well as use of site selection criteria (to avoid slopes and erosive soils), erosion control measures are typically employed by the industry, such as paving of frequently used access roads, placing aggregate on drilling pads to stabilise the soil (aggregate also improves the load bearing capacity of the site to allow heavy vehicle access), and the use of sediment traps to catch suspended sediments in runoff water.

Construction and operations at well pads require a significant volume of traffic and movement of equipment that are likely to result in soil erosion and dust generation. Cook *et al* (2013) estimate that a multi-well pad with six wells may require between 4,000 and 6,300 truck visits across its operating life, with most of those truck movements during drilling and hydraulic fracturing. Dust impacts on amenity, biodiversity and agriculture have also been discussed where relevant in Chapter 7, Chapter 8 and Chapter 11, respectively.

Access road development provides an example of the intensity of the impact that can be caused. Increased erosion risk from road networks arises due the change in surface cover and topography and subsequent water flows across a wide area. Road networks by their very nature intercept water flow paths as they cross catchments. Numerous studies both from Australia and overseas have found that unsealed rural roads covering approximately 1% of catchment area commonly contribute 30% to 50% of the sediment loads into waterways, (Motha *et al.,* 2003, 2004; Mukundan *et al*., 2010; Xu, Ju and Zheng, 2013). Furthermore studies in southern Australia have found that nearly half of the sediment from rural roadways in one catchment came from only 4% of the total road network (Fu, Newham and Field, 2009). These studies highlight the increased risk of erosion from dispersed networks of soil surface disturbance such as unsealed roadways. Studies of erosion risks to shale gas developments in the US have highlighted that unsealed road networks such as these provide a higher erosion risk than the well pads they service (Drohan and Brittingham, 2012).

Pipelines similarly consist of linear elements that extend over large distances across rural landscapes, which can alter soil surface conditions (e.g. topography and vegetation cover), affecting surface water paths or flow velocities and in turn can lead to erosion. Furthermore, the process of pipeline insertion requires more extensive soil disturbance, which can lead to soil subsidence or tunnel erosion under certain soil conditions or inappropriate soil reinstatement (Vacher *et al*., 2014, 2016).

Infrastructure such as well pads, hard stand, stockpile and laydowns are a significant proportion of the overall footprint and involve soil disturbance and land exposure to erosive processes. In many cases, the soil surface will remain modified in these areas, for example, in the case of 'cut and fill' sites created to provide flat working spaces for heavy machinery or storage of materials. Borrow pits may also be excavated to supply aggregate for well pad stabilisation and culverts. These elements will intercept a lower volume of surface water flows than linear elements such as access tracks and pipelines due to their different shape.

The hydraulic fracturing process used for shale gas and oil wells generally requires the use of proppant. Sand is the most commonly used proppant material in shale wells in the US (US US Environmental Protection Agency, 2016a), although manufactured proppants are also used (Council of Canadian Academies, 2014). The amount of sand used is in the order of 100 tonnes per fracture stage (Cook *et al*., 2013; Pepper *et al.,* 2018). A well with 40 fracture stages would therefore need 4,000 tonnes of proppant sand and if 100 shale gas or oil wells were drilled in a year, this would require a total of 400,000 tonnes of sand. To put this in context over 4 million tonnes of sand was mined in Queensland in 2016 (Queensland Department of Natural Resources and Mines, no date c). The sand has to meet specific requirements for size, shape and composition and is likely to be supplied to the industry by specialist suppliers, and the impacts of sand mining will not be directly attributable to shale gas and oil activities. Transport of proppant to the well pad will be a significant component of the overall traffic and will contribute to impacts related to road transport, such as dust.

The areal extent impacted by a shale gas or oil development will influence the scale of the impacts. Section 2.5 includes a discussion of various estimates of the area directly affected by well pads and access roads for a shale gas development, estimated to be of the order of 1% to 2% of a petroleum lease area. The development and operation of a shale gas or oil project may take place over several decades, and access to wells will need to be maintained throughout their operation.

5.3.2 Land contamination impacts

Key pathways to land contamination are through fluid and additive spillage; overflow; water ingress or leaching from well pads during drilling and hydraulic fracturing operations due to operator error; storm water or flood water ingress or; poor construction or failure of a pit liner; oil/condensate spillages and leaks from storage and transport (impact L.6 in Table 11). Land contamination impacts are related to those for surface water and shallow groundwater resource impacts, discussed in Chapter 4.

The contaminants from shale gas and oil activities include the chemicals used in drilling and hydraulic fracturing such as acids, biocides, clay stabilisers, salts, corrosion inhibitors, pH buffers and surfactants (see Section 2.5 for further discussion of chemicals used). Wastewaters (flowback and produced water) at a drilling site also contain a combination of chemical additives from the hydraulic fracturing fluid returning to the surface and chemical constituents originating from the formation water. Shale gas and oil resources will range from those that produce gas with a small volume of liquid (condensate/oil), through to those that are predominately oil with a small volume of gas. After removing any produced water, the oil/condensate will be collected and stored in an above ground tank prior to shipping to a centralised facility (usually via road tanker).

Contamination of the landscape with these chemicals may result in loss of habitat and landscape function (Cook *et al.*, 2013). The scale of the impact will depend on the size and type of contaminating fluid releases into the environment, and the rate of response in control and clean-up measures. The intensity of the impacts will depend on the composition of the fluid released, the concentration of chemicals in the fluid, the amount of fluid released and the impacts to environmental values.

Drill cuttings (impact L.7 in Table 11) can also cause land contamination. They are the solid material left over from the drilling process and consist of cuttings of the formations that have been drilled into as well as solid residues from the drilling mud (clays and salts for example). Drill cuttings are generally benign (e.g. Broomfield, 2012; Cook *et al.*, 2013; Council of Canadian Academies, 2014; New York State Department of Environmental Conservation, 2015a), however, depending on the formations that are drilled, may contain elevated naturally occurring heavy metals, and other possible contaminants. Drill cuttings may be disposed of using a mix-bury-cover method (placing them at least 0.5 m below the final soil surface) at the drill site if benign, or transported offsite to a waste handling facility if they trigger specific waste management regulations. The potential presence of these contaminants will be site and resource specific. Management of waste solids, and specifically contaminated wastes, is further discussed in Chapter 6.

5.4 Comparison with coal seam gas development

In general, the risks to and impacts on land from shale gas and oil extraction are similar to those observed for CSG extraction. The activities that occur at the surface that may cause erosion- or contamination-related impacts are very similar, with the construction of well pads, access tracks, pipelines and other infrastructure. Although the scale of shale gas development likely to occur in Queensland is uncertain, a comparison to the existing development of CSG resources can be indicative.

When considering a single drilling pad, shale gas and oil projects are likely to involve substantially more truck movements than CSG projects. Conversely, shale gas and oil projects are anticipated to have fewer, but larger drilling pads and therefore fewer access tracks compared to CSG projects. These access tracks may need more substantial engineering to accommodate the extra traffic, reduce potential for erosion and limit dust impacts from development. The well pads will be larger for shale gas and oil to accommodate hydraulic fracturing equipment, larger drill rigs and multi-well drilling. Shale wells will be deeper than CSG wells, creating larger volumes of cuttings with implications for handling, treatment and transport.

A study of CSG infrastructure near Chinchilla in southern Queensland (Marinoni and Navarro Garcia, 2015, 2016) found that unsealed well pad access tracks covered approximately 1% of the area for an 11,500 ha area of CSG development, and the total footprint of the operation on the landscape was approximately 8% (see also Table 12). Roadways required for shale gas and oil are likely to be similar in design to those used in CSG and so a similar impact may result for a given length of road. However, the drilling approaches that are used to develop multiple wells from a lower density of well pads will reduce the overall length of roadway relative to that found in CSG development, potentially resulting in a lower erosion impact from shale gas and oil projects.

The local soil and topographic conditions will be a significant determinant of the level of impact. Figure 27 and Figure 28 show erosion-related impacts related to changes to overland water flow caused by CSG access tracks and well pads. These impacts are independent of the purpose of the access track or well pad. Whilst the number of well pads may be reduced for shale gas and oil due to multiple wells being drilled in each well pad, the well pads are likely to be much larger. The overall footprint from access tracks and well pads may be somewhat smaller for shale gas and oil than for CSG, and the erosion impacts from areas of these categories of infrastructure are likely to be similarly reduced.

The risk of soil erosion from CSG and shale gas and oil arises from components of the resource development network including access tracks, pipelines and earth works for infrastructure. Together, linear infrastructure such as access tracks and pipelines accounted for almost half of the total infrastructure footprint of CSG development within the study area described in Table 12. Other distributed infrastructure such as well pad access areas, laydown and stockpile areas, hardstand areas and sand and gravel pits account for one-third of the area but these areas will not intercept as much overland water flow as the linear elements.

Table 12 Footprint of various elements of coal seam gas infrastructure for a portion of the Condabri Tenement operated by Origin Energy near Chinchilla, Queensland

Source: Marinoni & Navarro Garcia 2015

Infrastructure type	Percent of landscape area (%)
Gathering pipelines	1.33
Well pad access areas	1.29
Dams	1.11
Laydown and stockpile areas	1.07
Well access tracks	1.04
Major pipelines	0.94
Camps for workers	0.43
Gas processing facilities	0.23
Sand and Gravel Pits	0.17
Water treatment facilities	0.16
Ponds	0.15
Hardstand areas	0.04
Total	7.96

Shale gas and oil pipeline engineering methods are likely to be similar to CSG projects. Differences in impacts caused by linear infrastructure between the shale gas and oil and CSG industries will be related to differences in the length of pipeline corridor as well as the gathering networks, which are expected to be simpler and less extensive for shale gas and oil projects. The magnitude of impacts from pipelines used to connect production fields to gas markets will depend on the ability to access existing gas transport networks. If use of existing transport networks for shale gas and oil projects is limited, the impacts from these types of pipelines are likely to be similar to CSG projects. Examples of these impacts are shown in Figure 29. Whilst the requirement for gas pipes will be similar, shale gas and oil projects may have a lower requirement for water pipes and so there may be less area required for additional corridor space, stockpiles or laydown areas.

Traffic volumes are likely to be greater for shale gas and oil projects relative to CSG projects (on a per well basis) and this may result in greater fugitive dust. Other contamination impacts are likely to be similar between shale gas and CSG. Contamination of soil through releases of fluids will show similar trends to surface water and shallow groundwater contamination impacts discussed in Chapter 4. In this regard, impacts related to hydraulic fracturing fluids are greater for shale gas and oil projects than for CSG projects, while CSG projects have greater impacts related to produced water.

Drill cuttings from shale gas and oil resource development will typically be much greater than CSG (on a per well basis), as the wells are deeper and thus generate a higher volume of cuttings. The formations that are drilled through to get to the reservoir are similar for both resource types although shale gas and oil resources will drill laterally along shale formations when horizontal drilling is used. These shales tend to have a more complex chemistry than rock types like sandstone and siltstone. In this regard, the potential impacts from drill cuttings from shale gas and oil wells may be greater than for CSG wells, the implications of which are further discussed under waste management in Chapter 6.

As similar road infrastructure will be used, the impacts of an individual access track or well pad will be very similar whether for a CSG project or a shale gas and oil project. The differences in land impacts between shale gas and oil and CSG will be determined by the overall cumulative effects associated with density and scale of shale gas and oil wells relative to CSG. The drilling of multiple wells from well pads will reduce the overall length of road infrastructure relative to that found in CSG development.

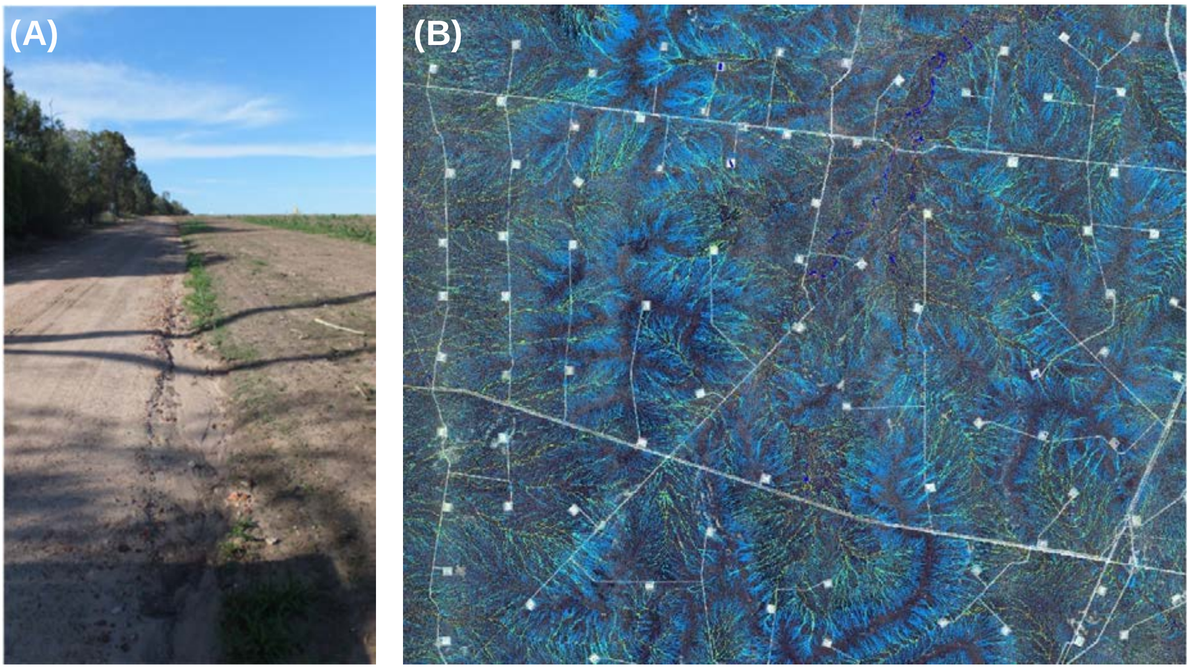


Figure 27 Development of an erosion rill alongside a coal seam gas access track near Chinchilla, Queensland (A), and (B) simulated water flows across an access track network from a 3D reconstruction of the ground surface within a forested section of coal seam gas development near Condamine, Queensland

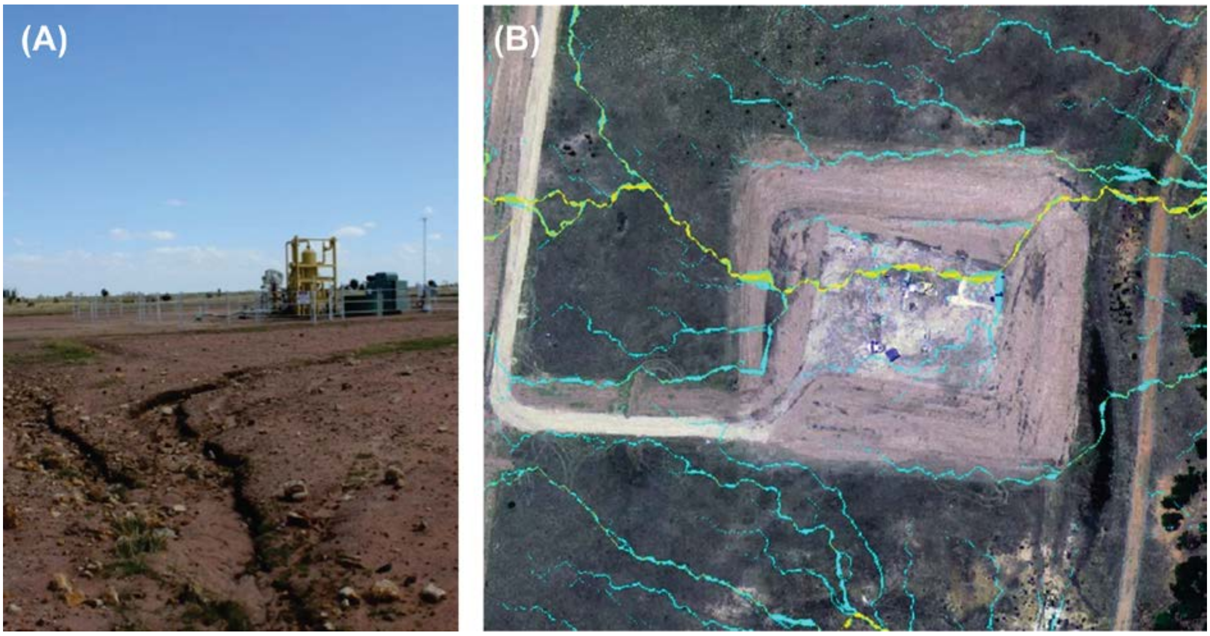


Figure 28 Erosion from a cut and fill well pad site near Chinchilla, Queensland (A), and (B) predicted water flows across the cut and fill well pad site shown left.

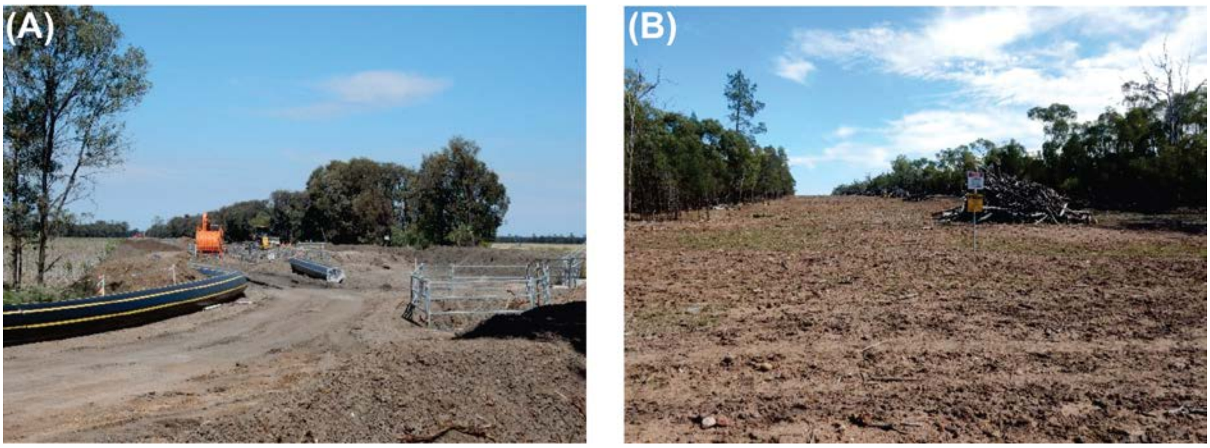


Figure 29 Example of pipeline installation near Chinchilla, Queensland, indicative of the level of soil disturbance (A). Reduced vegetation and soil cover after development of a pipeline corridor near Chinchilla, Queensland (B)

5.5 Relevant regulations

There are two key areas of regulation that apply to impacts on the landscape. The first is under the MERCP Act and related regulations that cover land access for authority holders. Under the MERCP Act the *Land Access Code* has been developed (Queensland Department of Natural Resources and Mines, 2016b). This code sets out best practice for authority holders to communicate with the owners and occupiers of land, public land authorities and public road authorities. It also sets out mandatory conditions concerning their conduct when entering and carrying out authorised activities on private land. For infrastructure that may result in erosion, this code has requirements for the authority holder to minimise impacts by using existing access infrastructure and ensuring any additional infrastructure is developed in a way that minimises its impacts on the landholder. The code does not address environmental impacts directly.

The second area of regulation is under the EP Act. The EP Act sets out general requirements requiring individuals and corporations to minimise environmental harm. The EP Act also has requirements regarding waste material and impacts on water resources. The sediments that are produced by erosion are prescribed water contaminants under the EP Reg, placing constraints on the amount of sediment that can be discharged to waterways whether by erosion or other means. There are other products of shale gas and oil developments that could be considered wastes (e.g. drill cuttings), and some would be considered to be regulated wastes because of their composition, that would have to be managed according to the Waste Act and waste management aspects of the EP Act.

An EA for a project defines requirements and conditions for managing the impacts related to erosion and land contamination. There is significant overlap with the management of impacts related to contamination of surface water and groundwater resources discussed in Section 4.5.2. There are requirements in the EA to consider soil erosion impacts directly as well as the impacts this erosion could have on surface-water-related environmental values. The EA application will also require a management plan for erosion-related impacts, including a stormwater management plan and erosion control measures that will be used at a site. Rehabilitation requirements are also specified. These requirements are contained in the Streamlined Model Conditions for Petroleum Activities (Queensland Department of Environment and Heritage Protection, 2016a). These include conditions:

- requiring the prevention of the release of contaminants to land through the appropriate storage, containment and handling of chemicals and fluids, along with monitoring of storage facilities and the quality of water released from the site of activities, and controls to manage the impacts of incidents including spills, leaks, and stormwater runoff
- requiring the management of topsoil, prevention of erosion and sediment runoff from sites disturbed by petroleum activities, including reference to the International Erosion Control Association Guidelines
- limiting the size of disturbed areas and setting requirements for rehabilitation of disturbed sites
- setting requirements for the backfilling of pipeline trenches and reinstatement of vegetation after the installation of pipelines
- requiring that petroleum activities must not cause environmental nuisance, including from dust, at a sensitive place (for land values, these include protected areas). The EP Air Policy sets limits for dust emissions.

The requirements for rehabilitation of surface disturbances have a general requirement to return disturbed areas to a safe and stable condition, fit for an agreed land use and in a condition that is similar to or better than those that existed before the activities. Consultation with the landholder is important. There are provisions for the transfer of some infrastructure to the landholder, with their agreement. The landholder does not have the right to determine whether rehabilitation has been properly completed; that power lies with the regulator. However, the regulator does require that the landholder be consulted. Authority holders are required to pay financial assurance that covers the full costs of rehabilitation of surface disturbances and this is only refunded once rehabilitation has been completed.

There is also a requirement in the EA process to assess and describe the land-related impacts and the measures that will be taken to minimise the production of hazardous petroleum wastes and land contamination. This may include description of the management of hydrocarbon-contaminated soil and drilling wastes (such as remediation through land application, bioremediation or removal to a place that can lawfully accept the waste).

6 Waste

6.1 Waste impacts summary

This section provides an overview of the potential solid and liquid waste management impacts of shale gas and oil development. Wastewater and solids produced during shale gas and oil development are a potential source of environmental contamination and must be carefully managed (Hawke, 2014). Primary wastes generated from both shale gas and oil consist of:

- drill cuttings from down-hole as the well void is cleared
- drilling fluids
- flowback and produced water (see Section 2.3, Section 2.4 and Table 5).

Other than some discussion on wastewater, most of the major international and national unconventional gas and oil reviews referenced in this report do not mention specific concerns over waste management (Broomfield, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014). In the NT, it was noted that management of wastewater (including drill cuttings) from unconventional gas is similar to many other mining and industrial processes, although treatment of produced water may vary (Hawke 2014). However, the 2018 NT inquiry raised concerns about waste water management and the uncertainty options around options for its treatment and disposal (Pepper *et al*., 2018). Produced water may require some different management practices due to the lower volumes, the specificity of local geology, the potential presence of NORMs and the bringing of these contaminants to the surface where they could have adverse impacts.

The main concern relating to impacts from wastewater is potential for inadvertent spills and associated impacts on land and water during the trucking and transport from site to treatment facilities (see Chapter 4 and Chapter 6). This may be reduced by the use of temporary pipelines where practical (Broomfield, 2012).

The main uncertainty around potential waste impacts is the specific chemical composition of local geology within and above the shale gas and oil resource, and the bearing this will have on the composition of drill cuttings, flowback water and produced water.

Waste generated from shale gas and oil and CSG is likely to be very similar, and is managed under the same legislation and regulatory mechanisms in Queensland, predominantly under the EP Act and the Waste Act.

Table 13 Potential waste impacts from shale gas and oil developments

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
WE.1	Disposal of drill cuttings and other solid waste that may contain contaminants.	Potential contamination risk.	Surface water, shallow groundwater, and soil.	Low to Medium.	Limited, disposal site/well pad scale.	Years to decades	Low. Drill cuttings generally benign, presence of contaminants rare.	EA model conditions – waste management: specific requirements for management of drill cuttings. Waste Act regulates disposal of regulated waste (if certain contaminants present).	Low-Medium. While the composition of drill cuttings in some Qld shale areas is unknown, the process for evaluating and managing this impact is well known.	Low. Existing controls require cuttings to be assessed prior to disposal on site.	Similar (less wells drilled, but will be deeper and many on same well pad).	Low. Regulation of drilling in petroleum, minerals and groundwater sectors.
WE.2	Spills of drilling fluids that may contain contaminants during treatment and disposal. See related impacts WA.5 and WA.6.	Contamination of water and soil, from the potential release of contaminants present in drilling fluids.	Surface water, shallow groundwater, and soil.	Low to Medium, depending on composition of drilling fluid. Non-aqueous fluids have potential for more intense impacts.	Limited, well pad (could also occur at any point along the transport route as well as at receiver facilities if disposed off-site).	Days to weeks. Contamination of shallow groundwater may have impact for years to decades.	Inadvertent.	EA model conditions – waste management: specific requirements for management of drill fluids. EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. Waste Act regulates disposal of regulated waste (if certain contaminants present)	Medium. Uncertainty over composition of drilling fluids.	Low to Moderate. Existing controls on proper disposal of drilling fluids.	Increased (less wells drilled, greater volumes of drilling fluids, more complex drilling fluid chemistry).	Low. Regulation of drilling in petroleum, minerals and groundwater sectors.
WE.3	Spills of hydraulic fracturing fluids, flowback and produced water during treatment and disposal. See related impacts WA.5 to WA.9 and WA.11 to WA.12	Contamination of water and soil, from the potential release of contaminants present in drilling fluids.	Surface water, shallow groundwater, and soil.	Low to medium, depending on composition of fluids.	Limited, well pad (could also occur at any point along the transport route as well as at receiver facilities if disposed off-site).	Days to weeks. Contamination of shallow groundwater may have impact for years to decades.	Inadvertent.	EA model conditions – waste management: specific requirements for management of drill fluids. EA model conditions – requirements to protect water values, including monitoring and reporting of spills and leaks. EA model conditions for dams. Waste Act – general beneficial use / end of waste approvals for associated water.	Medium. Uncertainty over composition of hydraulic fracturing fluids, flowback and produced water.	Low to Moderate. Existing controls on proper disposal of hydraulic fracturing fluids, flowback and produced water.	Decreased (lower volumes of produced water than CSG). However greater volumes of flowback water.	Moderate. Already regulated for other petroleum activities, significant volumes of flowback water for shale resources is unique.
WE.4	Disposal of treated waste water (drilling and hydraulic fracturing fluids, flowback and produced water).	These impacts described and evaluated in WA.11 and IS.3.	Dependant on disposal method – to surface water or groundwater.									

6.2 Context

The management of waste in Queensland is governed by its categorisation into two broad categories: general waste (such as domestic and commercial waste) and regulated waste. Management of most general waste (and municipal wastewater) in Queensland is undertaken by local governments and includes minor industrial or trade waste, which under certain categories is accepted at these treatment and disposal facilities (Queensland Department of Environment and Heritage Protection, 2015a, 2016b). Industrial or trade waste is wastewater from manufacturing and industrial operations such as food processing or metal refining, and in some circumstances where it cannot be accepted at municipal treatment facilities is treated onsite or by transport to private treatment facilities.

Regulated wastes are those (solid or liquid wastes) with known impacts on the environment and human health. There are 71 types of regulated waste in Schedule 7 Part 1 of the EP Reg. Regulated wastes require increasingly sophisticated levels of management depending on their degree of risk to human health and the environment (Queensland Department of Environment and Heritage Protection, 2016b). The storage and treatment of regulated wastes are managed under the EP Reg and generally managed by industrial treatment facilities.

Main options for the disposal of treated wastewaters include:

- Surface discharge to receiving waters
- Deep injection/reinjection into deep aquifers, or
- Beneficial reuse, e.g. for irrigation, dust suppression or other purposes.

The primary driver of the types of treatment and disposal will be the presence and concentration of contaminants such as salts, hydrocarbons (including BTEX), trace metals and NORM as outlined in Section 4.

Waste minimisation and beneficial reuse are also features of the approach to waste management in Queensland (see also Section 4.5.3). A waste can be approved as a resource under Queensland's 'End of Waste Framework' if it meets specific resource criteria under a code or approval, and DES agrees it has a beneficial use (Queensland Department of Environment and Heritage Protection, 2016b). Beneficial reuse of wastewaters is a large and growing area of focus within the petroleum sector, and options could include for example, the use of appropriate quality treated wastewaters for agricultural irrigation or dust suppression.

Primary wastes from shale gas and oil (as for CSG) consist of drill cuttings and drilling fluids as well as hydraulic fracturing flowback water and produced water (see Section 2.3, Section 2.4 and Table 5). Relative quantities of flowback water will be 25% to 75% of the initial injected hydraulic fracturing fluid volume of around 5 to 20 ML per well (Cook *et al* 2013, see also Section 2.4 and Table 5). Quantities of drill cuttings will be of the order of 150 to 200 m^3 for a 3,000 m well interval with a 2,000 m lateral extension drilled using rotary mud drilling methods.

Shale gas and oil operations will also generate a range of other smaller waste streams such as waste surface equipment and infrastructure, sewerage from workers camps etc. These waste streams are expected to be similar to those generated from other industrial activities with the possible exception of the disposal of surface equipment and infrastructure which has the potential of scale build-up containing contaminants. This chapter focuses on the potential waste impacts specific to the development through production phases of shale gas and oil. Decommissioning and end of life waste is out of scope of this report.

6.3 Impacts

Most drill cuttings are usually well below threshold values that would require special isolation techniques for their disposal, are often environmentally benign, and can be buried at the drill site or in landfill (Council of Canadian Academies, 2014). However, as previously described (Section 2.5.1 and Section 5.3.2), drill cuttings can potentially release and combine with contaminants depending on the site-specific and regional geology (impact WE.1, Table 13). Drill cuttings may be disposed of using a mix-bury-cover method at the drill site if benign, or may need to be transported offsite to a waste handling facility if required by specific waste management regulations. Drill cuttings have traditionally been captured onsite in drilling sumps or pits. However, pitless drilling techniques (as used by some CSG operators) may be deployed to provide better management of the drilling fluid and cuttings.

Drilling fluids (impact WE.2, Table 13), as described in Section 2.5, typically consist of water and additives in the form of chemicals used largely to assist in efficient gas extraction operations (including maintaining pH, killing bacteria, controlling fluid consistency, cooling and cleaning drill bits during use, etc.) and include clays, salts and organic polymers (Queensland Department of Environment and Heritage Protection, 2013a). This is similar to CSG, however shale gas and oil developments typically require more complex drilling fluid design to cope with conditions at greater depths (see Section 2.5.1 and Table 8). Typical drilling fluids, particularly commonly used water-based drilling fluids, are considered relatively benign and neither Cook *et al.* (2013) nor the Council of Canadian Academies (2014) raised the loss of drilling fluids as an issue. Inadvertent losses of fluid are likely, but impacts are considered to be of low intensity, small scale and short duration. .

Flowback and produced water (impact WE.3, Table 13) are described in Section 2.3 and Section 4.3.2 including likely composition of flowback waters, which include both hydraulic fracturing fluids and the site-specific chemistry of formation water (e.g. barium, strontium, bromine, metals, organic matter and NORM from the target geology). Wastewater volumes are significantly less for shale gas than for CSG over a project life, and for this reason onsite water treatment facilities (at wellheads, such as for CSG) are unlikely to be required in most cases.

Depending on the size of the overall development, water treatment may be facilitated by the transport of liquid wastes to regional water treatment facilities, or by the construction of a facility to take the aggregated liquid wastes, should a suitable facility not already be available. In Queensland, depending on their composition, these wastes could be regulated wastes that require transport to appropriate facilities for treatment and disposal. If the wastes are not well managed, or if there are inadvertent events such as storage, treatment, or disposal failures, then impacts on the surrounding environment are possible. Ecological, human health and air quality impacts are further described in detail in Chapter 7, Chapter 8 and Chapter 9.

6.4 Comparison with coal seam gas development

Waste management for shale gas and oil and CSG are likely to be very similar, and are managed under the same legislation and regulatory mechanisms in Queensland (Table 2).

Quantities of drilling fluids (Table 5) and drill cuttings for shale gas and oil will be greater per well than for CSG (as per Section 2.4). As previously noted, shale gas and oil wells will be deeper and have longer horizontal sections compared to those for CSG and therefore will require substantially more drilling than CSG wells.

Drill cuttings from shale gas and oil projects are anticipated to have low levels of management required (i.e. mix-bury-cover method) and similar in approach to CSG, unless scheduled waste management regulations are triggered.

Shale gas and oil developments are expected to produce more flowback water than CSG, because hydraulic fracturing operations on shale gas and oil wells are more extensive, with multiple hydraulic fracturing stages in each well, and are conducted on every well rather than just a proportion (around 10% of CSG wells in Queensland have been hydraulically fractured).

Quantities of produced water, are significantly less for shale gas and oil than for CSG over a project life (Cook *et al*., 2013). Compared to CSG, the produced water generated from shale gas and oil is likely to be highly saline, and may contain increased levels of contaminants such as NORMs, heavy metals, and organic compounds (see Section 2.3, Section 2.4 and Table 5). As such, produced shale gas and oil water has the potential to be classified as a regulated waste, therefore may need higher levels of water treatment. Wastewater storage capacity and onsite treatment requirements are likely to be significantly less than for CSG.

6.5 Relevant regulations

The regulation of petroleum activities to prevent or mitigate potential waste-related impacts is primarily through the requirements of the EP Act and the Waste Act. They require transparency in disclosure of the composition of wastes from process sites and have the ability to enforce specific treatment and disposal requirements under the EA process. In Queensland, waste is categorised into general waste or regulated waste, depending on the presence of certain constituents in the waste, as defined in the EP Regs. Wastes designated as regulated wastes require further management of their storage, handling, treatment, disposal and tracking under the EP Act. Handlers of regulated wastes must hold an EA under the EP Act if transporting or receiving the waste, and must also hold the relevant permits for environmentally relevant activities (ERAs) for storage, recycling, treating or disposing of the waste. Additionally, the waste generator, waste transporter and waste receiver all have certain obligations that are set out under the EP Reg.

Wastewater from petroleum activities, including flowback water, produced water and drilling fluids, is considered to be a waste product and must be managed accordingly. Common disposal options for treated wastewater (treated drilling fluids, hydraulic fracturing fluids, flowback and produced water) are evaporation from ponds, discharge to surface water and underground injection. The impact of surface and underground disposal are considered less certain and therefore require a site-specific application for an EA under the EP Act.

Drilling cuttings are also considered waste, and the EP Act requires that if sumps are used to store drill cuttings or drilling fluids, they must only be used for the duration of drilling activities. Cuttings can be disposed of onsite only if they meet acceptable criteria or if ‘environmental harm will not result’ (certified by a suitably qualified third party). In Queensland, similar to Canadian regulations, if oil or synthetic-based fluids are used, or if source rock geology contains scheduled compounds (under the EP Reg), then drill cuttings would be identified as regulated wastes and therefore trackable and subject to more stringent regulations and requirements around their handling, treatment and disposal. Oil and synthetic-based drilling fluids are currently prohibited under the streamlined model EA conditions.

Drilling fluids must be assessed under the EP Reg and the Commonwealth's *National Environment Protection Measure (Assessment of Site Contamination) 1999* (NEPM), and if they are found to pose low risk, then onsite disposal or beneficial use may be approved (as per Section 4.5.3).

Based on both acts, an EA for petroleum activities has requirements and conditions that the authority holder must comply with to prevent potential impacts related to waste. These include:

- requiring that measures must be implemented so that waste is managed in accordance with the waste and resource management hierarchy and the waste and resource management principles in the Waste Act
- authorising uses of flowback and produced water for petroleum activities and setting requirements for the use of produced water
- authorising the disposal of drill cuttings onsite by the mix–bury–cover method if they meet quality criteria
- requirements for the disposal of sewage and other general waste associated with petroleum activities.

Any regulated waste from shale gas and oil activities must be disposed of at a waste handling facility approved for that type of waste.

7 Human health

7.1 Human health impacts summary

Potential human health impacts from shale gas and oil identified in the literature are:

- occupational health impacts from worker exposure to chemicals through chemical handling, industrial accidents or accidental spills
- public health impacts through exposure to process chemicals through water, food or air exposure routes or airborne contaminants such as dust, diesel fumes or VOCs
- noise pollution from industrial activity, such as drilling and traffic from resource development
- psycho-social and amenity impacts on rural communities (positive and negative) from rapid change.

These potential impacts are not dissimilar to those impacts of developments in current Queensland petroleum resource areas, such as CSG.

Internationally, a number of significant reviews discuss the potential human health impacts of unconventional gas development at a country or continental scale including Australia, the UK, Europe, the US and Canada (Lechtenböhmer *et al.*, 2011; Broomfield, 2012; The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al.*, 2013; Council of Canadian Academies, 2014; Department of the Environment and Energy, 2017; Pepper *et al* 2018). These studies have indicated that the greatest risk to human health and the environment is from spills or releases of chemicals during surface activities, such as transport, handling, storage, and the mixing of chemicals. The risks of chemical use are likely to be greatest during surface handling because the chemicals are undiluted and in the largest volumes (Mallants *et al*., 2017b). In a study of compliance-related incidents from gas extraction in Australia, these incidents had a probability of less than one per cent for each phase which is considered exceptionally unlikely (Mallants *et al* 2017b, Mastrandrea *et al*., 2010, and that environmental consequences were reported to be minor (Queensland Department of Environment and Resource Management, 2011).

Within Australia, the CSG Chemicals Assessment comprehensively assessed and characterised risks to human health (discussed further in section 7.3.1) and the environment from handling of chemicals used in CSG extraction (Department of the Environment and Energy, 2017a).

A number of state- or region-specific reviews have also considered health impacts of hydraulic fracturing within Australia, some for shales and some for the shallower CSG, in WA and the NT (shale) and NSW and Queensland (CSG) (Queensland Department of Health, 2013; Hawke, 2014; O'Kane, 2014; WA Department of Health, 2015; Pepper *et al* 2018). Despite the number of major studies published, these studies found that there is sparse information on direct health effects attributable to the unconventional gas and oil industry (Broomfield, 2012; Cook *et al.*, 2013; Council of Canadian Academies, 2014; Pepper *et al* 2018). This is largely due to the relative youth of the industry (less than 40 years) and the challenge of identifying direct causal links between exposure to an environmental factor and adverse health effects, usually through appropriately designed epidemiological studies (O'Kane, 2014; Pepper *et al* 2018).

In the absence of causal links, in Australia environmental and human health risk assessments (EHRAs and HHRAs) are undertaken to assess public health impacts. In these assessments, the elements of the industry are broken down into likely exposure pathways and known contaminant risks, most of which are known or understood from other industries, and extrapolated to potential or likely health impacts (enHealth Council, 2012; O'Kane, 2014; WA Department of Health, 2015; Department of the Environment and Energy, 2017a). The CSG Chemicals Assessment has gone one step further in developing guidance on conducting specific HHRA for the CSG industry (Department of the Environment and Energy, 2017a). From these published reviews and assessments, the potential health impacts of a shale gas industry can be broadly divided into three main categories; direct, indirect and diffuse, which are further discussed in this chapter.

Some reviews specifically exclude impacts similar to existing industries (O'Kane, 2014). This chapter includes a high-level overview of these impacts. It is important to note that for greater certainty, the human health impacts of any future shale gas development would require an analysis of the specific conditions under which each individual development will occur. This would provide a more appropriate local lens through which to understand the impacts that may be experienced and to what degree, and to inform any necessary mitigation measures.

Most human health impacts are regulated under the PH Act, the EP Act and the EP Reg. The EP Act provides the main framework for any form of environmental harm, and applies to any activity having an impact on environmental values, which extend to clean air, land and drinking water. It applies to regulation of noise, dust and public amenity (nuisance) impacts in Queensland. Additional and specific regulation applies for occupational health and safety, drinking water, and the management of hazardous substances (NICNAS).

Table 14 provides a summary of the potential impacts, which are discussed in more detail in this chapter.

Table 14 Summary of potential human health impacts of shale gas and oil developments

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Occupational health impacts												
H.1	Occupational chemical handling.	Direct exposure of workers to toxic substances during occupational chemical handling.	Human health.	High. Chronic health issues.	Individual to multiple workers.	Weeks to years.	Inadvertent to low. Some level of exposure always present.	WHS Act P&G Act EP Act (limiting release of hazardous substances). RS Act	Low.	High (because of potential to cause significant harm to workers)	Similar.	Low. Regulation of workplace health and safety conducted across multiple sectors, including specific legislation for petroleum and gas activities.
H.2	Industrial accidents.	Worker mortality or injury due to industrial accidents.	Human health.	High. Acute injury or death.	Individual or multiple workers.	Hours to days.	Inadvertent.	WHS Act P&G Act EP Act (limiting release of hazardous substances). RS Act	Low.	High (because of potential to cause significant harm to workers)	Similar.	Low. Regulation of workplace health and safety conducted across multiple sectors, including specific legislation for petroleum and gas activities.
Public health impacts												
H.3	Accidental surface spills of chemicals during handling or transport. See related impact WA.3.	Direct exposure of members of the public to toxic or harmful chemicals and liquid hydrocarbons (condensate/oil).	Human health.	High. Potential for acute injury or death.	Limited. Scale of spill.	Hours to days.	Inadvertent	TO Act (road transport). EA model conditions – storage of chemicals. EA model conditions –to protect water, land and biodiversity values, and monitoring and reporting of spills and leaks. Environmental Protection (Water) Policy WHS Act for safe storage and handling of chemicals. EP Act general requirement to avoid harm.	Medium. Exposure paths and concentrations not well understood.	Medium to high (because of potential to cause significant harm)	Increased. Shale resources likely to produce liquid hydrocarbons that will require transport. Greater volume of hydraulic fracturing chemicals transported.	Low. Regulation of transport and handling of hazardous chemicals across multiple sectors.
H.4	Air pollution from burning diesel, evaporation of process water, ozone, dust, produced hydrocarbons and other gasses. See related impacts AQ.4 and AQ.5	Public exposed to air pollution, dust, may cause respiratory problems.	Human health.	Low. Exposure to low concentrations of pollutants.	Limited to local.	Days to years.	Low. Some change to air quality inevitable, however intensity will depend on proximity to source. Public exposure rare.	EA model conditions – storage of chemicals. EA model conditions – requirements to protect air values. Environmental Protection (Air) Policy EP Act general requirement to avoid harm. National Environment Protection (Ambient Air Quality) Measure 1998 (Cwlth)	Medium. Exposure paths and concentrations not well understood.	Low (limited exposure, particularly in rural areas)	Increased. Shale resources likely to produce other hydrocarbons in addition to methane, may include PAH's, VOC's, BTEX. H_2S may also be produced.	Low. Regulation of air pollution across multiple sectors.
H.5	Water pollution from accidental surface spills. See related impact WA.3 to WA.7	Contamination of drinking water or food through surface water or shallow groundwater from spilled hydraulic fracturing chemicals and liquid hydrocarbons (condensate/oil).	Human health.	High. Accidental spills should be rare, but where they occur the impact would be concentrated.	Limited to local, scale of affected water resource.	Hours to years.	Inadvertent.	TO Act (road transport). EA model conditions – storage of chemicals. EA model conditions –to protect water, land and biodiversity values, and monitoring and reporting of spills and leaks. Environmental Protection (Water) Policy WHS Act for safe storage and handling of chemicals. EP Act general requirement to avoid harm.	Low.	Medium (because potential impact on drinking water resource)	Increased. Shale resources likely to produce liquid hydrocarbons that will require transport. Greater volume of hydraulic fracturing chemicals transported.	Low. Regulation of transport and handling of hazardous chemicals across multiple sectors.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
H.6	Water pollution from migration of hydraulic fracturing chemicals into shallow groundwater. See related impacts WA.15 to WA.18	Contamination of groundwater used as a drinking water source.	Human health.	Low. Contaminant concentrations for an individual well unlikely to cause contamination, cumulative impacts may be greater.	Limited to local to regional, scale of affected water resource.	Years to decades.	Inadvertent. Low likelihood of connectivity between target depths and groundwater used as a drinking water source.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EA model conditions – requirements to protect water values. Includes offset distances from water sources such as bores. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	Low	Low (low intensity, frequency)	Increased, as number of hydraulically fractured wells in shale resources significantly greater than for CSG.	Moderate. Already regulated for other petroleum activities, high prevalence of hydraulic fracturing for shale resources.
H.7	Water pollution from migration of hydraulic fracturing fluids via offset wells. See related impacts WA.16 to WA.18.	Contamination of groundwater used as a drinking water source.	Human health.	Low. Contaminant concentrations for an individual well unlikely to cause contamination, cumulative impacts may be greater.	Limited to local to regional, scale of affected water resource.	Years to decades.	Inadvertent. Requires offset wells with poor integrity or that have been improperly abandoned. Not likely to be a significant issue in Queensland.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EA model conditions – requirements to protect water values. Includes offset distances from water sources such as bores. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	Low.	Low (low intensity, frequency).	Similar, as number of hydraulically fractured wells in shale resources significantly greater than for CSG, although offset wells less likely.	Moderate. Already regulated for other petroleum activities, high prevalence of hydraulic fracturing for shale resources.
H.8	Land contamination from waste rock cuttings or sludge from wastewater ponds. See related impact WE.1.	Contamination of land that may be used for food production.	Human health.	Medium (in waste rock or wastewater disposal areas).	Limited, disposal site/well pad scale.	Years to decades.	Inadvertent to low. Drill cuttings generally benign, presence of contaminants rare.	EA model conditions – waste management: specific requirements for management of drill cuttings. EA model conditions – requirements to protect land values. Waste Act regulates disposal of regulated waste (if certain contaminants present).	Medium.	Low (small scale, limited frequency).	Similar (less wells drilled, but will be deeper and many on same well pad).	Low. Regulation of drilling in petroleum, minerals and groundwater sectors.
H.9	Use of some or all of large trucks, heavy equipment, generators and gas flaring.	Noise pollution, amenity impacts.	Human health.	Moderate in close proximity to transport routes or well pads.	Local (well pad) to regional (transport routes).	Years.	High. Exposure will depend on population densities in where shale activities take place.	EA model conditions = specific requirements to protect acoustic values. Environmental Protection (Noise) Policy Land Access Code. RPI Act. TO Act.	Low.	Moderate (very location specific, dependent on proximity of shale activities to population centres).	Similar. Scale of development similar, number of truck movements per well likely to be greater for shale resources.	Moderate. Already regulated for other sectors, high volume of traffic/activity for shale resources.
H.10	Community change from rapid industrial development.	Psycho-social impacts on local communities (loss of control, threatens sense of place). Potential positive impacts not assessed.	Human health.	High where industry develops quickly or within a concentrated area.	Local to regional.	Years.	High.	Considered in Social Impact Statements as part of EIS process.	Low (evidence from CSG development).	Moderate (intensity and frequency).	Similar. Location dependent, less likely to be an issue in remote parts of Queensland.	Moderate. Has been an issue for other resource developments.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
H.11	Shale gas and oil development and associated activities in general.	Psycho-social impacts on local communities caused by fear of the unknown and public concerns related to hydraulic fracturing, induced seismicity, water use, water contamination, well integrity.	Human health.	High where industry develops quickly with limited understanding in the community.	Local to regional.	Years.	High.	Not directly addressed.	Medium.	Low to moderate (on human health).	Similar. Location dependent, less likely to be an issue in remote parts of Queensland	Moderate. Has been a significant issue for other resource developments.
H.12	Industrial development in previously exclusively agricultural environments.	Change in amenity value resulting in reduction in enjoyment of lifestyle, self-esteem and wellbeing.	Human health.	High where industry develops quickly in a concentrated (previously rural) area.	Local to regional.	Years.	High.	Considered in Social Impact Statements as part of EIS process.	Low (evidence from CSG development).	Moderate (intensity and frequency).	Similar. Location dependent, less likely to be an issue in remote parts of Queensland.	Moderate. Has been an issue for other resource developments.
H.13	Increased volume of traffic	Traffic accidents.	Human health.	High. Acute injury or death.	Local to regional.	Years.	Inadvertent.	Considered in Social Impact Statements as part of EIS process. TO Act.	Low.	High (because of potential to cause significant harm).	Similar. Location dependent, less likely to be an issue in remote parts of Queensland.	Moderate. High volume of traffic/activity for shale resources.
H.14	Increased volume of traffic causing damage to roads.	Reduced access to health services. Potential positive impacts from improvements to infrastructure not assessed.	Human health	Medium.	Limited to local.	Days to weeks. Damaged roads likely to be repaired.	Inadvertent to low.	Considered in Social Impact Statements as part of EIS process. TO Act.	Medium (location specific).	Medium to high (because of potential to cause significant harm).	Similar. Location dependent, more likely to be an issue in remote parts of Queensland with dirt roads.	Moderate. High volume of traffic/activity for shale resources.

7.2 Context

Part of the difficulty in obtaining a definitive understanding of potential health impacts is that the occurrence and significance of impacts of shale gas and oil developments on physiological human health will depend on many variables specific to a resource development. Variables such as population density, proximity of food and water sources to contaminants, vulnerable groups in the population, existing sources of pollution, regional geology and hydrogeology, legal/regulatory frameworks and their degree of appropriate monitoring and enforcement, workforce training and management of occupational risks, and the frequency and intensity of development (Cook *et al.*, 2013; Council of Canadian Academies, 2014; WA Department of Health, 2015; Department of the Environment and Energy, 2017a, Pepper *et al* 2018), are all important factors in determining potential health impacts.

Primary concerns of both the public and health agencies regarding potential human health impacts of shale gas development focus on five main areas. These largely correlate to the components of shale gas and oil developments which are the least similar to other industries:

- toxicity of chemicals used (e.g. fracturing fluids) or generated in the process (e.g. flowback and produced water)
- likelihood and consequences of human exposure (risk assessments, exposure pathways)
- appropriate treatment and disposal of chemicals
- appropriate approvals, monitoring, regulatory, control and response measures in place
- cumulative impacts over long timescales (beyond the scope of this review).

Most major reviews of shale gas and related hydraulic fracturing suggest that the potential risks to human health can be mitigated. The CSG Chemicals Assessment further found that there is considerable coverage in the literature on such mitigating measures for potential human health impacts, and the majority of major reviews call for:

- robust regulatory oversight and breach enforcement throughout project life (Cook *et al*., 2013; Hawke, 2014; Pepper *et al*., 2018)
- transparency of process chemicals used (Cook *et al*., 2013), toxicity assessments for complex mixtures (Department of the Environment and Energy, 2017a) and some call for bans on the use of certain toxic substances (Lechtenböhmer *et al*., 2011)
- the implementation of high-quality tailored baseline and ongoing monitoring in development areas including flexibility in their design to allow for adaptation to advances in technology (Cook *et al*., 2013; Council of Canadian Academies, 2014; O'Kane, 2014; Pepper *et al*., 2018)
- application of best-practice engineering and risk assessment measures by industry throughout project life cycle, including site-specific operational risk management (O'Kane, 2014; Department of the Environment and Energy, 2017a; Pepper *et al*., 2018;)
- transparent public engagement frameworks, including with the people living in affected areas and independent experts (Cook *et al*., 2013; Council of Canadian Academies, 2014; Pepper *et al*., 2018)

- appropriate emergency response procedures (O'Kane, 2014)
- comprehensive decommissioning and abandonment plans (Cook *et al*., 2013)
- further research into impacts as the industry develops (Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014; O'Kane, 2014; Department of the Environment and Energy, 2017a; Pepper *et al*., 2018;).

With these controls in mind, shale gas and oil developments are not anticipated to result in significant impacts on human health if risks are managed within these frameworks (Broomfield, 2012; Cook *et al.*, 2013; Council of Canadian Academies, 2014; Hawke, 2014; Department of the Environment and Energy, 2017a; Pepper *et al*., 2018).

7.3 Impacts

This section first discusses the potential materials that are hazardous to health involved in shale gas and oil, and then the potential human health impacts are divided into three main categories in the discussion following:

- **occupational exposure** from direct exposure to industrial processes (e.g. chemical use, machinery, spills, including occupational exposure for those working in the industry and accidental exposure to the public) (impact H.1 and impact H.2 in Table 14)
- **public health impacts** from exposure to contaminated air, land or water from unintended release of industrial by-products, or ingestion of contaminated food (impact H.3 to impact H.8 in Table 14)
- **community impacts** from proximity to industry operations, including psycho-social, amenity and quality of life impacts (impact H.9 to impact H.14 in Table 14).

Table 14 provides a summary of the potential impacts for each of these three categories. They are discussed in more detail in the following sections.

7.3.1 Potential hazardous materials

Greatest health concerns amongst the public arise from the perceived lack of transparency around potentially hazardous chemicals used in the composition of hydraulic fracturing fluids (Council of Canadian Academies, 2014). The usual chemistry of hydraulic fracturing fluids is discussed in Section 2.5.2, Figure 19 and Table 8. The additives used in fracturing fluids, whilst generically similar in their combination of functional areas, differ between companies and are based on site conditions of the specific resource, local geology and company experience, and which chemicals are approved for use in the relevant jurisdiction. Their recipes may represent a competitive advantage and some companies in other jurisdictions have been reluctant to reveal all aspects of their formulae. This has fed public distrust and many jurisdictions have taken steps to either partially or fully require disclosure to regulatory agencies to ensure appropriate controls are in place.

In Australia the Commonwealth's *Industrial Chemicals (Notification and Assessment) Act 1989* (IC Act) applies to hydraulic fracturing fluids and requires the notification and assessment of the use of industrial chemicals within Australia, regulated by the Australian Government Department of Health (through NICNAS). Whilst an important step, it is considered that mandatory disclosure of the composition of process fluids and flowback waters is necessary to provide transparency, however, it is insufficient in the assessment of the risks associated with hydraulic fracturing (Council of Canadian Academies, 2014). CSIRO recently collaborated on a major review of hydraulic fracturing chemicals used in CSG under NICNAS, released in 2017 (Department of the Environment and Energy, 2017a).

The CSG Chemicals Assessment provides world leading practice advice on approaches for human (and environmental) risk assessments for the coal and CSG industries (see also section 4.4.2) (Department of the Environment and Energy, 2017b). In particular, the new risk assessment guidance specifies that naturally occurring geogenic chemicals mobilised by drilling or hydraulic fracturing, and found in drilling fluids and drilling muds, flowback and produced water, brines, and treated water, should be included as an essential component of any risk assessment.

The CSG Chemicals Assessment addressed health risks to both onsite workers, where there is a potential for higher exposures, and to the general public, when exposed through offsite contamination of water used for drinking or recreation. Environmental risk assessments were also carried out. The Assessment found that the greatest pre-mitigation risk of harm to public health or the environment was in the event of a large-scale transport spill. The main pre-mitigation risks to CSG workers is from industrial accidents and handling chemicals while maintaining equipment or mixing and blending, mainly because they work with chemicals in more concentrated forms. Even in this case, applying the required safety and handling precautions such as wearing protective equipment and promptly notifying and cleaning up spills, reduces the risk significantly (Department of the Environment and Energy, 2017a). The majority of chemicals were found to be unlikely to cause harm to the environment when used in CSG extraction, even if they were to spill or leak in high volumes. It is in the event of a transport spill or where untreated waste water containing chemicals is reused for irrigation or dust suppression, that certain chemicals have the potential to cause harm to the environment (Department of the Environment and Energy, 2017a).

For shale gas developments, of greater concern in recent years are those substances extracted from shale gas deposits at depth and brought back to the surface through flowback and produced waters (Pepper *et al*., 2018; Department of the Environment and Energy, 2017). Although the amount of wastewater generated from shale gas and oil will be an order of magnitude less than from CSG, it is likely to be highly saline, and may contain 'geogenic' chemicals such as heavy metals, NORM and organic compounds (such as BTEX) and other hydrocarbons (see Section 2.3, Section 2.4, Section 6.4 and Table 5). During hydraulic fracturing, the fluids mix with formation material at depth, resulting in a large volume of liquid waste containing these substances that must be managed (Queensland Department of Environment and Heritage Protection, 2013a). Testing and disclosure of these geogenic substances will need to be a key focus for informing environmental approvals processes.

HHRAs are useful in this context and work to identify risk and mitigation strategies ahead of developments, rather than awaiting results of epidemiological studies once a development is in place (enHealth Council, 2012). Some reviews of human health impacts also call for a broader understanding of the '*concentration, mobility, persistence and bio-accumulation of the arising chemistry*', which '*represent a major gap in understanding of the potential environmental and human health impacts of hydraulic fracturing, and their potential mitigation measures*' (Council of Canadian Academies, 2014). Included in the CSG Chemicals Assessment are recommendations for conducting direct toxicity assessments of complex mixtures, such as fracking fluids and produced waters, where use of toxicity values in HHRAs for individual chemicals may either overestimate or underestimate the toxicity of the mixture. Where these are not yet known, this will require a greater investment in research in resource development areas to fully ascertain cumulative and flow-through effects. The approaches outlined in the CSG Chemicals Assessments' guidance documents could be readily adapted for any development of any onshore shale gas industry (Department of the Environment and Energy, 2017b).

Other potentially hazardous materials associated with shale gas development include airborne chemicals or contaminants such as VOC gases and vapours, diesel fumes associated with transport and drilling equipment and airborne dust from site development activities (Council of Canadian Academies, 2014; Pepper *et al*., 2018). These are discussed further in Section 7.3.3.

7.3.2 Occupational impacts

Only minor treatment is given to the occupational impacts of unconventional gas in the major review literature, in part because the impacts are similar to other industries and are already managed through relevant state and federal occupational health and safety legislation and appropriate industry engineering and risk management practices (O'Kane, 2014; Department of the Environment and Energy, 2017; Pepper *et al*., 2018).). For this reason, some additional studies were drawn upon from the US shale gas industry experience, given their longer history of unconventional gas development (Adgate, Goldstein and Mckenzie, 2014). The potential impacts include:

- occupational exposure of workers to hazardous materials – either through normal chemical handling of process chemicals, or inadvertent events such as accidental spills of chemicals and industrial by-products (Lechtenböhmer *et al.*, 2011; Department of the Environment and Energy, 2017a)
- increased risk of industrial accidents – injuries to workers from operating heavy machinery, plant and equipment (Adgate, Goldstein and Mckenzie, 2014)
- transport accidents – from the higher volumes of heavy vehicle traffic likely to be experienced in shale gas developments (Adgate, Goldstein and Mckenzie, 2014; O'Kane, 2014).

The main pre-mitigation risks to unconventional gas workers is from industrial accidents and handling chemicals while maintaining equipment or mixing and blending, mainly because they work with chemicals in more concentrated forms. Even in this case, applying the required safety and handling precautions such as wearing protective equipment and promptly notifying and cleaning up spills, reduces the risk significantly (Department of the Environment and Energy, 2017a). These impacts are managed in Queensland within existing petroleum, mining and industrial activities, and would not be expected to be specific to or any different for shale gas and oil developments.

7.3.3 Public health impacts

As with any transport of chemicals, there is some potential for direct exposure of workers or the public to industrial chemicals through inadvertent events such as chemical spills (e.g. from transport accidents), or onsite spills where sites are proximal to settlements. Onsite spills close to settlements are, however, unlikely in Queensland considering the very low population densities in the most prospective shale gas resource areas and the likelihood of industrial process sites being located at significant distances from the public under existing legislative approval requirements (i.e. through the RPI Act). The RPI Act identifies and protects areas of Queensland that are of regional interest and resolves potential land use conflicts. The Act protects living areas in regional communities, high-quality agricultural areas from dislocation, strategic cropping land, and regionally important environmental areas. In Queensland, the TO Act manages road use impacts and requires companies to implement traffic management plans.

Transport accidents are a possible additional impact, due to likely increased traffic volumes with industry development, and in the UK were considered to be of high concern (Broomfield, 2012). They were also raised as a potential impact in the NT HF Inquiry (Pepper *et al*., 2018). This impact could be expected to occur wherever there is an increase in traffic and is not shale gas and oil specific.

International studies also found that the greatest risk to human health and the environment is from releases of chemicals during surface activities such as transport, handling and storage of chemicals, because the chemicals and undiluted and in the largest volumes (The Royal Society and Royal Academy of Engineering, 2012; Vidic *et al*., 2013; Mallants *et al*., 2017b). The CSG Chemicals Assessment found that the greatest pre-mitigation risk of harm to public health or the environment was in the event of a large-scale transport spill. Applying the required safety and handling precautions such as promptly notifying and cleaning up spills, reduces the risk significantly (Department of the Environment and Energy, 2017).

7.3.3.1 Air

Shale gas development may adversely affect local water and air quality (e.g. hydrocarbons, volatile organic compounds (VOCs) such as benzene) (Council of Canadian Academies, 2014; Pepper *et al* 2018). There is growing evidence to suggest that greenhouse emissions may be lower when compared to other fossil fuel energy sources, discussed further in Section 9.3.1. The following discussion focuses on the potential air quality impacts on human health.

Air quality is influenced by emissions from human activities such as transport, industrial, rural and domestic activities. The main human sources of air emissions in Queensland are transport and industrial activities. Air quality can also be influenced by natural factors such as bushfire, wind, rainfall and dust storms. Air quality impacts from shale gas and oil developments will largely arise when a development is in close proximity of settlements due to emissions from diesel generators and compressors (although such equipment may already exist in the communities), in addition to increased volumes of traffic to and from process sites (Broomfield, 2012; Adgate, Goldstein and Mckenzie, 2014; O'Kane, 2014). Key concerns relate to BTEX, sulphur, carbon and nitrogen oxides, VOCs, hydrogen sulphides, ozone, particulates and radiation (Broomfield, 2012; Cook *et al.*, 2013; Adgate, Goldstein and Mckenzie, 2014; Pepper *et al*., 2018). Shale gas and oil resources will also produce condensate/oil, and may contain VOCs, PAHs and BTEX.

Diesel engines are a well-known and understood feature of industrial and particularly rural landscapes. It is anticipated that the siting of well pads, with their intensive plant and equipment requirements, are unlikely to be located proximal to settlements in Queensland. Although the requirements for shale gas and oil developments at a single well pad for plant, equipment and processing facilities will be more intensive than CSG, the well spacing is an order of magnitude greater as is the opportunity to site well pads further from settlements due to the ability to drill a well both vertically and horizontally (also discussed in Section 2.5.1). The expected concentration of diesel engines in a given region during development of a single well pad are therefore anticipated to be similar to those already experienced with CSG.

The Council of Canadian Academies (2014) notes a range of possible air pollutants associated with shale gas and oil developments and their potential negative health effects (Table 15). Many of these identified acute effects are relevant only where there was exposure to high concentrations of these contaminants. There is limited evidence that the concentrations to achieve these health effects have been realised in shale gas and oil developments.

Ozone levels were considered in the UK to be of material impact on respiratory health (Broomfield 2012). Most of these airborne substances are related to vehicular traffic, and so the impacts of shale gas developments would need to be placed in context with emissions from other vehicles and the risks posed by human exposure to emissions from vehicular traffic as a result of living in densely populated cities.

Air quality impacts have also been discussed in section 9.3.2.

Table 15 Air pollutants associated with shale gas and oil developments and their potential acute health effects if there was exposure to high concentrations

Substance	Potential acute health effects
Particulate matter (PM).	Non-fatal heart attacks. Irregular heartbeat. Aggravated asthma. Reduced lung function. Increased respiratory symptoms (e.g., coughing, difficulty breathing). Premature death in people with heart or lung disease.
Nitrogen oxides (NO_x).	Irritated respiratory system. Aggravated asthma, bronchitis, or existing heart disease.
Carbon monoxide (CO).	Exacerbation of cardiovascular disease. Behavioural impairment. Reduced birth weight. Increased daily mortality rate.
Volatile organic compounds (VOCs) (e.g. BTEX).	Carcinogen (some VOCs). Leukemia and other blood disorders (benzene) birth defects (some VOCs). Eye, nose, and throat irritation (some VOCs). Adverse nervous systems effects.
Methane (CH_4)	Asphyxiation in confined spaces.
Ground level ozone (O_3) (smog)	Aggravated asthma or bronchitis. Permanent lung damage.

Source: Council of Canadian Academies 2014

7.3.3.2 Drinking water

In Queensland, most of the population is served by approximately 180 public water supplies, which are drawn from a variety of sources including dams, rivers and groundwater, and in some highly populated areas, desalination plants (Queensland Department of Energy and Water Supply, 2016). In most rural and regional areas, the public water supplies are provided by local councils (Queensland Department of Energy and Water Supply, 2016). Potential impacts of shale gas development on water in the environment are discussed in detail in Chapter 4. For a water supply to be used for drinking water purposes it is regulated and there is a great degree of scrutiny over its composition and management. This section discusses the potential impacts of shale gas and oil developments on drinking water in Queensland and how impacts from similar industries are currently managed.

In the major reviews of shale gas and oil potential impacts, there is limited information on drinking water impacts (Cook *et al.*, 2013; Council of Canadian Academies, 2014; Hawke, 2014). As with the broader human health impacts, this is largely in part due to the difficulty of tracking and linking shale gas impacts to drinking water due to lack of baseline data and the limitations of epidemiological studies (O'Kane, 2014; New York State Department of Public Health, 2015). Private drinking water wells in both Australia and Canada have lower levels of monitoring and oversight than town supplies. In Canada, although attempts were made to review private wells in shale gas resource areas, there were difficulties in assigning any direct impacts on drinking water (Council of Canadian Academies, 2014).

The US Environmental Protection Authority (EPA) has recently completed a major assessment of hydraulic fracturing and its potential impact on drinking water resources (US Environmental Protection Agency, 2016a). This assessment provides a comprehensive assessment of these impacts. This study identified pathways for contamination of drinking water supplies, the toxicity of chemicals used in hydraulic fracturing, treatment options for wastewater from shale gas and oil activities, as well as identifying gaps and uncertainties about impacts on drinking water. The study found that limited data are available on direct impacts from hydraulic fracturing (from surface spills, hydraulic fracturing, management of wastewater) on the frequency and severity of impacts on drinking water. They conclude that the impacts will depend on the toxicity of the chemicals used, the size release of contaminants and the volume of water that is contaminated.

As previously stated, the main mechanisms for potential contamination of drinking water in shale gas and oil developments are from surface spills of process chemicals or improper waste management of contaminated drill cuttings and fluids. These vectors could expose rivers or dams to contamination, or lead to the underground communication of residual hydraulic fracturing fluids through induced or natural fractures into current or future groundwater sources used for drinking water (New York City Department of Environmental Protection, 2009; Cook *et al.*, 2013; Council of Canadian Academies, 2014; Hawke, 2014; US Environmental Protection Agency, 2016a; Pepper *et al*., 2018). It is often stated that the physical distance and permeability differences between target shale horizons (1000 to 4000 m below surface, low permeability) and usually very shallow drinking water sources (95% of bores in Australia are less than 200 m below surface) prohibit the likelihood of connection between the two, however, some early evidence of this potential connectivity exists (Cook *et al.*, 2013). Also in Queensland, groundwater resources are generally much deeper, particularly in the Great Artesian Basin (GAB) (Chapter 5), and as such, greater understanding of fracture and fault connection and risk assessment and management in this jurisdiction will be prudent. In New York, a hydraulic fracturing public health review found potential for underground migration of hydraulic fracturing chemicals to have been associated with faulty well construction (New York State Department of Public Health, 2015).

The WA Department of Health conducted a specific human health risk assessment in 2015, which assessed the potential of hydraulic fracturing processes to affect human health through contamination of drinking water sources (WA Department of Health, 2015). The risk assessment examined toxicity of commonly used hydraulic fracturing fluids, potential exposure pathways to drinking water sources, and the likelihood and consequences of contamination events. The assessment found that the likelihood of any contamination event occurring would depend on the failure of licence holders to follow industry best-practice design, construction, maintenance and closure, or to fully implement effective management plans including monitoring impacts of any releases above natural background levels (WA Department of Health, 2015). The WA Department of

Health concluded that under the right conditions, hydraulic fracturing could successfully be undertaken in WA shale gas reserves without compromising drinking water sources.

Like other potential contaminant impacts from shale gas and oil, drinking water impacts will depend not only on the chemicals used but their fate, transport and accumulation in current and potential future drinking water sources. Surface spills and waste management can be managed with operational controls and incident response, and their impacts are largely understood. Impacts of both areas can be further mitigated through the reduced use of types and quantities of chemicals potentially harmful to human health. Additionally, use of the HHRA process as defined in the CSG Chemicals Assessment will be important for assessing human health risks to drinking water in specific locations where the industry may develop (Department of the Environment and Energy 2017a; Pepper *et al*., 2018).

Whilst public water supply schemes are generally well managed and monitored by regulatory agencies, private drinking water supplies within Queensland and across Australia have less regular monitoring and oversight than service provider schemes. As such, in regional and remote areas where prospective shale gas resources exist, any potential impacts on drinking water may not be as readily detected. Furthermore, it is generally more difficult to remove contaminants once they are present in surface water or groundwater sources than it is to avoid contamination. It is for this reason that risk management approaches to management of drinking water are also sensible in remote and regional contexts, and depend upon the identification of risks in advance to mitigate the potential to cause harm. Additional focus on supporting private water supplies with risk management approaches, or additional scrutiny of resource proponents and the risks their activities may pose on drinking water may be prudent in areas of intensive resource development. Further research is required on the fate and transport of remnant hydraulic fracturing fluids underground, which would help inform appropriate risk management, monitoring and mitigation strategies.

7.3.3.3 Land

As mentioned in Chapter 5 and Chapter 6 the primary concern around land contamination and human health is the potential presence of contaminants such as heavy metals, NORM and other inorganics, and organics, such as aromatic hydrocarbons, from shale gas and oil horizons that are brought to the surface during shale resource development through drill cuttings and flowback fluids (Pepper *et al*., 2018), and their potential impacts on agricultural soils. Drill cuttings have the potential to impact on surrounding soils if waste rock cuttings are spread at surface (Lechtenböhmer *et al.*, 2011). However, as discussed in Chapter 5 and Chapter 6, the likely concentrations are anticipated to be so low that they will be environmentally benign (Council of Canadian Academies, 2014). If they are not, they trigger a higher degree of scrutiny and regulation around waste management. Potential land impacts on the agricultural industry are further discussed in Section 11.3. To have an impact on human health there would need to be a pathway for the exposure of humans to these contaminant at levels that may cause harm. A possible pathway is through food produced on contaminated land or irrigated with contaminated water, although the CSG Chemicals Assessment and the NT HF Inquiry both point out the difficulty in determining if this pathway is complete (NICNAS, 2017b; Pepper *et al*., 2018) The NT HF Inquiry assessed food contamination to be a low risk.

7.3.3.4 Noise, dust, amenity

Noise, dust and amenity impacts from unconventional gas and oil development are likely to be concentrated in the drilling and hydraulic fracturing stages of well development, likely to last under six weeks in most cases (Broomfield, 2012; Hawke, 2014). In at least one major review, noise impacts surrounding shale gas and oil developments were considered to be of moderate to high risk during this intensive site development stage due to the requirement for heavy vehicle traffic for drilling rigs, and transport of process and flowback fluids, however, the review states…'*but is not considered to differ greatly in nature from other comparable large-scale construction activity*.' (Broomfield, 2012). Noise and dust are most likely to be of concern where well development is sited close to settlements (Hawke, 2014). This is anticipated to be the exception rather than the norm in Queensland developments due to sparsely populated areas and the availability of directional drilling technologies. The NT HF Inquiry made several references to odours as a potential amenity impact (Pepper *et al*., 2018).

Rural areas are populated with residents who mostly value the environment for its 'rural' nature, which translates to open spaces, quiet ambience and sparse populations. As a result, studies of perceptions of rural landholders have found that impacts on amenity are a common cause of conflict in resource development areas such as for shale gas or CSG (Cook *et al.*, 2013; Huth *et al.*, 2014). Unconventional gas developments incorporate a large amount of infrastructure, requiring relatively high volumes of vehicular traffic, which is a contrast to normal volumes experienced in the rural environments within which they operate. A study of farmers' perceptions and concerns in the Surat Basin (Huth *et al.*, 2014) found that members of farm families regularly raised issues of dust, light and noise in discussions about issues affecting coexistence of CSG with farming. Furthermore, each of these environmental impacts was found to impact farm families through impacts on the individual, the environment, family home life, the farm business and health. Many of the impacts were directly related to the increased levels of traffic associated with resource development as has been observed for shale gas developments in the US (Andersen and Theodori, 2009), though it should be noted that greater population densities in the US shale regions are a compounding factor.

The amenity impacts had implications for farmers' 'sense of place' identity regarding their farm and contributed significantly to adverse impacts on farmer wellbeing (Huth *et al.*, 2014). Place identity can be described in terms of four main elements (Wester-Herber, 2004):

- distinctiveness – a place helps to describe someone and sets them apart from others. Farms can be an expression of who we are.
- continuity – memories of a place can link a person to their past or heritage. Farmers may have a long family history on a farm.
- self-esteem – a person gets positive feedback from a place with which they identify. Just as gardeners feel best in their garden, many farmers get personal strength from their farm.
- self-efficacy – a place facilitates a person's lifestyle and personal goals. The farm is the basis for the farm business, the family and much of what farmers want to achieve from life.

Impacts on place and amenity can therefore have impacts on individuals in ways beyond the way they visually encounter a landscape. It can impact upon how individuals perceive their own identity. Some of these negative psycho-social impacts are felt by rural residents in association with rapid community change, and may include fear of unknown effects of an unfamiliar industry (Wester-Herber, 2004; Adgate, Goldstein and Mckenzie, 2014; Huth *et al.*, 2014). Some impacts are also positive, in examples of rural revival from attracting a new industry to a previously reducing population, the ability to find work, increased household income and increased demand for land for rural residents wishing to exit (Fleming and Measham, 2015).

The lower number of well pads for shale gas developments compared with CSG, and the low population densities in prospective shale gas regions would likely reduce the possible impact of intensive development stages and resulting noise, amenity, and potential negative psycho-social impacts on community. Furthermore, any potential positive economic impacts may be distributed due to the distributed nature of the remote regions prospective for shale gas and oil in Queensland.

As previously discussed, increased heavy traffic near settlements may also cause a significant increase in dust, light and noise or perceived safety impacts and impacts to the nature of rural landscapes. It is anticipated that these can be managed to within acceptable limits within the existing Queensland regulatory and legislative frameworks and potential best-practice mitigation through industry measures around public consultation for the more intensive periods of development.

One of the challenges with identifying possible health impacts are that some of the potential environmental and health effects of shale gas and oil developments '*could take decades to become apparent'* (Council of Canadian Academies, 2014). Psychological impacts in terms of impacts on perceptions is also an area requiring further research. Consideration of these cumulative, long-term impacts is not only poorly supported by available research, including existing major reviews, they are also beyond the scope of this review.

7.4 Comparison to coal seam gas development

Most possible health impacts are anticipated to be similar to CSG developments, such as occupational and public health impacts and potential impacts on air quality, noise, dust and amenity. Health impacts of shale gas and oil developments are anticipated to be lower than those from CSG developments where linked to potential land contamination from flowback fluids, due to the significantly lower quantities produced in shale gas and oil developments. The impacts of drill cuttings may be similar as discussed in Chapter 2.4.

There is some potentially increased risk of drinking water pollution from accidental surface spills, due to the need for greater wastewater transport. However, there is less wastewater generated, which may offset that risk. These are covered in more detail in Chapter 4.

This may result in a slightly increased impact on amenity from shale gas and oil developments relative to CSG developments for individuals in those regions. This is due to increased vehicle movements (dust, noise, traffic) and increased potential for odours from shale gas and oil compared to CSG.

7.5 Relevant regulations

The regulation of petroleum activities to prevent or mitigate potential human health-related impacts is through the requirements of the EP Act, the P&G Act, the WHS Act and the *Public Health Act 2005* (PH Act). The EP Act applies to any activity having an impact on environmental values, which include clean air, land and drinking water. It applies to regulation of noise, dust and public amenity (nuisance) impacts in Queensland. Additional specific regulation applies to occupational health and safety, drinking water and the management of hazardous substances. The P&G Act licences authority holders to conduct petroleum activities and has operation and safety requirements.

It should be noted that, although public water supply schemes are managed and monitored by regulatory agencies, private drinking water supplies within Queensland have less regular monitoring and oversight than service provider schemes, and risk management approaches to management of drinking water may be needed in remote and regional contexts.

7.5.1 Occupational health and safety

Potential occupational health and safety impacts are regulated through the P&G Act which has requirements for the safe conduct of petroleum activities, and the WHS Act. Chapter 9 of the P&G Act and subordinate regulation has specific requirements for the safe conduct of petroleum activities. This includes requirements for safety management systems, competency, training and supervision requirements for certain workers and job safety analysis in particular circumstances

The WHS Act provides a legislative framework to protect the health, safety and welfare of all workers in the workplace. It also protects the health and safety of all other people who might be affected by the work, including the public, so that their health and safety is not placed at risk by work activities. The WHS Act places the primary health and safety duty on a person conducting a business or undertaking (PCBU). The PCBU must ensure, as far as is reasonably practicable, the health and safety of workers at the workplace (Queensland Government, 2017a). The WHS Act also has requirements for storing chemicals that are classified as dangerous to human health.

The Commonwealth IC Act applies to chemicals used in drilling and hydraulic fracturing fluids and requires the notification and assessment of the use of industrial chemicals within Australia, regulated through NICNAS. NICNAS provides guidance on processes for risk assessment of hazardous substances (or chemicals of concern) used in hydraulic fracturing, based on a recent review of their use for CSG resources. This risk assessment considers risks to workers using these chemicals, among other risks.

7.5.2 Public health

Potential impacts on public health are regulated in 3 ways. The first is the general requirement to avoid impacts on environmental values (water, land, air values) under the EP Act, EP Regs and conditions on EAs, which limit the potential for exposure of the public to potential health hazards. In addition to the conditions on an EA relevant to the protection of environmental values, there may be some specific conditions related to public health, such as:

- a requirement that waste disposal activities must not result in any negative effect on public health
- a requirement for a stimulation risk assessment to consider human health exposure pathways to operators and the regional population, including but not limited to water quality, air quality (including suppression of dust and other airborne contaminants), noise and vibration
- a requirement that petroleum activities must not cause environmental nuisance at a sensitive place (certain public spaces and protected areas), including from dust and odour.

A social impact statement is included in the EIS process for site-specific EA applications, and this will assess psycho-social stressors on the community.

The second way that potential impacts on public health are regulated is through the PH Act, which provides the legislative framework to protect public health in the state. It covers anything that is hazardous to human health, and includes specific provisions for drinking water, waste, and dispersal or release of chemicals at any place other than a workplace.

The third way that potential impacts on public health are managed are through regulations about the location and interaction of shale gas and oil activities with population centres and landholders. The RPI Act identifies and protects areas of Queensland that are of regional interest and resolves potential land use conflicts; it also protects Priority Living Areas from incompatible resource activities. The Land Access Code (Queensland Department of Natural Resources and Mines, 2016b) made under the MERCP Act provides guidance on how an operator's rights for land access should be exercised, including limiting impacts on landholders. These regulatory requirements limit the potential for exposure of the public to potential health hazards by the separation of petroleum activities from population centres.

Any potential public health impacts will require a pathway for the hazards to impact on the public. The regulations that relate to drinking water, air, and amenity pathways are summarised below.

7.5.2.1 Air

The EP Act and the *Environmental Protection (Air) Policy 2008* (Air EPP) regulate Queensland's pollution at a state level.

Nationally, the Commonwealth's *National Environment Protection Measure for Ambient Air Quality (1998)* (NEPM Air) regulates and requires monitoring of air pollution. NEPM Air sets national standards for the six most common air pollutants: carbon monoxide, lead and particles, nitrogen dioxide, ozone and sulphur dioxide. Regions with populations of more than 25,000 are also required to be monitored, and in Queensland there are nine regions: Bundaberg, Cairns, Gladstone, Mackay, Maryborough–Hervey Bay, Rockhampton, South East Queensland, Toowoomba and Townsville.

7.5.2.2 Drinking water

The management of drinking water quality in Queensland is primarily driven by a risk management framework set out by the *Australian Drinking Water Guidelines* (ADWGs), and accompanying health and aesthetic guideline values for individual water quality parameters (NHMRC and NRMMC, 2011; Queensland Department of Energy and Water Supply, 2016). The health guideline values represent safe levels for consumption over a person's lifetime. Occasional or temporary exceedances of guideline values are rarely an immediate threat to health, given high safety factors applied in their development (NHMRC and NRMMC, 2011; O'Kane, 2014). The premise of the risk management framework is that public water service providers are to manage the greatest risks to public health in priority order. This approach also recognises the high variability in source waters in Australia, which challenges the ability of providers to always meet consistent values and still prioritise health outcomes. As such, the 'guideline' approach is used in most states, rather than enforceable drinking water standards.

Regulatory oversight in Queensland is provided by the Queensland Department of Natural Resources, Mines and Energy under the *Water Supply (Safety and Reliability) Act 2008,* and focuses on a voluntary compliance approach and ongoing compliance monitoring (Queensland Department of Energy and Water Supply, 2016). Similar to most other Australian states, Queensland Health co-regulates under the PH Act and Public Health Regulation 2005, is consistent with the ADWGs, and provides expert advice on health risk and incident management (Queensland Department of Health, 2016).

In regional and remote areas in Queensland, outside treated reticulated (town) drinking water service provision areas, private drinking water supplies are used, for example in schools and in tourist attractions or remote accommodation businesses (e.g. bed and breakfast businesses) (Queensland Department of Health, 2016). In these cases, local government is responsible for the regulation of private drinking water supplies under the PH Act (Queensland Department of Health, 2016).

The conditions on an EA approval for a project, granted under the EP Act, will also have requirements for the safe storage of chemicals, management of waste (in accordance with the Waste Act) and for the protection of water values. Obligations under the Water Act for the monitoring and management of underground water resources are also referred to in the EA. This is discussed in more detail in section 4.5.2

7.5.2.3 Noise, dust, amenity

The EP Act provides the main framework for management of any form of environmental harm, and applies to any activity having an impact on the environment. The EP Act applies to regulation of noise, dust and public amenity (nuisance) impacts in Queensland. Two environmental protection policies also apply under the Act, the Air EPP and the *Environmental Protection (Noise) Policy 2008*. The EP Reg provides a regulatory regime for issues of environmental nuisance (McGrath, 2011).

The RPI Act identifies and protects areas of Queensland that are of regional interest and resolves potential land use conflicts. It protects regionally important environmental areas, strategic cropping land and living areas in regional communities, and protects high-quality agricultural areas from dislocation.

Potential impacts on the activities of agricultural landholders caused by petroleum activities are managed under the MERCP Act. Under the MERCP Act, the Land Access Code has been made (Queensland Department of Natural Resources and Mines, 2016b). It provides guidance on how an operator’s rights for land access should be exercised. By negotiation, the authority holder and landholder can work together to reduce the impacts of development, including the use of access tracks. The TO Act manages road use impacts and requires companies to implement traffic management plans.

8 Native vegetation and fauna

8.1 Summary of potential native vegetation and fauna impacts

Key potential impacts on native vegetation and fauna are:

- habitat loss or reduced habitat quality, fragmentation of habitat
- animal disturbance from noise and light pollution
- erosion, sedimentation and related impacts on aquatic biota and stream health
- flora and fauna health impacts from land and water contamination, air emissions, pipeline / wellpad construction activities and road vehicle operations.

A summary of the impacts on native plants and animals that may be caused by shale gas and oil development is provided in Table 16. The main direct impacts (as per Table 16) are disruption to animals, plants and their communities through land disturbance activities, which may have direct or cumulative effects on ecosystem functioning. There may be additional indirect effects to ecosystems through changes to water quality, quantity or availability as a result of potential contamination of air, water, or excessive extraction of water.

There is limited information in the literature on specific biodiversity impacts from unconventional gas developments, and even less information for shale gas development.

Most biodiversity impacts from shale gas and oil developments are anticipated to be similar to CSG developments. Wildlife disturbance from vegetation clearing, linear infrastructure development, light and noise, and potential air pollution impacts are all anticipated to be similar to CSG due to the similar nature and scale of these effects. These impacts are well understood from other industries and not specific to shale gas and oil developments. Shale gas and oil developments produce larger volumes of flowback water than CSG, bringing to the surface potential contaminants requiring careful management. If flowback waters are improperly managed, or if there are inadvertent events causing uncontrolled releases, then contamination impacts on the surrounding environment are possible.

A range of regulatory controls in Queensland govern biodiversity impacts, including regulation for land clearing, biodiversity conservation, and environmental protection with specifics on air, water and land protection and erosion and sedimentation.

Table 16 Summary of potential impacts of shale gas and oil development on native vegetation and fauna

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
VF.1	Clearing of vegetation for infrastructure during construction phase.	Increase in landscape disruption, habitat loss or reduced habitat quality; fragmentation and/or isolation of habitat. These impacts will be very location specific.	Biodiversity.	High to medium.	Limited to regional.	For different flora and fauna, impacts may persist for years or decades.	High.	EIS identifies flora and fauna at risk. EA model conditions – specific requirements to protect biodiversity values. EP Act general requirement to avoid harm. EO Act framework for offsetting impacts. EPBC Act has requirements to protect threatened and migratory species.	Low.	Moderate (intensity and frequency).	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Low. Regulation of land clearing for infrastructure in multiple sectors.
VF.2	Equipment and plant use during construction and operation of wells.	Increase in light and noise pollution – disruption from increased light and noise decreases fitness and survivorship of terrestrial vertebrates and invertebrates. Fauna being trapped in pipeline trenches (separate impact?) and killed on roads due to traffic strike	Native fauna.	Low.	Limited to local.	Years to decades.	High.	EIS identifies flora and fauna at risk. EA model conditions – specific requirements to protect biodiversity values. EP Act general requirement to avoid harm.	Low.	Low.	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Low. Regulation of impacts of infrastructure development in multiple sectors.
VF.3	Emission of compounds and particulate matter during operation of wells.	Increase in air pollution – decreased air quality decreases survival, growth and reproduction of terrestrial plants.	Native vegetation.	Low.	Limited to local	Months to years.	High.	EIS identifies flora and fauna at risk. EA model conditions – specific requirements to protect biodiversity values. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm.	Low.	Low.	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Low, regulation of impacts of air quality in multiple sectors.
VF.4	Surface disturbance during all phases of operation.	Increase in sediment load in surface water – decreased surface water quality negatively affects fitness and survival of aquatic plants, invertebrates and fish.	Native aquatic species.	Medium.	Local.	Depending on water volumes and sediment loads, may span days to years.	Low. This will be location dependent. May be more prevalent in arid regions during surface flow events.	EA model conditions – specific requirements to protect biodiversity values and to control erosion and sediment. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm.	Medium.	Low.	Similar. Scale and intensity of development similar, different bioregions may result in differences.	Low. Regulation of impacts of sediment run off in multiple sectors.
VF.5	Hydraulic fracturing fluids arising from subsurface migration and wellbore/casing failure during hydraulic fracturing. See related impacts WA.15 and WA.17	Contamination of groundwater – acute or chronic effects on groundwater-dependent ecosystems and subsurface fauna.	Groundwater-dependent ecosystems, subsurface fauna.	Low to medium.	Limited to local.	Depending on the chemical, may span months to decades.	Inadvertent.	EA model conditions – specific requirements to protect biodiversity values. EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	Medium.	Low.	Increased, as number of hydraulically fractured wells in shale resources significantly greater than for CSG.	Moderate. Already regulated for other petroleum activities, high prevalence of hydraulic fracturing for shale resources.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
VF.6	Spills and accidents involving chemicals during all phases of operation. See related impacts WA.5 to WA.9 and WA.11 to 12.	Contamination of surface water and/or shallow groundwater – decreased surface water quality increases levels of stress and mortality of aquatic plants, invertebrates and fish.	Native aquatic species.	Medium.	Limited (scale of spill).	Hours to days.	Inadvertent.	TO Act (road transport). EA model conditions – storage of chemicals. EA model conditions –to protect water, land and biodiversity values, and monitoring and reporting of spills and leaks. Environmental Protection (Water) Policy. WHS Act for safe storage and handling of chemicals. EP Act general requirement to avoid harm.	Medium.	Moderate (intensity).	Increased. Shale resources likely to produce liquid hydrocarbons that will require transport. Greater volume of hydraulic fracturing chemicals transported.	Low. Regulation of transport and handling of hazardous chemicals across multiple sectors.
VF.7	Leakage of wastewater during storage, treatment or disposal. See related impacts WA.5 to WA.9 and WA.11 to 12.	Contamination of surface water and/or shallow groundwater – decreased surface water quality increases levels of stress and mortality of aquatic plants, invertebrates and fish.	Native aquatic species.	Low.	Local.	Depending on the nature of the wastewater, hours to months.	Inadvertent.	EA model conditions –to protect water, land and biodiversity values, and monitoring and reporting of spills and leaks. EA model conditions for dams. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm.	High.	Low.	Similar, scale and intensity of development similar, CSG will have more produced water, shale resource waste water lower quality.	Low. Regulation of impacts of water release in multiple sectors.
VF.8	Freshwater extraction for hydraulic fracturing from surface water resources. See related impact WA.2	Decrease in stream flow and downstream water quality– low stream flow rates and water volumes reduce available habitat, increase mortality and change assemblage composition of aquatic plants and animals.	Freshwater ecosystems.	Medium.	Local.	Depending on water volumes, may span days to months.	Low (if surface water resources used). Quantities taken need to be enough to impact ecosystems.	Water Act applies to extraction of water from the environment. RPI Act also protects water resources. EA model conditions –to protect water and biodiversity values. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems.	Medium.	Moderate (intensity). Dependant on water resources used.	Increased (if used), shale gas and oil likely to require greater volumes of water for hydraulic fracturing.	High. Already regulated for other multiple sectors, high prevalence of hydraulic fracturing for shale resources will mean high levels of water use.
VF.9	Water extraction for hydraulic fracturing from shallow groundwater resources). See related impact WA.1	Reduction of groundwater levels – acute or chronic effects on groundwater-dependent ecosystems and subsurface fauna.	Groundwater-dependent ecosystems, subsurface fauna.	Medium.	Local.	Depending on water volumes and recharge rates, may span years to decades.	Low (if groundwater resources used). Drawdown needs to be enough to have an impact on groundwater dependant ecosystem.	Water Act applies to extraction of water from the environment. Make good obligations under Chapter 3 of the Water Act EA model conditions –to protect water and biodiversity values. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm. EPBC Act applies to matters of national environmental significance, including some freshwater ecosystems.	Medium.	Moderate (intensity). Dependant on water resources used.	Greater (if used) shale gas and oil likely to require greater volumes of water for hydraulic fracturing. CSG has significantly more produced water.	High. Already regulated for other sectors, high prevalence of hydraulic fracturing for shale resources will mean high levels of water use.

8.2 Context

This section considers the potential impacts of shale gas and oil developments on native vegetation and fauna in both aquatic and terrestrial ecosystems. Impacts have been divided into two groups, which are as follows:

- Deterministic Impacts – These impacts are unavoidable outcomes of shale gas and oil development and cannot be prevented. These impacts will occur whenever this type of development is undertaken. Examples of deterministic impacts include: vegetation clearing and surface disturbance during well construction, and light, noise and air pollution during operation of wells.
- Probabilistic Impacts – these are potential impacts of shale gas and oil developments that can potentially be avoided. These impacts occur with some frequency but are not inevitable. The latter group includes accidents, natural hazards or systems failures.

Many of the impacts on native flora and fauna from shale gas and oil developments are similar to those from other resource activities, such as clearing of vegetation. A few impacts are more specific to shale gas and oil developments and some CSG activities, such as impacts from flowback waters containing potentially harmful contaminants. Both types of impacts are considered here, although current scientific understanding of the effects of those that are more specific to shale resource development is limited, reducing the ability to predict potential outcomes. Impacts on flora and fauna caused by the use of, spillage of, or accidents with materials and processes that are part of agricultural, manufacturing or other anthropogenic activities, have not been used here for comparison.

8.3 Impacts

8.3.1 Terrestrial impacts

Habitat fragmentation impacts

The impact from shale gas and oil development that will occur at the largest spatial scale is landscape disruption resulting from well preparation and drilling and development of associated infrastructure (VF.1 in Table 16). The extent of this impact will vary with geographic location and will depend partially on the land use history of the region (Cook *et al*., 2013). Specifically, a region that has already experienced landscape-scale disruption from other disturbances is likely to support a biota that is resilient to landscape change. This sort of landscape disturbance will affect ecosystems and species through habitat clearance and fragmentation. Environmental effects begin at a local scale with an average of 1.5 to 3.0 ha of vegetation cleared through the development of a single well pad (Entrekin *et al*., 2011). Section 2.5.1 and Table 3 provide a detailed discussion of likely well spacing and area at scale. Habitat fragmentation is a complex process that results in negative changes in the ecology of the impacted area including the spread of invasive plant species, changes in species interactions (e.g. some animals experience increased predation) and changes in species assemblages, with more generalist species becoming more abundant (Cook *et al*., 2013; Brittingham *et al*., 2014). The resilience of landscapes declines with fragmentation as connectivity decreases and risks associated with dispersal increase. Such effects occur in both terrestrial and aquatic environments.

Light, noise and construction impacts

The construction and operation of wells and equipment, particularly during the well drilling (field development) stage creates localised light and noise pollution that can result in disturbance to wildlife (VF.2 in Table 16). Noise pollution has been shown to particularly impact birds, which are dependent on sound for communication. The effects of noise pollution on birds include individual avoidance and reduced abundance, reduced reproductive output and changes in behaviour (Brittingham *et al*., 2014).

Impacts from pipeline and road construction can lead to wildlife being trapped in trenches as well as increased potential for animals being impacted through traffic strike (increased due to increased traffic and the development of new roads).

The spread of invasive species (as discussed Section 11) can also be an impact with invasive plants and potentially invasive animals being transported (on/in vehicles) or having easier access because of the development activities.

8.3.2 Aquatic impacts

Shale gas and oil production involves the use of water for hydraulic fracturing and other activities. Extraction of water for these processes can potentially impact groundwater-dependent ecosystems and subsurface fauna (Cook *et al*., 2013), although the exact impacts are poorly understood (Lechtenböhmer *et al*., 2011). These potential impacts on aquatic ecosystems are covered here.

Water extraction impacts

The use of water for drilling and hydraulic fracturing (Impact VF.8 from Table 16) can affect groundwater and surface water recharge when it is extracted from the natural environment. Surface water extraction can alter local hydrology, resulting in reduced stream flow rates and water volumes (Souther *et al*., 2014) and consideration of this would be made by the licencing authority. In freshwater, these changes can potentially result in:

- increased water temperature
- increased concentrations of pollutants
- decreased availability of dissolved oxygen for aquatic plants and animals.

If the amount of available freshwater decreases, then more severe and obvious environmental effects will result, for example:

- reduction in critical spawning habitat
- drying out and death of species of macroinvertebrates that cannot follow the availability of water
- fragmentation of streams in to isolated pools (Brittingham *et al.*, 2014).

A reduction in stream flow rates can lead to reduction in downstream water quality because less water is available to dilute contaminants (Entrekin *et al.*, 2011).

In Queensland, it is expected that groundwater will be the primary source of water for shale gas and oil developments. Connectivity of groundwater and surface water resources will define the degree of impact on surface water resources from groundwater extraction. Where groundwater recharges surface waters elsewhere in a catchment (e.g. Duvert *et al*., 2015), extraction of groundwater can also have consequent downstream surface water impacts as outlined above (Mudd, 2000).

Sedimentation and siltation impacts

The contribution of a given shale gas or oil development to sediment load will vary according to the number of wells, the location, and catchment and local conditions such as weather conditions (which primarily drive any potential site run off), management practices, hydrology, geology, ground cover, existing land use and management practices (Impact VF.4 in Table 16). The construction of well pads and associated infrastructure can locally increase sediment in surface water runoff, potentially resulting in increased suspended and benthic sediment in streams and other surface waters (Entrekin *et al*., 2011). Increased turbidity can impact on the health and viability of aquatic life. Sedimentation can cause diversion, shallowing and overall flow changes if not appropriately managed. The incidence and severity of stream siltation has increased with well density and proximity to surface water (Souther *et al*., 2014).

Water contamination impacts

There are a range of activities during each stage of operation which, if not managed and regulated properly, could potentially lead to contamination of surface water and/or shallow groundwater with chemicals, with consequent impacts on aquatic biota (Impacts VF.5, 6 and 7 in Table 16). Examples of shale resource development activities that may result in water contamination include inadvertent onsite leaks and spills from handling of hydraulic fracturing fluids prior to injection, well blowouts, well casing failures and spills during fluid transport and storage (Cook *et al*., 2013; Souther *et al*., 2014).

Hydraulic fracturing may cause contamination of groundwater if hydraulic fracturing fluids enter aquifers either by subsurface migration or wellbore/casing failure (Impact VF.5 from Table 16) (Cook *et al*., 2013; Souther *et al*., 2014). The likelihood of this occurring is actively debated (e.g. Council of Canadian Academies, 2014) and therefore, there is a drive to seek food-grade additives that will not cause harm if released (Cook *et al.,* 2013).

Accidental releases of hydraulic fracturing fluid or flowback waters, which may contain dissolved solids (e.g. brine, elevated levels of heavy metals, hydrocarbons, NORM (as discussed previously in Section 4.3.2)), could be toxic to aquatic life that occurs in surface waters, such as invertebrates and fish, and aquatic plants, potentially reducing food and oxygen sources for fauna (Impact VF.6 in Table 16). Effects of these contaminants, if released, are likely to include increased levels of stress (e.g. gill lesions in fish), increased mortality, and changes in assemblage structure of periphyton, benthic macroinvertebrates and fish (Brittingham *et al*., 2014; Souther *et al*., 2014). If impacts occur to species within aquatic assemblages these changes may subsequently spread to species elsewhere in the ecosystem such as to predators of macroinvertebrates and fish.

As has been discussed in previous chapters (Chapters 4 and 6), accidental releases of wastewater during storage, treatment or disposal could also cause contamination of surface water and/or shallow groundwater. Examples of inadvertent events that may result in this type of contamination include contamination from leakage and overflow (after precipitation) of wastewater, from containment ponds, and migration from deep injection wells. Accidental releases could affect aquatic or terrestrial plants and animals depending on the toxins and their specific concentration (Impact VF.7 from Table 16).

8.3.3 Air impacts

Shale gas and oil activities may impact air quality from emission of compounds and particulate matter, primarily from the burning of diesel to run equipment, as well as from leaks of produced gas (see section 9). Shale gas and oil operations emit a range of air contaminants from drilling, hydraulic fracturing, high-pressure compressors and other equipment that are harmful to plants and animals when present in high enough concentrations (Impact VF.3 in Table 16). While this review has not been able to find examples of air quality impacts on flora or fauna from shale gas and oil activities in the literature, Kiviat (2013) and Souther *et al* (2014) both raise this potential impact as an area that requires further study. Souther *et al* (2014) have assessed that this impact would have a limited spatial and temporal effect. They give an example of the potential impacts, such as VOCs emitted during shale gas and oil operations contributing to ozone formation, which is a pulmonary and respiratory irritant in mammals (Souther *et al.*, 2014). Kiviat (2013) also cite studies that have shown impacts on flora in the vicinity of roads in England attributed to similar air emissions.

8.4 Comparison with coal seam gas development

Most biodiversity impacts of shale gas and oil developments are anticipated to be similar to those of CSG. Wildlife disturbance from vegetation clearing, light and noise, pipeline trench entrapment, traffic mortality and potential air pollution impacts are all anticipated to be similar to CSG due to the similar nature and scale of these effects.

As previously stated, the primary differences between CSG and shale gas and oil developments are the amount of water produced and the amount of water used. Every shale gas well requires hydraulic fracturing to extract the gas, consuming water in the process, while less than 10% of CSG wells require this process (Stone*.* 2016). The differences in water requirements for shale gas and oil developments when compared to CSG therefore has the potential for greater impacts caused by changes in water quality, quantity and availability – both locally and further downstream or in connected groundwater-dependent ecosystems (as CSG water requirements are lower). However, as discussed in Section 2.3, the water requirements of unconventional gas are insignificant in the context of other licensed water users (Hawke, 2014).

Shale gas and oil developments will also produce larger volumes of flowback water, bringing to the surface potential contaminants potentially requiring careful management (as discussed in Section 2.3 and Chapter 6). If flowback waters are improperly managed, or if there are inadvertent events causing their uncontrolled release, then impacts on the surrounding environment are possible.

8.5 Relevant regulations

The EP Act and EP Reg form the main regulatory framework under which environmental impacts on native vegetation and fauna, including impacts on ecosystems and biological diversity, are managed in Queensland. A project's EA will set out requirements for protection of biodiversity values. Additionally, the general requirement to avoid impacts on environmental values (water, land, air values) under the EP Act, EP Regs and conditions on EAs, limit the potential for exposure of native vegetation and fauna to potential hazards.

An EA for petroleum activities has requirements and conditions that the authority holder must comply with to prevent potential impacts on biodiversity values related to erosion and land contamination. These conditions are based on an assessment during the application process of on-the-ground biodiversity values of any native vegetation communities that may be significantly disturbed. The standard conditions for exploration activities (Queensland Department of Environment and Heritage Protection, 2015b) and the streamlined model conditions for petroleum activities (Queensland Department of Environment and Heritage Protection, 2016a) for the protection of biodiversity values include:

- setting site planning principles to minimise biodiversity impacts
- setting conditions for any planned and authorised disturbance of Environmentally Sensitive Areas (ESA) and surrounding protection zones, in accordance with the category of the ESA, along with monitoring and reporting requirements
- prohibiting impacts on prescribed environmental matters (including but not limited to regulated vegetation, certain wetlands and watercourses, precincts in ESAs, protected wildlife habitat, designated fish habitats, and protected areas)
- setting out any environmental offsets required as a condition of the activities
- limiting the size of disturbed areas and setting requirements for rehabilitation of disturbed sites.

The conditions in the EA reflect and work alongside other legislation. For example:

- The *Nature Conservation Act 1992* (NC Act) protects native plants. The clearing of protected plants requires a permit to be issued under the NC Act.
- The Nature Conservation (Wildlife Management) Regulation 2006 (the Wildlife Regulation) contains regulations concerning tampering with animal breeding places. A permit is required to tamper with animal breeding places.
- The *Environmental Offsets 2014* Act (EO Act) coordinates the delivery of environmental offsets across jurisdictions in Queensland. Environmental offsets allow for development to be approved in one place on the basis of a requirement to make an equivalent environmental gain in another place, and are an option for shale gas and oil developments. The RPI Act identifies and protects areas of Queensland that are of regional interest and resolves potential land use conflicts, including Strategic Environmental Areas (SEA). SEAs are areas that have been identified as containing regionally significant environmental attributes (for example biodiversity, water catchments and ecological functions). Development is allowed within these areas where it can be demonstrated that the ecological integrity of the SEAs is not jeopardised.
- In some circumstances, the Water Act requires impacts on water-dependent ecosystems to be assessed where water is taken or interfered with.

The Commonwealth EPBC Act may also apply if the proposed activities might impact on a MNES. MNES include world and national heritage values and declared properties, Ramsar wetlands, EPBC Act-listed threatened species and ecological communities, listed migratory species, Commonwealth marine areas and the Great Barrier Reef Marine Park. Water resources are an MNES for coal mining or CSG development; however, they are not for other activities, including shale gas and oil. If the EPBC Act is triggered, the activity requires approval from the Australian Government Minister for the Environment, who will determine the assessment process.

Erosion and sedimentation regulation is discussed in some detail in Section 5.3.1. Additionally, the *Soil Conservation Act 1986* provides a legal framework for the management of soil erosion from agricultural land, but not specifically lands of conservation value. Project areas may be declared to manage soil erosion in a specified area, and have been declared around Toowoomba, Bundaberg and Kingaroy (McGrath, 2011).

Water impacts may lead to impacts on native vegetation and fauna. See section 4.5 for further discussion. See section 9.5 for a discussion of regulations relevant to air quality.

9 Air quality and greenhouse gas emissions

9.1 Summary of air quality and greenhouse gas emissions impacts

Shale gas and oil projects, like all industrial development, have a greenhouse gas footprint. These gases contribute to climate change, the impacts of which are beyond the scope of this report. However, the contribution of shale gas and oil projects to global greenhouse gas emissions has been discussed. The key sources of emissions are:

- direct emissions from the combustion of fuels for power generation, stationary equipment and transport and changes to land use (land clearing)
- indirect emissions embodied in materials required for shale gas and oil projects
- methane emissions during the development stages of shale gas and oil projects (drilling, hydraulic fracturing)
- fugitive methane emissions (leaks from infrastructure) over the life of a shale gas and oil project
- emissions of carbon dioxide from high carbon dioxide containing reservoirs.

Greenhouse gas emissions is an area of active research. While the direct and indirect emissions associated with shale gas and oil projects are reasonably well understood (the first two points listed above), there is uncertainty and debate in the literature about emissions during the development stages and fugitive emissions from infrastructure. These uncertainties arise from the difficulties in measuring these emissions.

There is no regulation of the amount of greenhouse gas that can be emitted by petroleum developments in Queensland. The amount of emissions, as well as steps to mitigate these emissions, must be discussed in a project's EIS and EA application. The P&G Act places restrictions on venting or flaring of gas and these restrictions reduce methane emissions. All emissions must be reported under Commonwealth legislation.

In addition to greenhouse gases, shale gas and oil projects have the potential to have air emissions that can impact on air quality. The primary concerns are:

- emissions of air pollutants from flaring and combustion engines
- emissions of air toxicants such as volatile organic compounds (VOCs) from gas infrastructure.

The emissions from combustion of fuel is well understood and are the same as those for any other industry reliant on the use of combustion engines and these emissions are well covered in the literature. Emissions of pollutants that are a component of the natural gas stream are not as well understood and will be dependent on their concentration in produced gas and the amount of gas emitted.

Potential air quality impacts are regulated under the EP Act. A project's EA will set out requirements for allowable emissions, monitoring requirements and processes for addressing complaints.

9.2 Context

The development of the shale gas and oil sector will result in the emission of greenhouse gases as well as having the potential to impact on air quality. All industrial developments have the potential to emit greenhouse gases either directly or indirectly and shale gas and oil projects are no different. As well as greenhouse gases, unconventional gas production may contribute to local air quality issues due to emissions from infrastructure (such as generators, water pumps and gas compression plants) and more diffuse leakage (often called fugitive emissions) of other hydrocarbons that sometimes occur with the resource. This section discusses greenhouse gas and air quality implications of a potential shale gas and oil industry in Queensland.

In this section only greenhouse gas emissions from the upstream component of shale gas and oil developments are considered. The emissions from the use of shale gas and oil have not been considered, except to note that emissions of carbon dioxide (CO_2) from natural gas combustion are usually less, per unit of energy produced, than from other fossil fuels. When used for electricity generation, for instance, direct greenhouse gas emissions from a high-efficiency gas-fired generation plant may be less than half of those emissions from a comparable coal-fired plant (Cook *et al.*, 2013).

9.3 Impacts

9.3.1 Greenhouse gas emissions

Emissions of greenhouse gases (GHG) generated by human activities are causing climate change. The impacts of climate change are the result of cumulative emissions of GHGs worldwide and cannot be attributed to any single project. A discussion of the impacts of climate change in Queensland is beyond the scope of this report. Information on the potential impacts of climate change in Queensland can be found on the Queensland Government's Climate Change website (Queensland Government, 2017b). This section discusses the contribution of a shale gas and oil industry to Queensland's overall GHG emissions (see impact AQ.1, impact AQ.2 and impact AQ.3 in Table 17).

The main GHGs are carbon dioxide, methane and nitrous oxide. Methane has a global warming potential of at least 25 times that of carbon dioxide (over a 100-year period), and nitrous oxide's global warming potential is at least 265 times that of carbon dioxide. The global warming potential allows comparisons of the global warming impacts of different gases by measuring the amount of energy that will be absorbed by 1 t of an emitted gas over a given period of time relative to 1 t of emitted carbon dioxide. Natural gas is primarily composed of methane and, given its high global warming potential, it is important to account for emissions of methane during production in order to consider the GHG impact of natural gas utilisation. Even relatively small losses of methane to the atmosphere during production, processing and transportation may significantly reduce any greenhouse advantage of using natural gas (Wigley, 2011; Alvarez *et al.*, 2012).

Table 17 provides a summary of the potential air quality and GHG emissions impacts from shale gas and oil developments.

Table 17 Summary of potential air quality and greenhouse gas emissions impacts from shale gas and oil developments

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Greenhouse gas related impacts												
AQ.1	Methane emissions from hydraulic fracturing (methane produced with flowback water) or during well completion or workovers.	Greenhouse gas emissions.	Long-term climate.	Low. Impacts that can be attributed to a single shale resource development only a small component of climate change impacts.	Limited. Event at the scale of the activity (well pad). Impact is global as a result of contribution to greenhouse gasses.	Years to decades.	High – emissions occur during flowback, completion and workovers. Green completion methods have been shown to reduce emissions.	P&G Act restricts venting of methane, and requires management of gas on safety grounds. EA model conditions – specific requirements to protect air values restrict venting. Considered as part of EIS process. Cwlth National Greenhouse and Energy Reporting requirements apply. No regulations capping or restricting emissions.	High.	Low (global context).	Increased since all shale gas wells require hydraulic fracturing.	Moderate. Greenhouse gas emissions associated with any development activity of increasing concern.
AQ.2	Methane emissions from infrastructure, including venting and fugitive emissions.	Greenhouse gas emissions.	Long-term climate.	Low. Emission rates are relatively low.	Limited, event at the scale of production infrastructure. Impact is global.	Years to decades.	High – emissions occur throughout gas field. Improved leak detection and repair, and adoption of low emission equipment has been shown to reduce emissions.	P&G Act restricts venting of methane, and requires management of gas on safety grounds. EA model conditions – specific requirements to protect air values restrict venting. Considered as part of EIS process. Cwlth National Greenhouse and Energy Reporting requirements apply. No regulations capping or restricting emissions.	Moderate.	Low (global context).	Same – gas processing infrastructure is similar to CSG.	Moderate. Greenhouse gas emissions associated with any development activity of increasing concern.
AQ.3	Carbon dioxide emissions from high carbon dioxide-bearing reservoirs.	Greenhouse gas emissions.	Long-term climate.	Low. Impacts that can be attributed to a single shale resource development only a small component of any climate change impacts.	Local to carbon dioxide bearing developments. Impact is global.	Years to decades.	Low. Requires development of shale resources that contain carbon dioxide. Resource specific. Commercially unfavourable (production of unsellable gas).	Considered as part of EIS process. Cwlth National Greenhouse and Energy Reporting requirements apply. No regulations capping or restricting emissions.	High.	Low (global context).	Increased. CSG resources do not typically have high carbon dioxide content, or are uneconomic to produce if they do.	Moderate. Greenhouse gas emissions associated with any development activity of increasing concern.
Air quality impacts **See related impacts H.4 and VF.3, which are impacts that result from changes to ambient air quality.**												
AQ.4	Storage and transmission of hydrocarbons releasing VOCs to the atmosphere (potentially BTEX).	Decrease in air quality.	Ambient air quality.	Low to moderate depending on quality of resource. High liquid content expected to have a larger effect.	Limited to local, may be significant at processing facilities where gas and liquids are separated.	Years.	High. Some change to air quality inevitable.	EA model conditions – storage of chemicals. EA model conditions – requirements to protect air values. Environmental Protection (Air) Policy. EP Act general requirement to avoid harm. National Environment Protection (Ambient Air Quality) Measure 1998 (Cwlth)	Moderate.	Low (intensity).	Greater – Shale gas may contain other hydrocarbons (CSG does not contain significant levels of VOCs).	Low. Regulation of impacts of air quality in multiple sectors.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
AQ.5	Release of pollutants from engine exhaust.	Decrease in air quality.	Ambient air quality.	Low to moderate (depending on proximity to populated areas).	Limited to local, drilling operations and fixed processing facilities with engines.	Days to weeks at drilling operations – years to decades at processing plants.	High, some change to air quality inevitable.	EA model conditions – storage of chemicals. EA model conditions – requirements to protect air values. Environmental Protection (Air) Policy. EP Act general requirement to avoid harm. National Environment Protection (Ambient Air Quality) Measure 1998 (Cwlth).	Moderate.	Low (intensity).	Same – drilling rigs, transport, processing facilities similar to both CSG and shale gas.	Low, regulation of impacts of air quality in multiple sectors.

Emissions during production, transport and processing

In shale gas and oil projects, carbon dioxide emissions will arise from the combustion of fuels to provide power within shale gas and oil field; combustion of fuel for construction equipment, drilling rigs, other field equipment, and for transportation; venting of carbon dioxide captured during the processing of gas; and from the flaring of gas. Methane emissions will arise from methane released during drilling and completion of wells; venting of methane from infrastructure; leakage of methane from infrastructure (from wellheads, compression stations, pipelines, also known as fugitive emissions), and as a small component in the exhaust of gas combustion for power generation (during operational phase). Nitrous oxide emissions are byproducts of the combustion of other fuels in air and are minor components of GHG emissions in shale gas and oil projects. Land clearing will also result in carbon dioxide and methane emissions due to the breakdown of organic matter. There will also be GHG emissions indirectly related to a shale gas and oil project in the supply chain for equipment and materials used within the project (e.g. in the construction of steel casing).

Cook *et al*. (2013) analysed the GHG emissions over the life of the shale gas project, based primarily on North American examples. They considered emissions during the production, processing, transmission and distribution stages of natural gas. They estimated GHG emissions during production, processing, transport and distribution of natural gas of around 18 g CO_2e/MJ (carbon dioxide emissions per megajoule) of natural gas produced, with a range of 9 to 29 g CO_2e/MJ. The combustion of natural gas (methane) releases 57 g CO_2e/MJ for comparison. However, as authors noted, these estimates of fugitive emissions were subject to large uncertainties due to the uncertainty of the data available at the time. The Council of Canadian Academies (2014) reported similar levels and uncertainties for GHG emissions for shale gas projects.

During the development stages of a shale gas and oil project, one of the primary activities is the construction of production wells. During the drilling process, methane can be entrained in drilling fluids and formation fluids that enter the well and released at the surface. After hydraulic fracturing, the flowback water may also contain significant quantities of methane. This methane could be vented directly to atmosphere, captured and flared (reducing its global warming potential by converting it to carbon dioxide and water), or captured and used. The current practice in North America involves a combination of capture (70%), flaring (15%) and venting (15%), although there is debate about these percentages (Cook *et al.*, 2013; Council of Canadian Academies, 2014). Methane emissions from flowback water are discussed further below.

Natural gas resources, including gas and oil resources, can contain varying amounts of carbon dioxide. For example, some gas resources in the Cooper Basin have carbon dioxide compositions over 20% (Boreham, Hope and Eromanga, 2001). This carbon dioxide is removed in processing facilities and vented to the atmosphere, contributing to the overall GHG emissions of a project (Cook *et al.*, 2013; Council of Canadian Academies, 2014).

Sources of methane emissions and uncertainties

Over the last few years there has been some concern that methane emissions from unconventional gas production is higher than national greenhouse gas inventories would suggest (Schwietzke *et al.*, 2016). As a result, there have been several studies aimed at determining methane emissions from shale gas production, especially in the US. In Australia, fugitive methane emissions are estimated and reported annually under the National Greenhouse and Energy Reporting legislation (Clean Energy Regulator, 2016). However, at present, no distinction is made for reporting purposes between conventional and unconventional gas, and in any case, there are currently only very few producing shale gas wells in Australia. Most of the Australian research into fugitive emissions from unconventional gas production has been focussed on CSG production (Day *et al*., 2014; Day *et al*., 2015; Day *et al*., 2016; Ong *et al*., 2017). Consequently, there is no reliable information on GHG emissions or atmospheric emissions in general from

Australian shale gas production. Much of the current understanding on methane emissions is the result of recent North American studies.

Methane emission rates are often expressed as the amount of gas lost as a proportion of total production. Reported estimates of fugitive emission rates from shale gas production in the US have varied considerably, ranging from less than 1% up to more than 17% (Pétron *et al.*, 2012; Allen *et al.*, 2013; Karion *et al.*, 2013, 2015; Caulton *et al.*, 2014; Peischl *et al.*, 2015, 2016). However, there is a significant degree of uncertainty associated with these emissions. For example, Caultron *et al*. (2014) estimated emissions from the Marcellus Shale in Pennsylvania to be within the range of 2.8% to 17.3% of production. A more recent study of emissions from the same area found much lower emission rates corresponding to between 0.18% and 0.41% of gas production (Peischl *et al.*, 2015). On a global scale, Schwietzke *et al*. (2016) concluded that while methane emissions from fossil fuel industries are between 20% to 60% higher than inventory estimates, emissions from natural gas production have declined from about 8% of production during the 1980s to 2% of production in 2015, despite a large increase in the size of the industry over this period. The reduction in emissions is attributed to improvements in management practices and technology and replacement of older equipment.

Although some of the reported estimates of emissions from unconventional gas production have been high, it is becoming clearer that high levels of emissions are not necessarily occurring across the entire industry. Brandt *et al*. (2014) suggested that it was likely that most emissions were derived from a relatively small number of large sources. The results of the Caultron *et al*. (2014) study also demonstrated that emissions were concentrated on a small proportion of facilities; out of a total of 3,400 wells in the study region, as much as 30% of the observed emissions originated from only 40 wells.

As described above, one of the potential emission pathways from shale gas operations occurs immediately after hydraulic fracturing when fluid injected into the well flows back to the surface (flowback). Flowback periods may last from less than a day to several weeks (O'Sullivan and Paltsev, 2012; Allen *et al.*, 2013) during which large volumes of methane also flow from the well. If all of this methane is vented, then potentially several hundred tonnes or more of methane may be released to the atmosphere from each event (O'Sullivan and Paltsev, 2012; Cook *et al.*, 2013). Because of the potentially high GHG impact of venting, the US unconventional gas industry has been encouraged through the US Environmental Protection Agency's Natural Gas STAR Program to adopt practices to reduce or eliminate atmospheric emissions of methane (US Environmental Protection Agency, 2016b). Among these practices are 'reduced emissions completions' (REC) where methane that would otherwise be vented is captured for sale or utilisation. Alternatively, methane may be flared onsite to reduce direct methane emissions by converting it to carbon dioxide and water. These mitigation measures are now widely practised throughout the US unconventional gas industry and are reported to be effective at reducing emissions from hydraulic fracturing operations. O'Sullivan and Paltsev (2012) estimated that based on probable industry practice, methane emissions from flowback were less than 25% of what it would be by venting alone. The O'Sullivan and Paltsev (2012) analysis was based on a number of assumptions so it must be considered an approximation. However, subsequent field measurements of emissions from hydraulic fracturing have confirmed the effectiveness of these methods. Allen *et al*. (2013) found that in many cases, actual emissions from flowback would only be a few percent of the potential emissions had no mitigation been used.

Most of the reported studies on shale gas emissions have been focused on producing regions. In a different approach, Pinti *et al*. (2016) determined human activity related and natural methane emissions from a shale gas exploration region in Canada using measurements of methane concentrations in groundwater. They then compared their results to emissions from flowback projected to occur over a 10- to 20-year period. Their results showed that currently the greatest methane source in the study region is degassing of groundwater entering rivers, followed by natural diffuse seeps and finally methane emitted from water extraction for agriculture or domestic use. The estimates of the total amount of methane that would be released from hydraulic fracturing operations in the gas field over a 10- to 20-year period were between 0.3 and 66 times that released from groundwater discharge over the same period. While this is an important piece of work because it considered baseline emissions, the very large range of the estimates illustrates the uncertainties associated with these estimates.

Research into determining background levels of methane in gas production regions is continuing around the world. In Australia, work is currently underway in the Surat Basin and NSW to measure background methane emissions (from natural sources, agriculture and mining activities) to properly assess the climate-change related impact of CSG production in these regions (Day *et al.*, 2015). It is likely that the methodology being developed will be applicable to shale gas basins. Like all natural gas production, encouraging the use of best practice methods throughout a shale gas industry, such as reduced emissions completions, is likely to mitigate methane emissions (Cook *et al.*, 2013).

9.3.2 Air quality

In addition to GHG emissions, other atmospheric emissions may result from shale gas and oil production (see impact AQ.4 and impact AQ.5 in Table 17). Potential emission sources include diesel powered vehicles and other equipment such as drilling rigs, gas processing facilities, flares and phase separators (to remove water and condensate from gas) and condensate/oil storage tanks. Substances emitted due to combustion (i.e. engines and flaring) may include oxides of nitrogen (NO_x), carbon monoxide (CO), VOCs and particulate matter (PM). Ozone may also be produced as a result of photochemical reactions of VOCs and NO_x in the presence of sunlight. In addition, air toxic compounds, which include formaldehyde, benzene, toluene, xylene, polycyclic aromatic hydrocarbons (PAHs) and other hazardous air pollutants may be emitted to the atmosphere. While these compounds are generally at trace levels, it has been suggested that aggregated emissions from large-scale gas development may have regional air quality implications (Council of Canadian Academies, 2014).

Many of the emissions from surface infrastructure are likely to be similar across both shale gas and CSG production. However, shale gas may also occur with heavier hydrocarbons (condensate) that are not found in association with CSG. As a result, shale gas operations may require additional equipment to separate and collect condensate from the gas stream. This additional processing step is likely to be a source of atmospheric emissions of VOCs.

In Australia, there is currently very little information on the effects of CSG (or shale gas) production on air quality, although research is currently underway in the Surat Basin by the Gas Industry Social and Environmental Research Alliance (GISERA). Some of the major reviews of shale gas do not consider impacts on air quality (Cook *et al.*, 2013; Hawke, 2014), whereas others consider the issue but conclude that there is insufficient data, including background levels, to properly assess air quality impacts in prospective regions (Council of Canadian Academies, 2014).

In the US, some studies of the Denver Julesburg Basin in Colorado indicated significant emissions of various hydrocarbons that were much higher than previously suggested (Pétron *et al*., 2012; Pétron *et al*., 2014). More recently, due to concerns about the regional impact of shale gas production in the US, several other studies have been undertaken to examine emissions of VOCs in various shale regions (Swarthout *et al.*, 2015; Lyon *et al.*, 2016). Swarthout *et al*. (2015) measured atmospheric concentrations of a range of hydrocarbons in the Marcellus Shale region in Pennsylvania and found elevated levels of these compounds in areas with the highest density of shale gas production wells. Although gas wells were found to be relatively small contributors to alkenes and aromatic compounds, the research concluded that the generally higher levels of VOCs in the gas production region was likely to adversely affect ozone levels in ambient air.

In another recent study, Lyon *et al*. (2016) used an infrared imaging system mounted on a helicopter to monitor VOCs leaking from unconventional gas and oil production sites in seven basins across the US. The sensitivity of their instrument was quite low with a detection threshold of 1 to 3 g per second but nevertheless found a significant proportion of sites with hydrocarbon emissions. In the Bakken shale gas region of North Dakota, 14% of surveyed sites had hydrocarbon emission rates greater than the detection threshold. More than 90% of the emissions sources detected were from storage tank vents and hatches and it was suggested that current US inventories of VOCs from these facilities may be underestimated.

In a study of emissions near gas wells in Colorado, Colborn *et al*. (2014) measured ambient concentrations of a range of VOCs including eight PAHs via weekly air sampling over the course of a year. The samples were collected 1.1 km from the well pad of interest. Sampling was conducted before, during, and after drilling and hydraulic fracturing at a new natural gas well pad. Their results showed the presence low levels of various compounds such as methane, ethane, and other alkanes that are typical of emissions near natural gas production sites throughout the year. A number of other organic compounds were detected in some of the weekly samples although the concentrations detected were low, some of these compounds are known to be toxic with potential for significant human health effects. The paper notes that the concentrations at which these chemicals were detected were well below US government safety standards. However, the authors noted that other studies have suggested that developmental issues in children may be associated with PAH concentrations lower than found at the Colorado site. The authors state that none of the compounds detected at the test site could be causally linked to gas production, and cited a lack of baseline data as a limitation of the study.

So far, most of the research into atmospheric emissions from shale and other forms of unconventional gas that has been reported to date has been concerned with GHGs. However, there is now a significant body of literature that indicates that gas production may affect air quality in some cases, although some of the results are inconclusive. It is apparent therefore that further work is required to fully understand the nature and scale of any local or regional air quality implications of widespread shale gas development, especially in the Australian context.

9.4 Comparison with coal seam gas development

In Australia, there is currently little information on the effects of shale gas or CSG production on air quality, though research conducted by the Gas Industry Social and Environmental Research Alliance (GISERA) currently has shown that CSG activities are having little impact on air quality (Lawson *et al.,* 2018).

Many of the emissions from surface infrastructure in shale gas and oil development are likely to be similar to CSG. However, shale gas may have heavier hydrocarbons (condensate) that are not found with CSG. As a result, shale gas and oil operations may require additional equipment to separate and collect condensate from the gas stream. This additional processing step may be a source of VOCs and other hydrocarbons.

There may be an increased potential for methane emissions from shale gas and oil activities compared to CSG from flowback water if methane is not captured during this process. Methane emissions from well construction and workovers are expected to be similar, dependent on operational aspects. Shale gas and oil resources may also contain carbon dioxide that is removed during processing of produced gas. The carbon dioxide may be vented, contributing to the greenhouse gas emissions, or stored underground. CSG activities in Queensland have so far avoided resources with a significant carbon dioxide component.

9.5 Relevant regulations

The regulation of petroleum activities to prevent or mitigate potential air-related impacts is primarily through the requirements of the EP Act to protect air values, and the conditions in an activity's EA.

In preparing an application for an EA, the authority holder must outline the environmental values of the air environment that may be impacted, including consideration of the health and biodiversity of ecosystems, human health and wellbeing, aesthetics of the environment (including the built environment), and agricultural use of the environment. The application must outline how the project's activities will impact on regional air quality values as outlined in the Air EPP and the Commonwealth's *National Environment Protection Measure for Ambient Air Quality (1998)* (NEPM Air). The Air EPP and NEPM Air set out long-term objectives for air pollutants and air toxics including hydrocarbons, NO_x, VOCs, BTEX and PAHs. The application must also set out the management practices that are proposed for achieving the desired air-quality objectives.

An EA for petroleum activities has requirements and conditions that the authority holder must comply with to prevent potential impacts on air quality and how greenhouse gas emissions will be minimised. The conditions will set out limits on emissions of air pollutants as well as requirements for monitoring of emissions and ambient air quality, based on information provided in the EA application. The EA will also set out the process that the authority holder must follow to investigate and remedy any reported nuisance. The conditions include:

- restricting the venting and flaring of gas
- listing point sources of fuel burning and combustion facilities, along with emissions limits for various pollutants from these sources and requirements for monitoring of emissions and ambient air quality through an air receiving environment monitoring program (AREMP)
- requiring that petroleum activities must not cause environmental nuisance at a sensitive place (certain public spaces and protected areas), including from dust and odour.

The P&G Act also has requirements to limit gas emissions and there is a mandatory code of practice for leak management, detection and reporting for petroleum production facilities (Queensland Department of Natural Resources and Mines, 2017c). This code of practice is aimed at maintaining appropriate safety standards at production facilities but regular leak detection and repair also minimises atmospheric emissions. However, it should be noted that the frequency of inspection mandated by the Code may be as long as five years (although more frequent inspections may be made if determined appropriate by risk assessment). Hence it is possible that any potential emission sources could go undetected for long periods under such an inspection regime.

The guideline on application requirements for a variation or site-specific EA application for petroleum activities requires that the sources and amount of GHG emissions, as well as steps to mitigate these emissions, must be assessed in a project's EA application. However, there are no conditions related to greenhouse gas emissions in the standard conditions for petroleum exploration or the streamlined model conditions for petroleum activities. The P&G Act requires that any gas produced must be used if commercially feasible, or flared if it is not technically or commercially feasible to use it, or vented if flaring is not technically practicable. These requirements reduce the amount of methane emitted. The codes of practice for petroleum well construction and abandonment (Queensland Department of Natural Resources and Mines, 2016a; 2017a) set requirements for maintaining well integrity throughout the well life cycle, including at abandonment, reducing the possibility of fugitive leaks of methane from wells. These codes are being combined into one code of practice, and will be mandatory as of 1 September 2018.

There is a requirement to report emissions of certain substances to the National Pollutant Inventory (NPI). This is part of the NPI National Environment Protection Measure, a national framework, implemented in Queensland under the EP Regs.

Facilities and corporations that exceed a greenhouse gas emissions threshold must report these emissions to the National Greenhouse and Energy Reporting (NGER) scheme, established by the Commonwealth *National Greenhouse and Energy Reporting Act 2007* (NGER Act). This Act sets out the requirements for reporting the greenhouse emissions and how they are to be measured or calculated. In addition, if a shale gas and oil development exceeds the threshold for the safeguard mechanism under the NGER Act, then they must keep their emissions at or below a baseline set by the Clean Energy Regulator. The P&G Act requires that any gas produced must be used if commercially feasible, or flared if it is not technically or commercially feasible to use it, or vented if flaring is not technically practicable. These requirements reduce the amount of methane emitted.

There is also a requirement to report emissions of certain substances to the National Pollutant Inventory (NPI). This is part of the NPI National Environment Protection Measure, a national framework, implemented in Queensland under the EP Regs. In it, 93 substances have been identified as important due to their possible effect on human health and the environment. These substances include emissions of diesel engines and shale gas and oil activities.

10 Induced seismicity

10.1 Induced seismicity impacts summary

The terms earthquake and seismic event are interchangeable. The term earthquake is often associated with events that are felt or cause damage at the surface, and strictly refers to sudden releases of energy. Seismic events cover events of all sizes. Induced seismicity is an earthquake or seismic event resulting from human activity which is beyond the normal level of historical seismic activity.

The potential for impacts related to induced seismicity due to shale gas and oil projects appears to be low (The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Gibson and Sandiford 2013, Council of Canadian Academies, 2014; Hawke, 2014). The key concerns are:

- induced seismicity resulting from hydraulic fracturing operations
- induced seismicity resulting from reinjection of wastewater.

Induced seismicity directly related to hydraulic fracturing is likely to have very low intensity at the surface and not cause any impact. However, reinjection of wastewater at a large scale may result in more intense seismic events, which may have an impact at the surface (Rubinstein and Mahani 2015).

The potential for induced seismicity impacts related to shale gas and oil projects is well covered in the literature for North America. The mechanisms for these potential impacts will be the same in Queensland. However, the local geological conditions are an important factor (Langenbruch and Zoback, 2016) and this aspect has not been discussed in the literature.

As shale gas and oil resources are typically deeper than CSG resources, the correspondingly higher stresses mean that there is more energy that could potentially be released by induced seismicity. Therefore the potential of hydraulic fracturing to induce seismicity with a magnitude large enough to be felt at the surface is likely to be greater for shale gas and oil than for CSG. Given the low energy levels of hydraulic fracturing induced seismic events, only infrastructure in the immediate vicinity of such an event has the potential to be impacted. The remoteness of Queensland's shale resources means there is minimal local infrastructure that could be affected. There have been no reported induced seismic events in the Queensland CSG projects.

The uncertainty around induced seismicity impacts in shale gas and oil projects in Queensland is primarily in regard to the geological factors. An assessment of the stress regime, the natural seismicity in the area of interest, and the characteristics of faults in shale gas and oil resource regions will help to determine the level of risk. Operational aspects of hydraulic fracturing and wastewater reinjection in any future shale gas and oil projects will also be important in determining the potential for induced seismicity impacts.

The level of risk of these impacts are evaluated as part of risk assessments for hydraulic fracturing and wastewater reinjection operations required as part of an EA application. The risks identified are regulated under the EP Act through conditions on a project's EA. Induced seismicity is not expressly covered under primary or subordinate legislation.

Table 18 Summary of potential induced seismicity impacts of shale gas and oil developments

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Impacts related to hydraulic fracturing												
IS.1	Induced seismicity caused by hydraulic fracturing.	Minor damage to surface infrastructure, nuisance to humans.	Surface infrastructure, amenity.	Low, magnitude of events is small.	Limited to Local.	Seconds.	Inadvertent (for events that can be felt at the surface).	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm.	High. Lack of baseline data on seismicity in Australia, particularly in remote regions.	Low (intensity and frequency).	Greater. Hydraulic fracturing in shale resources applied routinely and at greater depths than CSG.	Moderate. High prevalence of hydraulic fracturing for shale resources.
IS.2	Induced seismicity causing damage to well integrity due to hydraulic fracturing.	Water impacts (see impacts WA.15 to WA.17 in Chapter 4, Table 8).	Groundwater that may be used for other purposes, and supports flora and fauna.	Low, needs a seismic event with enough magnitude to damage casing, well integrity would need to be compromised for impact to materialise.	Limited, single well scale.	Weeks to months (damage lasts longer than seismic event).	Inadvertent. More likely where certain subsurface stress conditions (anisotropic stresses) are present.	EA model conditions – requirements to conduct hydraulic fracturing risk assessment for every well. EP Act general requirement to avoid harm. Code of practice for construction and abandonment of petroleum wells under P&G Regulation.	High. Lack of baseline data on seismicity in Australia, particularly in remote regions.	Low (intensity and frequency).	Greater, as water use for hydraulic fracturing in shale resources likely to be significantly greater than for CSG.	Moderate. High prevalence of hydraulic fracturing for shale resources.
Impacts related to water injection												
IS.3	Induced seismicity caused by fluid injection.	Damage to surface infrastructure, nuisance to humans, changes to surface flow.	Surface infrastructure, amenity, surface water systems.	Low, impacts on surface likely to have low intensity.	Local.	Seconds.	Inadvertent (for events that can be felt at the surface).	EA – site-specific assessment required for sub-surface disposal. EP Act general requirement to avoid harm.	High. Lack of baseline data on seismicity in Australia, particularly in remote regions.	Low (intensity and frequency).	Moderate. High prevalence of hydraulic fracturing for shale resources.	Increased. Depends on depth of reinjection. Wastewater reinjection may be deeper than for CSG, higher stresses.

10.2 Context

Induced seismicity refers to earthquakes that are caused by human activity (National Research Council, 2012; Ellsworth, 2013). Earthquakes are vibrations in the earth caused by sudden movements along fractures or fault planes. The movement is caused by stresses that build up in the subsurface, resulting in failure of the rock creating a new fault or slip on an existing fault surface. Induced seismicity occurs when the subsurface stress regime is altered by anthropogenic activity to the point that an earthquake occurs. The size (amount of energy released) of an earthquake is usually described as its magnitude. There are several different scales used to describe size, with the most common being the Richter scale (denoted as M_L) and the moment magnitude scale (denoted as M_W). These scales are about the same for earthquakes with a magnitude of less than about M_W 7. The magnitude scales are logarithmic, so that an M_W 3 earthquake releases about 100 times more energy than an M_W 1 earthquake. Earthquakes that can be felt at the surface typically have a magnitude of M_W 3 and above, while those that cause damage to buildings generally have a magnitude of over M_W 5, depending on depth. The magnitude can also be negative, and an M_W –2 event releases about 1% of the energy released in an M_W 0 event. Earthquakes with a magnitude of less than M_W 2 are referred to as micro-earthquakes or microseisms.

Magnitude describes the size of an earthquake at its epicentre. The intensity of an earthquake refers to the amount of ground shaking at a specific location. The intensity of an earthquake generally decreases with distance, however, geological conditions also play a role. An M_w 4 event can be easily felt by those close by, but its intensity would be too low to be felt by someone at a distance.

The hydraulic fracturing process is intended to create new fractures or to cause movement/opening of existing fractures. This process produces microseisms (very small earthquakes), mostly with a magnitude of $M_W < 1$ (Warpinski *et al*., 2012; Ellsworth, 2013) and typically between M_W -2 and M_W 0 (Pepper *et al*., 2018). Microseismicity can be detected by microseismic monitoring equipment routinely used to monitor hydraulic fracturing operations. This equipment can routinely detect microseismicity with magnitudes as low as M_W –2. For induced seismicity to have an impact at the surface, it would need to have at least a magnitude high enough for it to be felt. Induced seismicity may have an impact where damage is caused to wells and well casing at depth.

10.3 Impacts

The two main mechanisms by which shale gas and oil developments may result in induced seismicity are:

- hydraulic fracturing operations, which result in an earthquake that is felt or causes damage at the surface
- injection or withdrawal of fluids, which results in changes to the subsurface stress regime, resulting in earthquakes on existing faults.

The potential induced seismicity impacts from shale gas and oil developments are summarised in Table 18.

The intensity of impacts related to induced seismicity will be related to the intensity of induced seismic events at the location of infrastructure or the environmental values that are impacted by these events (Table 18). The scale of impacts will also be related to the magnitude of the induced seismic events, with larger events having impact over a wider area. An earthquake of magnitude M_w 5 will damage structures within a few kilometres. This includes vertical distance, so an earthquake would need to be relatively shallow to cause damage (Gibson and Sandiford, 2013).

10.3.1 Hydraulic fracturing impacts

Potential induced seismicity impacts related to hydraulic fracturing may occur when there is movement along a pre-existing fault surface as a result of hydraulic fracturing operations. This topic has been the subject of numerous studies, and the reviews of shale gas and oil impacts all conclude that the risks of induced seismicity that will be felt or will cause damage at the surface are low (The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014). Warpinski *et al*. (2012) reviewed a comprehensive dataset of microseismic data from across several basins in the US and found no recorded microseismicity with a magnitude greater than M_W 1. They argue that the level of microseismicity is controlled by the geological and stress conditions in the reservoir rather than the parameters of the hydraulic fracturing process. They also found that the maximum magnitude was inversely proportional to depth, with deeper hydraulic fracturing operations producing microseisms with the largest magnitude. These observations suggest that understanding the geological and stress conditions will be important in minimising the potential impacts. There have been some large induced seismic events associated with geothermal projects with magnitudes of between M_W 3 and M_W 4 (McClure and Horne, 2014). It was found that reservoirs with well-developed brittle faults were more likely to have large seismic events, however, the sample size was small. The comparison of geothermal- and shale gas- and oil-related induced seismicity highlights the potential role of the geology as the rock units in the geothermal units are generally stronger than shales and can carry more stress. Temperature and depth are also likely to be important factors. The Council of Canadian Academies (2014) report that 38 seismic events of between M_L 2.2 and M_L 3.8 were observed in the Horn River Basin in Canada between April 2009 and December 2011. These events were interpreted to be associated with existing fault structures.

Induced seismicity may cause damage to wells if the fracture plane that is associated with the microseism intersects the well. An example of this was at the Cuadrilla Preese Hall shale gas well in the UK where an M_W 2.3 seismic event caused damage to the casing (The Royal Society and The Royal Academy of Engineering, 2012). This event was considered to be the result of movement on a fault plane that had not been previously identified. This appears to be an isolated incident.

There have been no reported incidents of induced seismicity related to hydraulic fracturing in Queensland, or from other hydraulic fracturing operations for petroleum resources in Australia (Cook *et al*., 2013; Drummond, 2016). However, there have been seismic events related to hydraulic fracturing at two deep geothermal test sites in SA (Bendall *et al*., 2014). One of these projects in north-west SA recorded several events with magnitudes in the M_W 2 to M_W 3 range. Hydraulic fracturing was conducted in basement rocks that underlie the Cooper Basin, at a depth of over 4,000 m. These basement rocks are associated with a pre-existing fault plane (Bendall *et al*., 2014). The nature of the hydraulic fracturing operation, with very large volumes of fluid, depths, temperatures and the geological environment, is very different to what would be found in shale gas and oil resources. The rocks in shale resources tend to be much weaker and cannot support the stresses needed to generate earthquakes with higher magnitudes (Drummond, 2016).

Although the possibility of induced seismicity related to hydraulic fracturing in Queensland requires further evaluation, the international evidence suggests that the impacts will be minor. The independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory (Pepper *et al.,* 2018) states in this regard: 'The available evidence relating to induced seismic activity from the hydraulic fracturing process is that while low level seismic activity can be associated with hydraulic fracturing, the magnitude of this activity is likely to be very small, with minimal or no damage to surface infrastructure'.

10.3.2 Wastewater fluid injection impacts

The injection of wastewater fluids into the subsurface can change stress conditions, primarily by changing pore pressure thereby reducing confining pressure, which may lead to movement along critically stressed faults. Induced seismicity related to injection of fluids was raised as a potential impact by Cook *et al* (2013) and the Council of Canadian Academies (2014). Ellsworth (2013) found that an increase in the number of earthquakes in the mid-continental US in 2011 and 2012 may have been triggered by nearby wastewater injection wells. They attributed a M_W 5.6 earthquake that destroyed 14 homes and injured two people in central Oklahoma to this cause. Ellsworth (2013) also indicated that the number of events is small when considering that there are over 30,000 wastewater injection wells in the US. Ellsworth (2013) suggested that wells used to dispose of high volumes of water and that may be hydraulically connected to deep basement faults are more problematic.

There is also some uncertainty about what the long-term effects of wastewater reinjection will be within a basin (Cook *et al*., 2013; Council of Canadian Academies, 2014). However, Langenbruch and Zoback (2016) observed in Oklahoma that the frequency of induced seismic events rapidly changes as the rate of wastewater reinjection is increased or decreased.

If wastewater disposal via reinjection was used in Queensland, then induced seismicity impacts may occur as has been observed for example by Langenbruch and Zoback (2016) and (Petersen *et al*., 2017) in some but not all wastewater disposal regions in the US. An assessment of the geological conditions and proposed operational parameters would be required on a case-by-case basis (Cook *et al*., 2013; Hawke, 2014), however forecasting induced seismic hazard is difficult because of the uncertainties in geological data and industrial activity (Petersen *et al*., 2017). The key issues to be addressed include the capacity for targeted geological formations to accommodate large volumes of injected fluids without over-pressurising reservoirs, the stress state in the reservoirs, and the presence and characteristics of faults within and adjacent to the reservoirs. Pepper *et al* (2018) consider that proper management of formation pressures during wastewater injection can mitigate the potential to induce significant seismic events.

10.4 Comparison with coal seam gas projects

10.4.1 Hydraulic fracturing impacts

There have been no induced seismic events related to hydraulic fracturing operations in CSG projects in Australia reported in the literature, nor any detected by the Australian National Seismogram Network operated by Geoscience Australia (Drummond, 2016). Both Drummond (2016) and Gibson and Sandiford (2013) provide an explanation for the low likelihood of induced seismicity that could be felt at the surface during hydraulic fracturing in CSG projects. The strength of coal-bearing formations is low compared to other rock types as they can only support low stresses. Stresses increase with depth and are relatively low at the depths of CSG resources (200 to 1200 m), which limits the magnitude of earthquakes that can occur in CSG developments due to hydraulic fracturing.

The generally greater depths and higher rock strengths of shale gas and oil resources mean that induced seismicity associated with hydraulic fracturing may have higher magnitudes than would be expected from CSG projects. The increased frequency and intensity of hydraulic fracturing operations also means that induced seismicity could occur more often. As discussed previously, any such seismicity is still likely to have small magnitudes and impacts will have low intensity.

10.4.2 Fluid injection impacts

The use of reinjection to dispose of wastewater has had limited application in Australia. The largest reinjection operation in Queensland involves the reinjection of treated produced CSG water into the Precipice Sandstone at Australia Pacific LNG's Reedy Creek Site in the Surat Basin. This facility has a designed capacity of 40 ML/day and 12 injection bores, handling the produced water for nearly 500 CSG wells. The treated water is injected into the Precipice Sandstone, at approximately 1300 m depth, with over 10,000 ML injected since early 2015. No seismicity has been reported in association with this reinjection project.

The potential for induced seismicity related to wastewater reinjection for Shale Gas and Oil will depend on the depth and nature of the target formations for reinjection. The risk of seismicity will be reduced for areas where the produced water is being reinjected into aquifers that have had their water levels reduced. The potential induced seismicity impacts need to be assessed on a case-by-case basis.

10.5 Relevant regulations

Induced seismicity impacts related to hydraulic fracturing in Queensland are regulated under the EP Act through the EA process. EAs for petroleum activities require a risk assessment to be conducted if hydraulic fracturing activities are to be conducted under the authority. This risk assessment must consider a wide range of factors, including those related to induced seismicity. The seismic history of the region, along with the practices and procedures to ensure that the stimulation activities are designed to be contained within the target gas producing formation must be considered in order to inform the risk of induced seismicity. An EA will also require that written stimulation management procedures be prepared that include information on the risk of induced seismicity.

Several major reviews on the impacts of hydraulic fracturing and the shale gas and oil industry have recommended a 'traffic light system' for reducing the risks of induced seismicity during hydraulic fracturing operations (The Royal Society and The Royal Academy of Engineering, 2012; Cook *et al*., 2013; Council of Canadian Academies, 2014; Hawke, 2014). This system would place thresholds on the maximum magnitude of microseismic events measured in real time during hydraulic fracturing. As the first threshold is crossed (amber), hydraulic fracturing proceeds but with a heightened level of care. Once the red threshold is crossed, hydraulic fracturing operations would cease and pressures would be allowed to drop to either slow or stop the progress of fracturing.

The P&G Act and the code of practice for the construction and abandonment of petroleum wells requires that they be constructed to maintain well integrity throughout the lifecycle. This includes during hydraulic fracturing activities.

Induced seismicity impacts related to wastewater reinjection in Queensland are also managed through the EA process. The *Guideline for application requirements for petroleum activities* under the EP Act states that an application for an EA where reinjection of treated produced CSG water into an aquifer is planned must be made in a staged approach so that the feasibility of reinjection can be evaluated. The information required in this process focuses on protecting the aquifer and also includes a requirement for information on the potential for induced seismicity due to the injection program. These requirements are specific to treated produced CSG water. Management of produced water from shale gas and oil resources would be considered under the requirements for the management of waste.

11 Other industries

11.1 Impacts on other industries summary

The potential impacts on other industries from shale gas and oil projects will be similar to those seen in relation to the CSG sector. The agricultural sector has the highest likelihood of being affected because it is the dominant industry in areas prospective for shale gas and oil. There will be some variations on impacts based on the local land uses and other coexisting industries. The key concerns are:

- degradation of the natural resource base (primarily the soil and water) on which agriculture depends
- decreased productivity from agriculture due to loss of productive areas for shale gas and oil infrastructure and dust contamination
- economic impacts such as competition for labour and other resources, and changes to land values
- increased demands on local infrastructure (roads, utilities)
- damage to the tourism brand and visual amenity in rural areas.

Potential impacts on other industries may also be positive, through increases in economic activity and provision of better infrastructure.

The potential impacts of conventional and unconventional petroleum resource development on other industries is an area of active research that is often linked with research into the social impacts on these industries. The CSG sector in Queensland is a good example of this interaction in a rural environment. In contrast, the potential impacts in remote areas of Queensland, with arid environments and limited infrastructure, are not covered in the literature.

The uncertainty around the impacts of shale gas and oil developments on other industries are related to uncertainty around the scale of development of shale gas and oil and the interactions with industries in the areas prospective for shale gas and oil. For example, there is uncertainty around the impacts in western Queensland (e.g. Cooper Basin, Georgina Basin) on grazing activities. The soils in these semi-arid to arid regions are fragile and may need careful management to allow grazing and shale gas and oil developments to coexist. Another area of uncertainty is the interaction of different socioeconomic impacts at the local and regional scale.

The interaction of the shale gas and oil developments with other landholders is regulated under P&G Act and the MERCP Act. Access rights for authority holders are granted under the P&G Act for petroleum resources, however the Land Access Code made under the MERCP Act (Queensland Department of Natural Resources and Mines, 2016b) sets out how these rights should be exercised. In addition, the impacts on other land users must be considered, managed and minimised as a requirement of an EA application. Regulation pertaining to impacts on the natural resource base for agriculture have been covered in the discussion on surface water and groundwater resources (Chapter 4) and land (Chapter 6) impacts. Impacts related to other industries such as tourism may be considered under a range of regulatory frameworks, including under RPI Act, NC Act, Heritage Act, ACH Act and the SDPWO Act.

A summary of the potential impacts of shale gas and oil developments on other industries is provided in Table 19.

Table 19 Summary of potential impacts of shale gas and oil developments on other industries

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
Impacts related to shale gas and oil operations												
OT.1	Vehicle traffic, well pad construction.	Compaction of soil leading to decreased productivity.	Agricultural land.	Low to medium. Location specific, depends on soil's ability to recover.	Limited to the area of activity (access tracks, well pads).	Years. Location specific, depends on soil's ability to recover.	High.	EA model conditions – specific requirements for protection of land values and for rehabilitation. EP Act general requirement to avoid harm. Land Access Code, MERCP Act RPI Act.	Medium.	Low (intensity, scale).	Less. Shale resources likely to have a smaller surface footprint with multi well pads.	Low. Regulation of impacts on land in multiple sectors
OT.2	Taking of water (surface water and/or groundwater resources) by shale resource developers.	Loss of access to water for agriculture and other industries, changes to water quality.	Water resources used for agriculture.	Low. Relative volumes used by shale resource development low compared to agricultural uses.	Local.	Years.	Low. Depends on nature of agricultural activities.	Water Act applies to extraction of water from the environment. Make good obligations under Chapter 3 of the Water Act RPI Act also protects water resources. EA model conditions – requirements to protect water values. Environmental Protection (Water) Policy. EP Act general requirement to avoid harm.	Low.	Low (intensity, scale).	Less. Shale resources likely to use/impact less on water resources overall.	Low. Regulation of water extraction in multiple sectors
OT.3	Infrastructure development (well pads and access tracks).	Loss of productive land.	Agricultural land.	Medium.	Local to regional.	Years to decades.	High.	EA model conditions – specific requirements for rehabilitation. EP Act general requirement to avoid harm. Land Access Code, MERCP Act RPI Act.	Low.	Low (intensity, scale).	Similar to lesser, depending on well pad configuration.	Low. Regulation of land access in multiple resource sectors.
OT.4	Vehicle traffic.	Dust contaminating agricultural land, impacts on farming practices.	Agricultural land.	Low.	Limited.	Years.	High. Dirt roads commonly used.	EA model conditions – requirements to limit erosion includes wind erosion. EP Air Policy limits dust emissions. Environmental Protection Policy Environmental Nuisance applies to dust. EP Act general requirement to avoid harm. Land Access Code, MERCP Act.	Low.	Low (intensity, scale).	Increased, more truck movements for shale resources.	Low. Regulation of water extraction in multiple sectors
OT.5	Access by vehicles introducing invasive species.	Loss of productivity, increased management costs.	Agricultural land.	Medium.	Local.	Years.	Inadvertent.	Land Access Code, MERCP Act Biosecurity Act Weed management plans. P&G Reg requires prevention of the spread of weeds.	Low.	Medium (intensity).	Similar.	Low. Regulation weeds in multiple sectors (resources and agriculture)
OT.6	Intrusion of shale gas and oil activities onto rural land.	Changes to property value due to reduction in farmable land.	Economic value.	Medium.	Local.	Years.	Low.	Land Access Code, MERCP Act (compensation agreements).	High.	Low (intensity, scale).	Similar.	Low. Regulation of land access in multiple resource sectors.
Other socioeconomic impacts												
OT.7	Change in rural landscape.	Reduced tourism due to loss of amenity.	Economic value	Low. Very location specific	Local.	Years.	Low, only in areas with tourism.	Considered in Social Impact Statements as part of EIS process.	Medium.	Low (intensity).	Similar	Low. Regulated through EIS. Coordinated projects process.
OT.8	Demand for local labour.	Increased labour costs for other industries.	Economic value	Low.	Local.	Months to years.	Low, only in areas with high enough local population otherwise workers will commute.	Considered in Social Impact Statements as part of EIS process. Strong and Sustainable Resource Communities Bill may be relevant.	Medium.	Low (intensity).	Similar	Medium. Issue in other resource developments.

	Impact Mode	Potential impact	Environmental value impacted	Intensity	Scale	Duration	Frequency	Relevant regulations	Uncertainty	Materiality (impact rating)	Relative to CSG	Requirement for regulatory focus
OT.9	Indirect employment.	Increased labour costs for other industries.	Economic value	Low.	Local.	Months to years.	Low, only in areas with high enough local population otherwise workers will commute.	EIS process considers social impacts. Strong and Sustainable Resource Communities Act may be relevant.	Medium.	Low (intensity).	Similar	Medium. Issue in other resource developments.
OT.10	Access to land.	Changed land values.	Economic value	Low.	Local.	Years.	Low, only in regions with land with amenity value.	EIS process considers social impacts. RPI Act.	Medium.	Low (intensity).	Similar	Low. Regulated through EIS. Coordinated projects process.
OT.11	Activity on aboriginal lands	Decreased access to traditional lands	Cultural value	Low to medium.	Local	Years	Low, dependent on location.	EIS process considers social impacts. ACH Act. ILUA's under NT Act (Cwlth).	Medium	Moderate.	Varies dependent on location.	Medium. Issue in other resource developments.

11.2 Context

As with all industries, shale gas and oil developments will have the potential to impact on other industries within its sphere of influence. This may include direct impacts in terms of competition for resources (including labour and materials) through to broader macroeconomic impacts. These impacts have been considered, based heavily on the CSG experience in Queensland, and as such the comparison between CSG projects and shale gas and oil projects is embedded in the discussion of the impacts rather than being considered separately.

Agriculture is the dominant industry in the regions prospective for shale gas and oil in Queensland. Potential impacts specific to agriculture are considered in Section 11.3, whereas impacts on other sectors are discussed in Section 11.4.

11.3 Impacts on agriculture

Resource developments such as CSG or shale gas and oil are typically undertaken in rural areas, and much of these areas are used for agricultural production. These developments can impact upon agriculture in a variety of ways. Two of these impacts are considered:

- impacts on the farm natural resource base
- impacts on the farm enterprise.

11.3.1 The farm natural resource base

The natural resource base refers to the natural resources that agriculture relies upon. These resources include the soil, water and vegetation. Agriculture can be impacted when other industries degrade this natural resource base. The potential impacts of shale gas and oil projects discussed in this report on surface water and groundwater resources (Chapter 4), land (Chapter 5), vegetation and fauna (Chapter 8) and air quality (Chapter 9) could all lead to impacts on the natural resource base used by agriculture. The following discussion describes these impacts from the perspective of agriculture.

Soil resources

Studies into the impact of CSG development on agricultural soils have highlighted the risk of soil damage such as compaction, sub-soil mixing, contamination or accelerated erosion losses (Antille *et al.*, 2014). CSG operations can cause soil compaction when heavy machinery is used in the installation or maintenance of wells, pipelines or other infrastructure. The movement of heavy machinery can compress soils, resulting in a reduction of soil pore space, which increases soil density, decreases infiltration and water flow, and reduces root growth (see Figure 30). Most damage due to compaction is restricted to within the development footprint for pipelines and well lease areas. As a result, impacts via soil compaction are likely and will be constrained to approximately 1% to 2% of the agricultural area.

Studies on CSG leases on the Darling Downs have found that in damaged soils the soil bulk density is higher, infiltration rates are lower, and soil penetration resistance is higher than on surrounding agricultural fields (Antille *et al.*, 2014). Similar rates of soil damage have been shown to result in crop losses of approximately 43% in the first year after compaction with more than five years required for rehabilitation of damage via natural processes (Radford *et al.*, 2001). Yield reductions have been observed on and around pipelines in China and these have been observed to persist for over eight years (Shi *et al.*, 2015).

The use of directional drilling and a subsequent reduction in the number of well pads in shale gas and oil projects relative to CSG is likely to result in a smaller footprint per well, and thus a lower impact on soil compaction. The intensity of these impacts will also be dependent on the prior land use and the nature of the soils in the impacted area.

The dominant land use in Queensland is grazing, particularly in western Queensland (see Section 1.2.3 and Figure 6) and the impacts on grazing land may be different to those on cropping land. The soils in arid regions may be more fragile than those in areas with higher rainfall and may take longer to recover from damage. Damage to soils in these areas may reduce the livestock carrying capacity. Wind erosion can become a serious threat. Erosion in these environments due to overgrazing is a well-known problem (e.g. Queensland Department of Environment and Resource Management, 2011; Silburn *et al*., 2011). The impacts of intensive shale gas and oil development in arid and semi-arid regions on grazing lands are not well represented in literature.

The cumulative impacts of multiple land users need to be taken into consideration (Cook *et al.*, 2013). Cook *et al*. (2013) also point out that the impacts of shale gas and oil developments in more remote communities may vary to those in the CSG sector because of the nature of the land use in those areas.

Surface water and groundwater resources

Water resources are another important part of the agricultural natural resource base. As discussed in Section 4.3.1, shale gas and oil activities require significant volumes of water. The sourcing of water could have impacts on local surface water and groundwater resources. Loss of access to water for farmers would have a significant impact on the productivity and profitability of local water users, whether for grazing, irrigation, or access to water in the environment for dryland agriculture.

Agriculture is Queensland's primary water user, accounting for approximately two-thirds of the state's water consumption (see Section 2.5.2). While the amount of water consumed by agriculture across Queensland is several orders of magnitude greater than the amount of water estimated for water use in the shale gas and oil projects (see Section 2.3), local impacts may be significant if there is competition for the same water resource. In the Surat CMA, the CSG sector extracts around 65,000 ML/year, while water bores in the Surat CMA extract about 203,000 ML/year for non-CSG uses, primarily agricultural (Office of Groundwater Impact Assessment, 2016). The *Underground water impact report for the Surat Cumulative Management Area* has identified that around 2% of the 22,500 water bores in the area are predicted to be impacted to the extent that the water supply may be impaired (Office of Groundwater Impact Assessment, 2016).

Authority holders are obligated under the Water Act to 'make good' the impact (see Section 4.5.1). The potential impacts of shale gas and oil on water resources used by agriculture will be location dependent, however, these impacts are expected to be less than those for CSG (as outline in Section 4.3.1 and Section 4.4.1). Beneficial use of flowback and produced water for agriculture may reduce any impacts on water use due to shale gas and oil projects.

In addition to impacts on water quantity, water quality is also an important issue. Contamination of agricultural land and water supplies may also impact on the agricultural industry. See Section 4.3.2 for a more detailed discussion on the potential for water contamination due to shale gas and oil projects.

Invasive species

Construction and activities at well pads could facilitate the dispersal of invasive species by altering existing habitat conditions, stressing or removing native species, and allowing easier transport of seed/plants by increased traffic and equipment movements. These issues have been discussed in many studies (Cook *et al.*, 2013; Council of Canadian Academies, 2014; Ponce Reyes *et al.*, 2014; New York State Department of Environmental Conservation, 2015b). Invasive species may have an impact on agriculture production and profitability through competition and increased costs associated with the use of control measures (e.g. herbicides).

Figure 30 (left) Workover rig operating on farmland near Chinchilla, Queensland. (right) Surface soil compaction evident after operation of workover rig shown left

11.3.2 The farm enterprise

Resource industries such as CSG and shale gas and oil are likely to impact on farming and farm operations due to the nature of these developments, which includes the placement of infrastructure within farms and the traffic required to access this infrastructure.

Reduction of farming area may occur as infrastructure may sometimes be placed within productive areas within the farm. This could result in loss of productive area for the farm. The total effective loss of productive area is the product of the area of the resource development footprint and the relative loss of production within that area. For CSG, the area of the resource development footprint is relatively low. For example, the total footprint for CSG within a case study area with intensive development west of Chinchilla was found to be approximately 8% (Marinoni and Navarro Garcia, 2016). However, a significant portion of this footprint was due to operations concentrated around the water and gas processing plants. For most farming operations within the resource development area, the main contribution to loss of productive area will come from infrastructure such as pipelines, well pads, set down yards and access yards. An economic analysis of the impacts to production areas west of Chinchilla due to CSG have estimated that the revenue losses in grazing regions ranged between $1,400 and $3,000 per well (Marinoni and Navarro Garcia, 2016). These monetary values do not take into account compensation paid to landholders.

Increased dust has been cited by farmers as an issue affecting their perceptions of coexistence with a resource development (Huth *et al.*, 2014). Studies of the effects of dust on agricultural systems are rare, however, studies have been undertaken on the effects of dust on plant growth (McCrea, 1984; Armbrust, 1986), energy and water balance (Anda, 1987), pesticide emissions (Leys *et al.*, 1998), pollination (McCrea, 1984; Anda, 1987), downgrading of produce (McCrea, 1984), and impacts on animals such as disease or excessive teeth wear from consuming dust during foraging (McCrea, 1984). As of April 2017, no study has quantified the effect of dust from CSG, or shale gas and oil, on agricultural production systems in Australia despite it being raised regularly as an important issue by farmers. Dust emissions from resource developments are largely due to increased traffic volumes. Research shows that dust emissions are directly related to the number, size and speed of vehicles, all else being equal (Gillies *et al.*, 2005). Resource development significantly increases the number of vehicles such that increased truck traffic has been rated as the most significant social or environmental concern in a study of a US shale gas area (Theodori, 2009). Whilst farm access agreements have covered the need for reduced vehicular speeds on farms, the impact of high speed trucks on public rural roads has been mentioned by landholders, as have impacts of dust on crops, stock and farm workers (Huth *et al.*, 2014). It is estimated that the number of heavy vehicle movements is likely to be higher for shale gas and oil projects (Cook *et al.*, 2013; New York State

Department of Environmental Conservation, 2015b) than for CSG (given the greater number of wells on a pad and need for hydraulic fracturing) and therefore the potential for impacts of dust on farm enterprises are likely to be higher, but confined for fewer tracks than CSG.

The local agricultural economy may also be impacted. These impacts are considered along with social and economic impacts in Section 11.4. The economic impacts of shale gas development on property prices is an area of ongoing research. As of April 2017, the results are mixed: there is evidence of both positive and negative effects on property prices, depending on diverse factors including potential effects on water sources and the nature of compensation payments to landholders (Muehlenbachs, Spiller and Timmins, 2015).

11.4 Impacts on other sectors

The impacts of the shale gas and oil industry on other sectors (impacts OT.7 to OT.10 in Table 19) involve macroeconomic impacts occurring at the national scale and project-specific impacts occurring at the local to regional scale. For the macroeconomic impacts, the effect of a shale gas or oil export sector is similar to any other large energy export sector. For the local to regional impacts, there are likely to be strong similarities with CSG. Experience has shown that developing unconventional gas in regions with pre-existing industries can lead to conflict. Conflict may take the form of outright rejection, or more likely, disagreements over the terms of coexistence. This may be particularly difficult in communities that have not previously had exposure to the resources sector and where new arrangements required between existing industries and the new energy extraction industry are perceived as unfair. This can cause substantial tension, social conflict and legal challenges (Perry, 2012; Sherval and Hardiman, 2014; Turton, 2015). Cook *et al* (2013) discuss these socioeconomic issues, particularly in regard to the issue of social licence to operate, but do not discuss the impacts on other industries. The Canadian Council of Academies (2014) and Hawke (2014) do not consider these issues in any detail.

11.4.1 Macroeconomic impacts

As noted in a review of shale energy in South Africa, a shale energy export industry has potential to contribute to the pre-existing macroeconomic impacts (both positive and negative) associated with existing energy export industries (van Zyl *et al.*, 2016). Positive impacts include increases in real gross domestic product (GDP), improved balance of payments, employment, household incomes and tax revenues. Negative macroeconomic impacts identified by van Zyl *et al* (2016) are related to the uncertainty in the size of the benefits to the broader economy and the implications for macroeconomic policy. Improved balance of payments may also put upward pressure on exchange rates. These macroeconomic impacts are not restricted to the shale gas and oil industry; they apply to any energy export sector, and the development of a shale gas and oil industry at scale would likely add to the macroeconomic impacts from forms of existing energy exports, for example, conventional gas and CSG (Reeson, Measham and Hosking, 2012; Johnson and Boersma, 2013; Simshauser and Nelson, 2015).

11.4.2 Tourism

Aside from the macroeconomic impacts described above, there are also potential impacts on tourism. In terms of local and regional impacts, most locations where the tourism sector is a major part of the economy tend to have planning restrictions or regulations that would impede the extraction of gas and petroleum within the main tourism area. In Queensland, the most prominent example of this is the Commonwealth's *Great Barrier Reef Marine Park Act 1975*, which prohibits the extraction of oil and gas within the area (Olsson, Folke and Hughes, 2008). In areas where tourism plays a secondary role, some concerns for potential negative effects have been raised, including the potential to negatively impact the tourism brand and visual amenity of rural areas where shale gas is being developed (Rumbach, 2011; Barth, 2013; Jenner and Lamadrid, 2013). This topic has not received much research attention and there are few studies providing strong evidence of these effects. Studies have demonstrated, however, that drilling activity involves temporary workforces that utilise hotel accommodation. Although this serves to increase occupancy rates for those accommodation providers, it reduces availability of accommodation to other visitors engaged in tourism and recreation (Jacquet and Stedman, 2013).

Demand for labour

11.4.3 Direct employment

In locations where shale gas and oil are established as new industries, demand for labour usually exceeds local supply very quickly. This has the effect of increasing wage prices, which can draw labour forces from other sectors (such as agriculture) and from beyond the region. The demand for labour is particularly strong for certain types of experience and skills and tends to attract male-dominated workforces from far beyond the region. These effects often lead to substantial disparities in local incomes between those working in energy extraction and those in other sectors. It may also lead to a shortage of labour in other sectors such as agriculture for any job type with transferrable skills (e.g. machinery operators, mechanics). It should be noted that not all shale energy employees reside in the region where the industry takes place (sometimes very few), with others commuting from beyond the region (fly-in fly-out (FIFO) and drive-in drive-out (DIDO)). Compared to some fossil fuel projects such as coal mining and oil shale that generally require large open-cut mines, shale gas involves many wells drilled across the landscape. This has important implications for direct labour supply in communities as the size of the drilling workforce can increase or decrease as the demand for energy fluctuates or as drilling operations move from region to region (Measham and Fleming, 2014).

11.4.4 Indirect employment

Staff on relatively high incomes living within the local region where energy development is taking place inject some of their money into the local economy by purchasing local goods and services. This leads to job ‘spill-overs’ or indirect employment and increased income in the local service economy. These spill-overs can attract additional new people to the region and have a compounding effect on demand (Measham, Fleming and Schandl, 2016). Increases in activity in the construction sector, accommodation services and hospitality are common developments. These local economic benefits are strongest in the early period of the industry’s establishment and are likely to reduce over time. Regions with long-term involvement in the energy sector may see the effects of declining levels of income over several decades (Haggerty *et al.*, 2014; Chapman, Plummer and Tonts, 2015) as labour supply adjusts to meet demand.

Labour crowding-out generated by labour demand in resource extraction industries can affect regional economic growth by weakening competitiveness in the tradable goods sectors. The higher costs of production (given the likely increase in local wages generated by labour demand) hastens the shutdown – or size reduction – of firms whose products (manufactured goods, food and similar) can be imported from somewhere else at cheaper prices (Fleming, Measham and Paredes, 2015). To reduce this effect, governance arrangements can encourage local supply chains for inputs wherever this is feasible as a means of supporting wider community benefits from energy booms (Warhurst, 2001). In the case of tradable goods the forward and backward linkages can have positive effects if regions have the capacity to maintain and expand local firms that specialise in dealing with inputs and/or outputs of extractive industries. Thus, if forward or backward linkages occur, job spill-over can be positive for the tradable goods sectors, netting or overriding labour crowding-out potentially happening in other manufacturing firms (Fleming and Measham, 2015).

11.4.5 Access to land

Unconventional gas extraction involves the access to land used for other economic activity, and has potential to reduce the market value of surrounding land in some circumstances (Obeng-Odoom, 2014). In some cases shale gas and oil infrastructure can coexist with other land uses (well pads in grazing areas) while others cannot (a large water treatment facility). Unlike mines, which tend to have a relatively small but intense spatial footprint, shale gas (along with CSG) tends to be spread out across a wider area (lower intensity activities over thousands of square kilometres), which means there are potentially more impacted parties for the purposes of compensation, and potentially more diverse impacts due to drilling, pipelines, vehicle movements, and water impacts (Jacquet, 2012; Stedman *et al.*, 2012).

11.4.6 Demand for new infrastructure and services

A common effect of a boom in resource-led regional development is increased housing costs as supply changes and struggles to keep up with demand for housing by new residents (Haslam McKenzie and Rowley, 2013; Ennis, Tofa and Finlayson, 2014), especially in highly deregulated housing markets. This issue may be particularly acute for local tenants who have not benefited from the direct income benefits associated with the resource boom. This in turn may cause outward migration of local residents, especially those from lower income households, single parent families and elderly people. Income inequality and poverty can increase for the same reasons: rising property and rental costs increase the cost of living for everybody, but not all the local population is benefiting from higher incomes (Fernando and Cooley, 2016; Measham, Fleming and Schandl, 2016).

11.4.7 Interactions between impacts

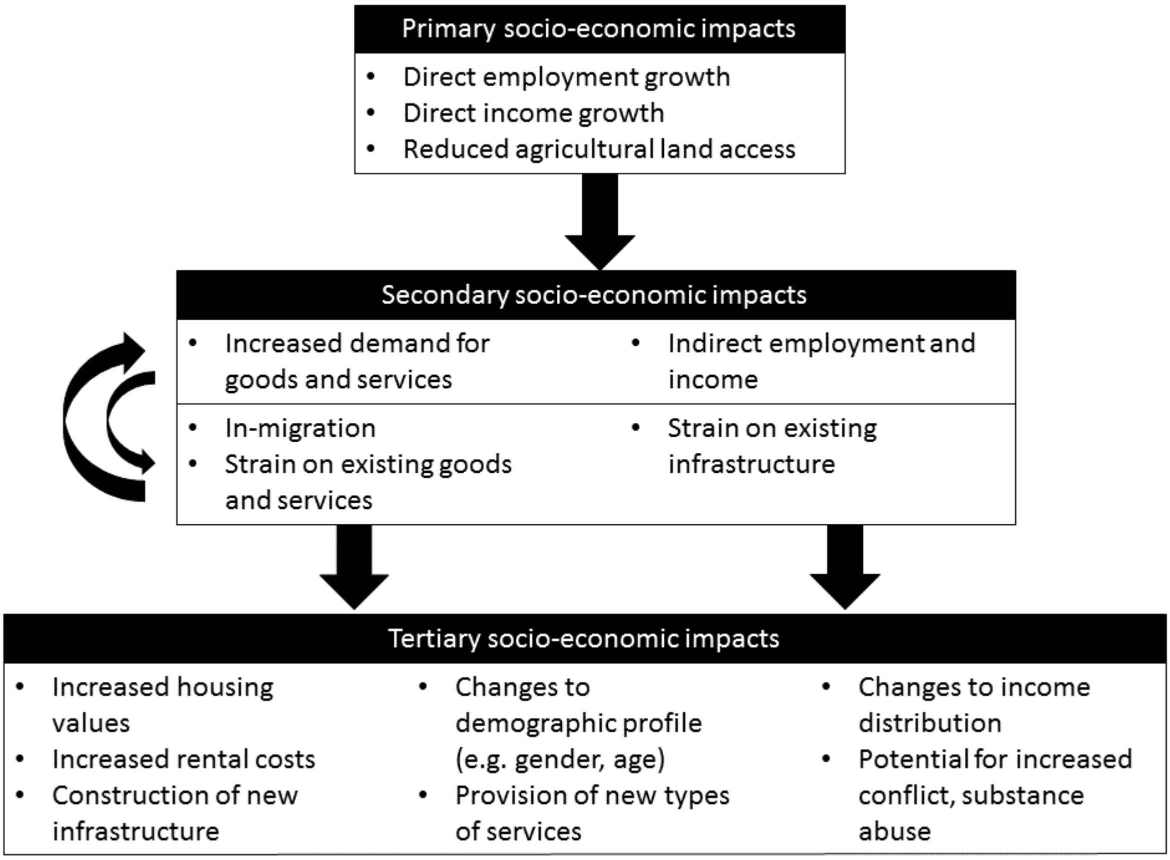
The regional (i.e. non macro) socioeconomic impacts on other sectors are presented in the previous sections in isolation. However, it is important to recognise there are interactions between these impacts. For example, the number of direct jobs has flow-on implications for indirect jobs. Inward migration to fill these jobs has implications for services. These interactions are summarised in Figure 31 as a series of flow-on effects.

11.4.8 Aboriginal land

The NT HF Inquiry (Pepper *et al*., 2018) discuss the impacts of shale gas and oil development on Aboriginal people and their culture at length. They note that the impacts may extend beyond concerns about areas that meet a legal definition of a 'sacred site' that are protected under legislation. Concerns extend to the impacts of the incremental encroachment of industry on to land that aboriginal people see as traditional country and how that affects access and the ability to pass on traditional knowledge. There are also concerns about timeframes for the approval process exacerbating stress for aboriginal communities.

Cook *et al*. (2013) provide a discussion on the likelihood that shale gas and oil projects in western Queensland will be on aboriginal land. They suggest that 'it is likely that a significant amount of exploration and development will be on lands over which Native Title has either been recognised or is subject to a claim, pursuant to the *Native Title Act 1993*'. The Commonwealth's *Native Title Act 1993* (NT Act), deems native title to have been extinguished if the land is under freehold title, but can be claimed over vacant Crown Land, other public lands, and some types of leases (such as pastoral leases). Cook *et al* (2013) suggest that most shale gas and oil authorities would be likely to include some land potentially subject to native title.

The NT Act gives only limited rights to native title holders. Native title holders do not own rights to subsurface resources, nor do they have exclusive use rights or right of veto over development. Native title holders have the legal right to negotiate an Indigenous Land Use Agreement (ILUA). ILUAs are usually negotiated between the relevant parties, although a court determination may be required if agreement cannot be reached. There are no restrictions on the considerations of an ILUA, but they may include agreement regarding financial compensation, employment opportunities, cultural heritage preservation, environmental preservation and consent from the titleholders for possible future activities. While this is Commonwealth legislation, the Queensland Government coordinates the process for authority holders. The Queensland Government provides guidelines for dealing with native titles.



Source: Measham *et al.*, 2016

Figure 31 Primary, secondary and tertiary impacts of resource development on host communities

11.5 Regulations

The interaction of the shale gas and oil developments with other landholders is regulated under a range of regulatory instruments:

- the P&G Act grants land access to authority holders for petroleum resource
- the Land Access Code (Queensland Department of Natural Resources and Mines, 2016b) made under the MERCP Act sets out how access rights should be exercised to reduce impacts on a landholder's activities. This code:

‘ (a) states best practice guidelines for communication between the holders of resource authorities and owners and occupiers of land, public land authorities and public road authorities; and

(b) imposes on resource authorities mandatory conditions concerning the conduct of authorised activities on land.’

By negotiation, the authority holder and landholder can work together to reduce the impacts of development.

- an EA for petroleum activities also requires that potential impacts on other land users must also be considered, managed and minimised. Indirect socioeconomic impacts discussed above are considered as part of the environmental impact statement process for a site-specific EA application
- regulatory controls regarding impacts on other environmental values such as surface water and groundwater resources (Section 4.5), contamination of soil and erosion (Section 5.5) will also reduce any potential impacts on agricultural users of the natural resource base
- the RPI Act identifies and protects areas of Queensland that are of regional interest and resolves potential land use conflicts and protects Priority Living Areas, Priority Agricultural Areas, Strategic Cropping Area and high-quality agricultural areas from dislocation, strategic cropping land, and Strategic Environmental Areas. Development is permissible in these areas as long as existing land uses are protected
- State (ACH Act) and Commonwealth (NT Act) legislation regulate potential impacts on aboriginal people and sites of cultural significance. The NT Act allows authority applicants and registered and determined native title parties to make ILUAs about how land and waters in the agreement area will be used and managed in the future. Social impacts on aboriginal communities are considered as part of a social impacts statement.

Impacts related to invasive species are regulated under the Biosecurity Act. The Land Access Code also has requirements for managing risks around declared pests. Regulation relevant to impacts on the natural resource base for agriculture have been covered in the discussion of water (Chapter 4) and land (Chapter 5) impacts.

Impacts related to other industries such as tourism may be considered under a range of regulatory frameworks, including under the RPI Act, NC Act, *Heritage Act 1992*, ACH Act and SDPWO Act for a ‘coordinated project’. The circumstances that would trigger any of these Acts would be fairly unique to the particular location.

12 Conclusions

This review assesses the current scientific knowledge of the potential environmental impacts of the development of shale gas and oil resources in Queensland, including impacts to agriculture and tourism. This chapter outlines the main findings of this assessment. The current state of knowledge of the potential impacts of shale gas and oil is discussed. This is followed by a summary of shale gas and oil activities and technologies, and their similarities to, and differences from, those used in other gas and oil resource developments in Queensland, including CSG. The potential impacts identified in this review are then summarised and compared with those for other gas and oil resources. Finally, an overview of the regulatory framework that applies to shale gas and oil development is presented, along with a summary of the impacts that may require a higher degree of regulatory focus.

12.1 State of knowledge

There is a growing body of literature on shale gas and oil impacts, particularly national-scale reviews from countries where either shale gas and oil or more generally unconventional gas industries are further developed than in Australia. The main reviews used throughout this report were from Australia, the US, the United Kingdom and other parts of Europe, and Canada. An increasing number of Australian reviews and inquiries are available that either focus on specific regions (such as New South Wales, South Australia or the Northern Territory) or on specific segments that may be impacted (such as water resources or public health). Many of the reviews seek to generalise broad findings across multiple resource development areas; the geology, geography, populations, ecosystems, hydrology, hydrogeology and land systems vary greatly in these areas. As a result of this variability, the degree to which broad-scale regional assessments can predict impacts in a specific state such as Queensland is uncertain.

The technology that will be applied to the development of Queensland's shale gas and oil industry is likely to draw significantly on experiences in North America. The US shale gas and oil industry is a well-established industry with a 40-year track record of developing resources at scale. The US industry has been made possible by rapid advances in hydraulic fracturing and drilling technologies, which allow unconventional resources to be developed.

The hazards and impact modes that arise from shale gas and oil activities in North America are well documented in the literature. Many of the activities, and therefore the associated hazards, already occur in Queensland in the development of other gas and oil resources. This knowledge can be applied to assessing the hazards that are likely to be present in the development of Queensland's shale gas and oil resources. There is less certainty about the impacts that may result, because this requires an assessment of both the hazards and the environmental, economic and social values that may be impacted.

Shale gas and oil development is still at an early stage in Queensland, and there is significant resource potential across the state. Research is still needed to understand these resources and the specific environmental, economic and social values with which they will interact during their development. All major studies agree that there is a need to collect baseline environmental data on regions that are prospective for shale gas and oil to understand the environmental values ahead of development. This research will allow the existing resources and potential impacts to be better understood, and will inform the assessment of risks and the design of risk treatments to effectively avoid, mitigate or manage impacts.

Impacts specific to the Queensland context, or arid environments similar to the areas in Queensland where prospective shale gas and oil resources are located, are not as strongly represented in the literature.

Cumulative impacts were considered out of scope for many of the major reviews of unconventional gas. This was mostly due to the lack of appropriate baseline monitoring in major shale gas developments overseas from which conclusions on cumulative impacts could be drawn. Hence, there is emphasis for many of these studies on baseline conditions and ongoing monitoring as an important area for future research in prospective shale gas and oil regions.

12.2 Comparison with other oil and gas activities

At the most basic level, shale gas and oil development is just like any other gas and oil development, in that it involves the drilling of wells to extract gas and oil from the subsurface. Many of the activities are common across the sector. However, there are also some important differences that are related to the characteristics of shale resources.

12.2.1 Key similarities

The following technologies for shale gas and oil development have already been used in Australia and, specifically, Queensland:

- drilling technologies, including horizontal sections – these are very much the same as those used for deep conventional oil resources
- hydraulic fracturing, which is used for CSG in Queensland, it has also been used extensively for unconventional petroleum resource (mostly tight gas) development in South Australia and the Northern Territory. Several exploratory wells for unconventional resources in Queensland, including shale gas and oil, have been hydraulically fractured.

Drilling fluids, hydraulic fracturing fluids and requirements for well pads and associated infrastructure are anticipated to be similar to those used in existing conventional petroleum and CSG wells.

Similarities in the technologies mean that there will be similarities in potential impacts at a well scale.

The scale of development for shale gas and oil and CSG development may be similar; they both target reservoirs that are laterally extensive and have low permeabilities, which require a large number of wells to access the resource. The overall project life cycle will also be similar.

Many of the activities in shale gas development are generic to other petroleum resource or industrial developments. The impacts of these activities are fairly well known and managed under existing mechanisms. Many of these aspects get little discussion in the literature on shale gas and oil impacts. Examples are:

- resource exploration
- site preparation
- use of heavy equipment
- increased traffic volumes
- gas/oil processing
- air emissions
- waste management
- noise and effects on amenity

- land erosion
- contamination and effects on biodiversity.

12.2.2 Key differences

Although shale gas and oil technologies are similar to conventional gas and oil technologies, the main differences for shale gas and oil will be the prevalence of hydraulic fracturing and the overall scale of development needed for a project to be economically viable. This is because hydraulic fracturing is necessary to produce gas and oil from shale resources, and the amount of gas or oil recovered from each well is lower than is typical for conventional petroleum resources.

The geology of shale gas and oil resources differs from the geology of CSG resources. This leads to the following major differences in the profile of water use and production over the project life cycle:

- Shales will always require hydraulic fracturing to yield gas, whereas CSG requires hydraulic fracturing in only some wells. Shale gas developments will require more water up-front than CSG due to the requirement to hydraulically fracture every shale gas well.
- CSG almost always requires dewatering of the coal seam to allow gas production whereas shale gas and oil does not. For this reason, CSG developments have an order of magnitude greater volume of produced water than shale gas and oil. This leads to a greater need for wastewater treatment and disposal for CSG than for shale gas and oil. Conversely, shale gas and oil flowback and produced water are likely to have greater treatment requirements than for CSG-produced water because of their compositions (higher salinities plus other potential contaminants from the shale formation).

The produced water from shale gas and oil is likely to have a similar composition to produced water from conventional petroleum resources (the composition of these waters varies from resource to resource).

12.3 Material impacts of shale gas and oil development

The potential impacts of shale gas and oil activities were evaluated for their materiality. This qualitative assessment considered the intensity, scale and duration of the impact, and how often the impact may occur. The impacts were evaluated in the context of how these activities are likely to be conducted in Queensland, including the current regulatory regime. However, approaches for managing the potential impacts were not explored in detail. The assessment looks at potential impacts – that is, the impacts that *may* occur. It is important to emphasise that the focus is on the identification of potential impacts and high-level analysis of their materiality, not absolute risk estimation.

The only impacts identified as being highly material were workplace health and safety incidents, which have the potential to cause significant harm or fatalities to workers, or traffic accidents that may involve either workers or members of the public. This assessment did not consider the likelihood of impacts, as this would require an understanding of the probabilities of impacts occurring. The frequency with which impacts might happen was considered, looking at whether the impacts are inadvertent events (events that occur as accidents or failures), are an inevitable impact of shale gas and oil activities in certain circumstances, or happen all the time. By definition, workplace health and safety incidents, and traffic accidents are inadvertent events. Their materiality is high because of the intensity of the impact on those affected. These potential impacts are common to many workplaces, are well understood, and are not a particular problem for shale gas and oil activities.

The majority of moderately material impacts specific to shale gas and oil consistently identified in the literature relate to water. The four impact areas that were found to be the most material are:

- water use – where the water required for drilling and hydraulic fracturing will be drawn from and what impacts will accrue, particularly for competing users. Water requirements during shale development are high, and cumulative impacts will depend on scale of development and water sources used within a region. Water use for shale is still significantly less than for other uses (e.g. agriculture)
- water reuse and wastewater treatment – management of wastewater from shale gas and oil projects, including potential treatment options that may be employed for flowback and produced water, and potential beneficial reuse of waste water or treated waste water.
- water contamination – the potential for inadvertent surface spills and leaks, leading to impacts on surface water and groundwater, and the need for appropriate construction practices, management and monitoring
- long-term well integrity – the potential for old wells to become conduits for contamination, and how legacy issues will be managed both for point-source and cumulative impacts.

Moderately material potential impacts on native vegetation and fauna (quality and quantity of water for water-dependent ecosystems) and public health (drinking water) are related to impacts on water.

Other moderately material potential impacts for shale gas and oil are:

- disturbance and erosion of soil from the development of surface infrastructure (well pads, access tracks, pipeline installations)
- contamination of land or water through spills of waste materials (drilling fluids, hydraulic fracturing fluids, flowback water)
- human health impacts on those living in close proximity to shale gas and oil operations due to changes in air quality; this impact may not be prevalent in the remote areas of Queensland that are most prospective for shale gas and oil resources
- human health impacts on those living in shale gas and oil development regions due to stress resulting from rapid shale gas and oil development and its effects
- loss, decrease in quality, or fragmentation of habitat for native vegetation and fauna due to vegetation clearing for infrastructure development; these impacts will be very location specific
- introduction of invasive species (weeds), affecting agriculture, and native vegetation and fauna
- decreased access to traditional lands for Aboriginal and Torres Strait Islander communities.

12.4 Comparison of impacts with other oil and gas resource developments

As highlighted in Section 12.2, there are many similarities in the activities in shale gas and oil to those in other gas and oil resource developments, along with some key differences. Where the activities are similar, the impacts are also likely to be similar. Therefore, the impacts on a per well scale for shale gas and oil development will be very similar to those for other gas and oil developments. At the well pad scale, the main difference that may lead to an increased risk of potential impacts is the prevalence of hydraulic fracturing for shale gas and oil activities. The potential impacts related to water extraction and disposal, and impacts on surface or shallow groundwater resources from spills or leaks of fluids used as part of the hydraulic fracturing process is increased compared to other gas and oil activities. CSG does have higher volumes of produced water to manage in comparison to shale gas and oil activities.

The other potential impacts identified in Section 12.3 (workplace health and safety, human health impacts, impacts on land and native vegetation and fauna, weeds, access to traditional lands) will be very similar to those for CSG, although there will be some variation because of regional differences in the areas most prospective for shale gas and oil compared with those that have CSG development (i.e. most of the areas prospective for shale gas and oil are in extremely remote areas in comparison to areas of CSG development).

The scale of development means that shale gas and oil resources may have greater cumulative impacts than conventional petroleum resources, and a similar level of cumulative impacts to CSG development. However, detailed consideration of these impacts was outside of the scope of this review.

12.5 Requirements for regulatory focus

The two most relevant pieces of Queensland legislation for the regulatory management of petroleum and gas activities including shale gas and oil activities are the P&G Act and the EP Act. The Water Act is also important for the management of water use and mitigating impacts on water resources.

The P&G Act regulates the granting of rights to conduct petroleum activities, including to explore for, and develop, petroleum resources, as well as health and safety aspects of oil and gas activities. The role of this Act and subordinate legislation in managing potential impacts is to set minimum engineering requirements for the conduct of gas and oil development activities, with a focus on safety. The Act is administered by the Queensland Department of Natural Resources, Mines and Energy.

The P&G Act requires applicants for tenure to provide development plans and work programs for assessment as part of the tenure application process. Applicants must also demonstrate their financial and technical capabilities to conduct their planned activities. The P&G Act also requires the applicant to obtain an EA before authority to conduct petroleum activities can be granted.

The EP Act regulates activities to avoid, minimise or mitigate potential environmental impacts. The regulatory strategy adopted in the implementation of this act and subordinate legislation in managing impacts is to set objectives for environmental performance that operators must comply with. Prescriptive requirements are avoided to allow operators to develop innovative environmental solutions. This act is administered by the Queensland Department of Environment and Sciences.

The EP Act requires companies / operators to apply for an EA for the relevant activities they wish to carry out. An EA is a licence to operate under the EP Act. An EA sets out the environmental conditions that an operator must comply with to demonstrate that they are achieving the environmental objectives for their activities and minimising the potential impacts of each relevant activity on the environmental values identified for that project.

The regulator reviews this assessment and sets the EA conditions to mitigate or manage the risks identified. The regulator has developed standard and streamlined model conditions to streamline the process and to ensure that suitable standards are met.

In general, the process for deciding on the conditions of an EA begins with the applicant identifying potential impacts to environmental values and then in turn proposing environmental protection commitments which helps the administering authority decide the conditions of the environmental authority. Where environmental harm is unavoidable, the conditions of the environmental authority are designed to identify and authorise an acceptable level of environmental harm, and to ensure that any authorised environmental harm is managed and monitored appropriately. In some instances, particularly where large scale development is considered, an environmental authority application will be submitted after an EIS has been completed for a project.

When an environmental authority is granted, it becomes the primary regulatory document for a petroleum activity used by the administering authority to ensure environmental compliance.

The *Water Act 2000* is also important for shale gas and oil developments, because the taking of water for these activities will need to comply with the provisions of this Act. Authority holders have limited rights to take water under the P&G Act. The EP Act and Chapter 3 of the Water Act sets out the requirements that the authority holder must meet in exercising these rights. Any other access to, or interference with, water resources requires authorisation under Chapter 2 of the Water Act. The MERCP Act requires the development of a Land Access Code that sets the requirements for resource developers and their interactions with landholders. Resource operators also have to comply with other legislation relevant to their activities.

As part of the evaluation of the potential impacts of shale gas and oil development, this review evaluated the requirement for regulatory focus for potential impacts. As most technologies and activities are already conducted for other petroleum resources to some extent throughout Queensland, most impacts are anticipated to be covered under the current regulatory framework. However, impacts that may require additional attention during the assessment and approval process because they are new, or occur at an increased scale compared with previous experience, have been identified.

12.5.1 Potential impacts requiring a high degree of regulatory focus

These are impacts which are either related to activities unique or highly prevalent to shale gas and oil operations, or are not already part of other activities regularly conducted and regulated in Queensland.

- Impacts related to the taking of surface water or groundwater were identified as an area that have a high requirement for regulatory focus. The regulation of water use through existing legislation and allocation processes for petroleum resources is anticipated to cover the relevant water use impacts identified for shale gas and oil. However, the volumes of water for a shale gas and oil project are likely to be higher than for other oil and gas developments, and the potential impacts will need to be properly assessed for each development. This may require additional research to better understand the water resources that will need to be used.

12.5.2 Potential impacts requiring a moderate degree of regulatory focus

These are impacts related to activities in shale gas and oil operations that are already conducted to a similar extent and regulated in Queensland in other resource activities.

- Potential impacts from the disposal or reuse of wastewater (predominantly treated flowback water). This is similar to the management of the disposal of produced CSG water; however, options for treatment and safe disposal or reuse in the regions in which shale gas and oil resources are found will need to be assessed.

- Potential impacts relating to surface spills or leaks of chemicals, drilling fluids, hydraulic fracturing fluid, flowback water and produced water. The literature has identified these impacts as the most likely, because of the amount of fluids that will be handled as part of shale gas and oil operations. These impacts are already managed throughout the life cycle (including transport of chemicals, storage and treatment of drilling or hydraulic fracturing fluids, and treatment and disposal of flowback water and waste materials) for other gas and oil resources. However, the nature of these fluids in shale gas and oil, and the volumes used and produced are different from previous experience in Queensland. CSG has significantly higher volumes of produced water than are expected for shale gas and oil, but lower volumes of the other fluids.

- Potential impacts relating to hydraulic fracturing. Hydraulic fracturing for shale gas and oil will be undertaken at a larger scale, and with more activity in each well (multiple hydraulic fracture stages), than previously conducted in Queensland. Potential impacts are leaks or migration of hydraulic fracturing fluids during hydraulic fracturing operations, and induced seismicity. There is currently a requirement in the EA streamlined model conditions for petroleum activities that requires that a risk assessment must be carried out for every well prior to undertaking stimulation activities (which includes hydraulic fracturing operations) to ensure that stimulation activities are managed to prevent environmental harm. This condition was not developed as part of the streamlining process that produced the EA streamlined model conditions for petroleum activities. There may be opportunities to streamline this process in the future to ensure that risk is assessed thoroughly and efficiently. Engineering requirements under the P&G Act also address these impacts.
- Potential impacts relating to greenhouse gas emissions during the production of shale gas and oil. These impacts are cumulative and part of a global effect. The impact of an individual shale gas and oil project will be a very small increment of global emissions. However, increasing concern over greenhouse gas emissions means that mitigation of emissions as far as practical should be considered.
- Potential impacts relating to access to land and other surface activities. These include traffic volumes and surface disturbance from the addition of access tracks, well pads, pipelines and other infrastructure. The impacts of shale gas and oil developments in the regions in which shale gas and oil resources are found will need to be assessed.
- Potential socioeconomic impacts, including demand for local labour, and impacts on traditional land users in the regions in which shale gas and oil resources are found.

Appendix A Geology of shale gas and shale oil resources

Hydrocarbon resource overview

Hydrocarbons are the main constituents of crude oil and natural gas, which forms through the geologic transformation of organic matter in the subsurface. By usage, crude oil and natural gas is collectively referred to as petroleum and is composed of a range of different chemical constituents. Hydrocarbons in crude oil can be straight-chain (paraffinic; e.g. n-alkanes) and cyclic (naphthenic) in shape, aromatized or consist of solid to semi-solid asphaltic compounds with up to 60 carbon atoms (e.g. Hyne, 2012). By contrast, hydrocarbons in natural gas consist of short chains ranging from one (dry gas) to five (wet gas) carbon atoms. Typical hydrocarbon compositions of crude oil and natural gas are shown in Table 20 and Table 21, respectively. Besides hydrocarbons, petroleum fluids also contain carbon-dominated compounds with heteroatoms such as nitrogen, sulphur, and oxygen (NSO compounds) as well as elemental sulphur, carbon dioxide (CO_2), hydrogen sulphide (H_2S), nitrogen (N_2) and trace amounts of noble gases (Peters, Walters and Moldowan, 2004b; Hyne, 2012; Huc, 2013).

Table 20 Hydrocarbon composition in crude oil

Adapted from Hyne (2012)

Hydrocarbon group	Weight percent (%)	Percent range (%)
Paraffins	30%	15% to 60%
Naphthenes	49%	30% to 60%
Aromatics	15%	3% to 30%
Asphaltics	6%	Remainder

Table 21 Typical hydrocarbon composition of natural gas

Adapted with modifications from Hyne (2012). Cn refers to the number of carbon atoms in the compound.

Compound	Percent range (%)
Methane (C_1)	70% to 98%
Ethane (C_2)	1% to 10%
Propane (C_3)	Trace to 5%
Butane (C_4)	Trace to 2%
Pentane (C_5)	Remainder

Organic-rich sedimentary rocks such as shale and limestone frequently form the source rock for oil and natural gas deposits and can vary in their organic content, thickness, extension and the nature of the fossilized organic matter contained within (e.g. Peters, Walters and Moldowan, 2004b; Huc, 2013). These rocks are deposited in sedimentary basins, which are tectonically induced depressions in the Earth's upper crust and usually occupied by lakes, seas or oceanic bodies (e.g. Hyne, 2012; Huc, 2013). Over time, such basins are progressively filled with sediment over the course of tens to hundreds of millions of years (e.g. Huc, 2013). Organic matter that was deposited with the sedimentary rocks transforms as a result of thermal cracking (also referred to as maturation) associated with a temperature increase due to progressive burial, the local heat flow history and the thermal conductivity of the sediment pile (e.g. Huc, 2013). Organic matter from which hydrocarbons are produced during burial and heating is known as kerogen (e.g. Killops and Killops, 2004; Peters, Walters and Moldowan, 2004b).

The composition and amounts of hydrocarbons generated from a particular kerogen vary progressively with increasing maturity (Figure 32). Organic matter is typically described as immature, mature and post-mature, depending on the relation to the oil-generative window (Tissot and Welte, 1984). With increasing burial, temperatures increase and result in sufficient thermal energy for hydrocarbon generation. The evolved hydrocarbons will decrease in size with increasing maturity as a result of catagenesis – the thermal alteration of organic matter by burial at a temperature range of approximately 50 to 150˚C and geostatic pressure from 300 to 1500 bars (Peters, Walters and Moldowan, 2004b). On this basis, hydrocarbon generation during catagenesis can be divided into oil, wet gas and dry gas zones. The oil generation zone (also known as the oil window) results in the production of liquid hydrocarbons of low-to-medium molecular weight. While the oil generation zone is typically stated to be between 60 and 150˚C, the major phase typically occurs between 100 and 150˚C and corresponds to a depth of approximately 2.5 to 4.5 km (Mackenzie and Quigley, 1988; Killops and Killops, 2004).

Hydrocarbon gases are produced at a range of different depths and to a temperature of approximately 230˚C. Closer to the surface, natural gas mostly comprises biogenic methane and is produced by methanogenic microorganisms (e.g. Tissot and Welte, 1978). The composition of natural gas changes in the later stages of catagenesis, ranging from wet gas, where there is significant amounts of associated C_2 to C_5 as well as condensate hydrocarbons, to dry gas which is composed of little more than methane (e.g. Tissot and Welte, 1978). Typically, hydrocarbons from C_1 to C_4 are considered to be gaseous and those $\geq C_6$ are liquid. C_5 hydrocarbons can be either gases or liquids at surface, depending on their structure. Gas condensates are other short-chain hydrocarbons that condense out from the gaseous phase under reduced pressure at the surface. Condensates (also known as gas condensates) refer to short-chain liquid hydrocarbons that condense from the gaseous phase at the surface and is very light in density and transparent to yellowish in colour (Hyne, 2012).

Shale resource characteristics

Shales defined

Shale is the most abundant sedimentary rock and acts as both the source and reservoir in shale gas and oil resources. From a strictly geological perspective, shale is characterised as a finely layered, fissile sedimentary rock composed of fine-grained silt and clay-sized particles with a diameter less than 0.0039 mm (e.g. *Zou et al*, 2013). From an engineering perspective, however, a shale constitutes any rock type containing at least 30% clay minerals (e.g. Farrokhrouz and Asef, 2013) and can be applied to any mudrock. Most Barnett shales, for example, are siliceous mudstones, rich in quartz, and may be considered argillaceous siltstones (Carpenter, 2014). Regardless of the type of definition used, matrix porosity in these shales is less than 10%, and permeability is less than 1 mD (millidarcy) (Zou *et al.*, 2013). Variations in the mineral composition of shale contribute to the diversity of this rock type and include siliceous shale, carbonaceous shale, ferruginous shale, calcareous shale and sandy shale. 'Black shale' is a common term widely used to describe dark coloured, fine-grained shale that is relatively rich in organic matter with organic carbon ranges between 1% and 30%, although values outside this range exist (Weissert, 1981). Shale formed in both lacustrine and marine settings with black, organic-rich shales typically developing in depositional environments that are oxygen-poor and sulphide-rich, such as closed bays, lagoons, deep lakes and deep shelfs (Jiang, 2003).

Several key factors determine whether or not a shale play is economic:

- total organic carbon (TOC) content, which is the total amount of organic material present in the rock expressed as a percentage of weight
- the organic matter type, which determines broadly whether the kerogen will produce oil or gas
- thermal maturity to indicate the degree to which a particular shale unit has been heated over time enough for gas or oil to have been produced
- the thickness of the organic-rich shale unit, which indicates reservoir extent and the amount of gas stored
- porosity and permeability of shale for petroleum holding capacity and sustainable gas production.

These factors are important features in determining the prospectivity of a shale play. Each of these factors is discussed in greater detail below.

Total organic carbon content

TOC is an indicator of the total amount of organic matter present in the sedimentary rock and is expressed as a weight percent (wt %; Ronov, 1958). The hydrocarbon-generating potential of this measure is commonly interpreted by using a semi-quantitative scale that groups wt % into categories such as poor, fair, good, and very good (Peters, 1986; Jarvie, 1991). Such a classification system is informative and forms a first step in understanding shale source rocks.

Organic matter types

While determining the amount of organic carbon is important, it is necessary to recognise that organic matter can differ in its make-up and the ability to produce petroleum can vary. Some types of organic matter will generate oil, others will form gas and some will produce no petroleum (Tissot, Durand and Espitalie, 1974). In order for organic matter to generate hydrocarbons, the carbon has to be associated with hydrogen. If more hydrogen is associated with the carbon, then more hydrocarbons can be generated. Therefore, it is necessary to determine the amount of hydrogen present in the organic matter.

The nature of hydrocarbons a source rock can generate is determined by the type of kerogen found in the sedimentary rock. Three basic kerogen types are recognised:

- Type I, derived primarily from algal material deposited principally in lacustrine environments that produces mainly waxy oil
- Type II, derived from autochthonous organic matter deposited under reducing conditions in marine environments that produce mainly naphthenic oil trace to 5%
- Type III, derived from terrestrial plant debris and/or aquatic organic matter deposited in an oxidizing environment that produces mainly gas (e.g. Tissot, Durand and Espitalie, 1974).

Few source rocks contain only one type of kerogen. More prevalent are mixed kerogen types, such as Type I or II with Type III or Type I, II, or III with Type IV (e.g. Dembicki, 2009).

Thermal maturity

Thermal maturity indicates the degree to which organic matter has been heated over time for oil or gas to have been produced. The generation of petroleum is therefore a consequence of the kerogen structure attempting to attain thermodynamic equilibrium in response to subsurface heat and pressure (e.g. Killops and Killops, 2004; Peters, Walters and Moldowan, 2004b). Evaluating the thermal maturity of sedimentary sequences is an important aspect when assessing petroleum systems. It allows insights into the thermal history of a basin to better understand the breakdown of kerogen in buried rock (Peters, Walters and Moldowan, 2004a). A number of petrographic and geochemical techniques have been developed to assess the level of thermal maturation of organic matter. The techniques include vitrinite reflectance (e.g. McCartney and Teichmüller, 1972), organic matter fluorescence (e.g. P*radier et al*., 1991), spore and microfossil colouration (e.g. McNeil, Issler and Snowdon, 1996), Rock Eval pyrolysis (e.g. McCartney and Teichmüller, 1972; Peters, 1986; Nunez-Betelu and Baceta, 1994) and various molecular markers (Peters, Walters and Moldowan, 2004a, 2004b). Vitrinite reflectance, Rock Eval pyrolysis and molecular markers are the most widely used maturity parameters employed in assessing the thermal maturity in shale resources. These measurements are described in greater detail below:

- Vitrinite is a primary component of coal and many sedimentary kerogens that formed from humic peats and the lignin-cellulose cell walls of higher plants (Teichmüller, 1989). The reflectance of vitrinite was first observed to increase with thermal maturation in a predictable manner in coals (Teichmüller, 1982) and this systematic increase in reflectance was related to the hydrocarbon generation history of sediments.
- Rock Eval is a programmed pyrolysis technique that subjects rock samples to high temperatures to mimic geological conditions in a sedimentary basin. The technique uses both pyrolysis and oxidation ovens to heat samples in a programmed series of stages that range from 100 to 850˚C (McCarthy *et al*., 2011).
- Molecular maturity parameters, such as those based on hopanes, steranes and aromatic hydrocarbons, can also provide important information on the thermal maturity of shale. They are based on the transformation of compounds into more stable forms as a result of thermal maturation. Ratios of such compounds have been used in assessing maturity of source rocks and petroleum (e.g. Radke, Welte and Willsch, 1982).

Thickness of organic-rich shale units

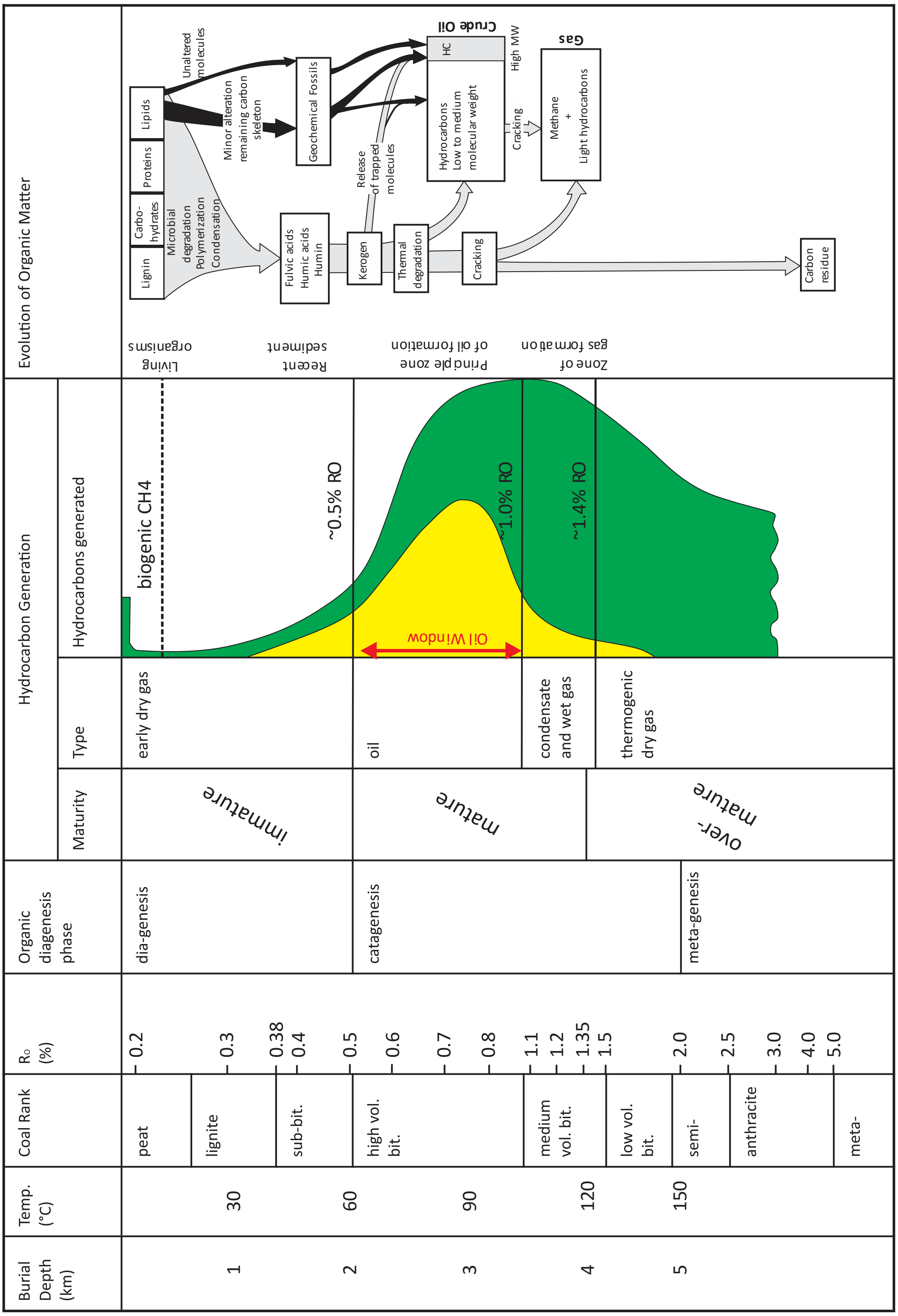
Good shale resources are characterised by a substantial thickness along with a large surface area of fine-grained sediment and organic matter for oil and gas to form and for gas to adsorb (e.g. Speight, 2012). According to the US Geological Survey (USGS) assessment methodology, a minimum thickness of 15 m of organic-rich shale is required (Charpentier and Cook, 2011). As a general rule, thicker shale sequences make better targets. Some North American shale targets, such as the Bakken Formation oil play in the Williston Basin, are less than 50 m thick in many areas and are yielding economic rates of flow (e.g. Speight, 2012). The required thickness to economically develop a shale target may decrease in the future as drilling and completion techniques improve, porosity and permeability detection techniques progress, and the price of oil and gas increases. Such developments would add a substantial amount of resources and reserves to a province (e.g. Speight, 2012).

Porosity and permeability of the shale matrix

Porosity reflects the ability of shale to hold fluids such as water, oil, or natural gas. Since shale is composed of very small particle sizes, the pores are very small and range in size from 1 to 3 nm to 400 to 750 nm (Loucks *et al*., 2009). Nevertheless, pore spaces can take up a significant volume of the rock ranging from 4% to 10% (Zou *et al*., 2013). This property allows shale to hold significant amounts of water, gas, or oil but not to be able to effectively transmit them because of the low permeability. Furthermore, abundant inner surface areas of these pores can store large amounts of gas by adsorption (Zou *et al*., 2013). Therefore, porosity is an important property when prospecting for shale plays. Related to porosity is the pore pressure, which is critical in liquids-rich shale plays and beneficial in all shale plays as it improves reservoir drive, recovery and safety during drilling (Ahmad and Rezaee, 2015). It refers to the pressure of the fluid contained in the pore space of the rocks and is an integral part of the formation evaluation process. Pore pressure prediction can be achieved via a range of different investigations and include well log and mud log data. If pore pressure evaluation is coupled to other shale parameters, such as TOC and thermal maturity level, it can help with the identification of sweet spots (Ahmad and Rezaee, 2015).

In conventional reservoirs, petroleum is typically hosted in reservoirs with a permeability greater than 1 mD and can be extracted via traditional techniques (e.g. Speight, 2013). Unconventional petroleum sources, by contrast, are found in reservoirs with relatively low permeability (<1 mD) and hence cannot be extracted by conventional methods (e.g. Speight, 2012). The very fine sheet-like clay mineral grains and laminae of shale result in a permeability that is limited horizontally and extremely limited vertically. Consequently, gas trapped in shale cannot move easily except over geologic time in the order of millions of years (e.g. Speight, 2012).

Each shale formation is characterised by different geological characteristics, which affect the way gas can be produced, the required technologies, and the economics of production (e.g. Speight, 2012). Furthermore, different parts of a prospective shale deposits will also have different characteristics. Small sweet spots or core areas of the shale may provide much better production than the remainder of the formation. The presence of natural fractures that enhance permeability is a contributing factor in these sweet spots. In general, higher shale permeability results in higher diffusion rates of petroleum to fractures and a higher rate of flow to the wellbore (Bustin and Bustin, 2008). In addition, more fractured shale with sufficient permeability should result in higher production rates (Bustin and Bustin, 2008) and a larger drainage area for hydrocarbon recovery (Walser and Pursell, 2007; Cramer, 2008). Therefore, determining the permeability and any fractures in prospective shale formations is a key requirement for efficient petroleum production.



Hydrocarbon generation is dependent on the nature of the organic matter that is buried in sediments and the pressure (depth) and temperature that that organic matter is subjected to over time.
Source: Tissot and Welte, 1978; after Mastalerz *et al.*, 2013

Figure 32 General scheme of hydrocarbon formation as a function of burial of the source rock

Appendix B Bioregions

Table 22 Full bioregion descriptions from the Revision of the Interim Biogeographic Regionalisation for Australia (IBRA) and the Development of Version 5.1

Source: (Environment Australia, 2000)

Bioregion	Description
Brigalow Belt **(This bioregion is a combination of two IBRA bioregions Brigalow Belt North and Brigalow Belt South, as well as some small areas of the Darling River Plain Subregion)**	**Brigalow Belt North** Permian volcanics and Permian-Triassic sediments of the Bowen and Galilee Basins, Carboniferous and Devonian sediments and volcanics of the Drummond Basin and coastal blocks, Cambrian and Ordovician rocks of the Anakie inlier and associated Tertiary deposits. Subhumid to semiarid. Woodlands of ironbarks (E. melanophloia, E. crebra), poplar box and Brown's box (E. populnea, E. brownii) and brigalow (Acacia harpophylla), blackwood (A. argyrodendron) and gidgee (A. cambagei). Region reaches the coast in the dry coastal corridor of Proserpine – Townsville. **Brigalow Belt South** Predominantly Jurassic and younger deposits of the Great Artesian Basin and Tertiary deposits with elevated basalt flows. Subhumid. Eucalyptus woodlands and open forests of ironbarks, poplar box, spotted gum (E. maculata), cypress pine (Callitris glaucophylla), Bloodwoods (e.g. E. trachyphloia, E.hendersonii ms) brigalow-belah forests (E. harpophylla, Casuarina cristata) and semi-evergreen vine thicket. **Darling Riverine Plain** Alluvial fans and plains; summer/winter rainfall in catchments, including occasional cyclonic influence; grey clays; woodlands and open woodlands dominated by Eucalyptus spp.
Channel Country **(Includes small areas of the Simpson Strzlecki Dunefields from IBRA)**	Low hills on Cretaceous sediments; forbfields and Mitchell grass downs, and intervening braided river systems of coolibah E.coolibah woodlands and lignum/saltbush Muehlenbeckia sp./Chenopodium sp. shrublands. (Includes small areas of sand plains.) **Simpson Strzelecki Dunefields** Arid dunefields and sandplains with sparse shrubland and spinifex hummock grassland, and cane grass on deep sands along dune crests. Large salt lakes, notably Lake Eyre and many clay pans are dispersed amongst the dunes. Several significant arid rivers terminate at Lake Eyre, Cooper Creek and Warburton River. They are fringed with coolibah and redgum woodlands.
Central Queensland Coast	Humid tropical coastal ranges and plains. Rainforests (complex evergreen and semi-deciduous notophyll vine forest), Eucalyptus open forests and woodlands, Melaleuca spp. wetlands.

Bioregion	Description
Cape York Peninsula	Complex geology dominated by the Torres Strait Volcanics in the north, the metamorphic rocks and acid intrusive rocks of various ages of the Coen–Yambo Inlier which runs north- south along the eastern margin of the region and encompasses the high-altitude/high-rainfall areas of Iron Range and McIlwraith Range. The deeply dissected sandstone plateaus and ranges of the Battle Camp Sandstones lie in the south of the region adjacent to the undulating Laura Lowlands composed of residual weathered sands and flat plains of colluvial and alluvial clays, silts and sands. The west of the region is dominated in the south by the extensive Tertiary sand sheet dissected by intricate drainage systems of the Holroyd Plain, the Tertiary laterite of the undulating Weipa Plateau, the low rises of Mesozoic sandstones, with the northern extension of the Weipa Plateau and extensive coastal plains adjoining the Gulf of Carpentaria. Extensive aeolian dunefields lie in the east associated with Cape Bedford/Cape Flattery in the south and the Olive and Jardine Rivers. The vegetation is predominantly Eucalyptus tetrodonta and Corymbia tessellaris/C. clarksoniana woodlands, Melaleuca viridiflora woodlands, heathlands and sedgelands, notophyll vine forests, with semi-deciduous mesophyll vine forests on the eastern ranges and deciduous vine thickets on drier western slopes. Extensive mangrove forests are found in Kennedy Inlet in the north east of the region and estuaries on both the west and east coasts. Tropical humid/maritime climate, with rainfall varying from 1000 mm to 1600 mm.
Desert Uplands	Ranges and plains on dissected Tertiary surface and Triassic sandstones; woodlands of E.whitei, E.similis and E.trachyphloia.
Einasleigh Uplands	High plateau of Palaeozoic sediments, granites, and basalts; dominated by ironbark (Eucalyptus spp.) woodlands.
Gulf Plains	Marine and terrestrial deposits of the Carpentaria and Karumba basins; plains, plateaus and outwash plains; woodlands and grasslands.
Mitchell Grass Downs	Undulating downs on shales and limestones; Astrebla spp. grasslands and Acacia low woodlands. Grey and brown cracking clays.
Mulga Lands	Undulating plains and low hills on Cainozoic sediments; red earths and lithosols; Acacia aneura shrublands and low woodlands.
New England Tablelands	Elevated plateau of hills and plains on Palaeozoic sediments, granites and basalts; dominated by stringy bark/peppermint/box species, including E. caliginosa, E. nova-anglica, E. melliodora and E. blakleyi.
Northwest Highlands **(Contains a small component of the Gulf Fall and Uplands)**	Rugged hills and outwash, primarily associated with Proterozoic rocks; skeletal soils; low open eucalypt woodlands dominated by Eucalyptus leucophloia and E.pruinosa, with a Triodia pungens understorey. Semi-arid. **Gulf Fall and Uplands** Undulating terrain with scattered low, steep hills on Proterozoic and Palaeozoic sedimentary rocks, often overlain by lateritised Tertiary material; skeletal soils and shallow sands; Darwin Boxwood and Variable-barked Bloodwood woodland to low open woodland with spinifex understorey.

Bioregion	Description
Southeast Queensland	Metamorphic and acid to basic volcanic hills and ranges (Beenleigh, D'Aguilar, Gympie, Yarraman Blocks) sediments of the Moreton, Nambour and Maryborough Basins, extensive alluvial valleys and Quaternary coastal deposits including high dunes on the sand islands such as Fraser Island. Humid. Eucalyptus-Lophostemon-Syncarpia tall open forests, Eucalyptus open forests and woodlands, subtropical rainforests often with Araucaria cunninghamii emergents and small areas of cool temperate rainforest dominated by Nothofagus moorei and semi-evergreen vine thickets, Melaleuca quinquenervia wetlands and Banksia low woodlands, heaths and mangrove/saltmarsh communities.
Wet Tropics	The bioregion is dominated by rugged rainforested mountains, including the highest in Queensland Mt Bartle Frere (1622m). It also includes extensive plateau areas along its western margin, as well as low lying coastal plains. The most extensive lowlands are in the south, associated with the floodplains of the Tully and Herbert Rivers. Most of the bioregion drains to the coral sea from small coastal catchments, but higher western areas drain in the south into the Burdekin River, and in the north into tributaries of the Mitchell River. The region contains extensive areas of tropical rainforest, plus beach scrub, tall open forest, open forest, mangrove and Melaleuca woodland communities.

Shortened forms

ATP	Authority to prospect
Bcf	Billion cubic feet
BTEX	Benzene, toluene, ethylbenzene and xylene
CO_2	Carbon dioxide
CSG	Coal seam gas
EA	Environmental authority
EIA	Environmental impact assessment
EIS	Environmental impact statement
GAB	Great Artesian Basin
GL	Giga litre (1,000,000,000 litres)
H_2S	Hydrogen sulphide
km	Kilometre
LPG	Liquefied petroleum gas
m	Metre
mD	millidarcy
MJ	Megajoule (1,000,000 joules)
M_L	Richter magnitude (earthquakes, seismic events)
M_W	Moment magnitude (earthquakes, seismic events)
ML	Mega litre (1,000,000 litres)
MNES	Matter of national environmental significance
nm	Nanometres
NGL	Natural gas liquids
NORM(S)	Naturally occurring radioactive materials
PAH	Polycyclic aromatic hydrocarbons
PCBU	Persons conducting a business or undertaking
PFL	Petroleum facility licence
PJ	Petajoule (10^{15} joules, or 1,000,000,000 MJ)
PL	Petroleum lease
PPL	Petroleum pipeline licence
Tcf	Trillion cubic feet
TOC	Total organic carbon

v/v	Volume per volume (a measure of concentration)
VOC	Volatile organic compound

Glossary

Absorbed	Molecules bound to within a particle. Absorption can bind methane and carbon dioxide within shale or coal.
Adsorbed	Molecules bound to a particle surface. Adsorption can bind methane and carbon dioxide, for example, to coal particles.
Anthropogenic	Changes in natural systems caused by human activity.
Anticline	A fold in stratified rock that is convex up, with the oldest rocks at its core. Layers of rock are ridge shaped.
Appraisal well	A petroleum well drilled to test the potential of one or more natural underground reservoirs for producing or storing petroleum.
Aquifer	An identifiable stratigraphic formation that has the potential to produce useful flows of water and may include formations where, due to hydraulic fracturing activity, a changed hydraulic conductivity allows such water flows.
Aquitard	A saturated geological unit that is less permeable than an aquifer and incapable of transmitting useful quantities of water. Aquitards often form a confining layer over an artesian aquifer.
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.
Associated water	See produced water.
Authority holder	The entity that holds a resource authority for petroleum activities. Authorities include authority to prospect, petroleum licence, petroleum facilities licence, and petroleum pipeline licence. The authority allows the authority holder to conduct the authorised activities as well as setting out obligations.
Authority to Prospect	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to conduct exploration for petroleum, oil, coal seam gas and natural gas in Queensland. Permitted activities include exploring for petroleum, testing petroleum production, evaluating feasibility of petroleum production, and evaluating or testing natural underground reservoirs for the storage of petroleum or a prescribed storage gas.
Biocide	An additive intended to destroy, deter, render harmless, prevent the action or otherwise exert a controlling effect on microorganisms. Commonly used in drilling and hydraulic fracturing fluids.
Biodiversity	Variety of life forms including the different plants, animals and microorganisms, the genes they contain and the ecosystems they form. Biodiversity is usually considered at three levels: genetic, species and ecosystem.
Biogenic	Produced by living organisms. Coal seam gas is typically biogenic and is produced by microorganisms that consume coal.
Block	A sub-division of land used to define the location and size of petroleum and gas authorities. A block is defined in the *Petroleum and Gas (Production and Safety) Act 2004* as an area five minutes in latitude by five minutes in longitude.

Bore	Generally refers to a narrow, artificially constructed hole drilled to intercept, collect or store water from an aquifer, or to passively observe or collect groundwater information. Also known as a boreholes, drill holes or piezometer holes.
Brine	Saline water with a total dissolved solid concentration greater than around 40,000ppm. Sea water has total dissolved solids of around 30,000ppm.
Casing strings	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. Often multiple casings are used to provide additional barriers between the formation and well.
Coal seam gas	A form of natural gas (generally 95 to 97% pure methane, CH_4) extracted from coal seams, typically at depths of 300 to 1000 m. Also called coal seam methane (CSM) or coalbed methane (CBM).
Compressional	A tectonic regime where the maximum principal tectonic stress is horizontal causing shortening or compression of geological layers.
Condensate	Hydrocarbons that are in the vapour phase at reservoir conditions but condense to form liquids under atmospheric conditions.
Contaminant (environmental)	Biological, chemical, physical, or radiological substance which, in sufficient concentration, can adversely affect living organisms through air, water, soil, and/or food.
Cryogenic	Processes at ultra-low temperatures (below -190°C).
Cumulative impacts	Impacts that occur due to multiple direct or indirect impacts on the same system.
Data acquisition authority	A resource authority that allows the holder to conduct limited geophysical survey activities and collect data in areas immediately adjacent to their authority to prospect.
Development well	A petroleum well which produces or stores petroleum.
Decommissioning	The process to remove a well or other infrastructure from service.
Desorption	The process of removing gas from sorption sites by reducing the pressure (primarily through removal of water from the coal seams).
De-watering	The lowering of static groundwater levels through complete extraction of all readily available groundwater, usually by means of pumping from one or several groundwater bores.
Direct impact	Impacts that occur as a direct result of an activity.
Drawdown	A lowering of the water table of an unconfined aquifer or of the potentiometric surface of a confined aquifer, typically caused by groundwater extraction.
Drill cuttings	Fragments of rock 'cut' by the drill bit during drilling.
Drilling fluids	Fluids that are pumped down the wellbore to lubricate the drill bit, carry rock cuttings back up to the surface, control pressure, stabilise the well and for other specific purposes. Also known as drilling muds.
Dry gas	Natural gas that contains little to no condensate or liquid hydrocarbons. Predominately methane. Dry gas usually defined as less than 0.1 g of condensable liquids for 1000 cubic feet. See also wet gas.

Environmental authority	An environmental authority issued by the administering authority under Chapter 5 of the *Environmental Protection Act 1994*.
Earthquake	Vibrations in the earth caused by sudden movements along fractures or fault planes. Generally used to refer to events that can be felt at the surface. See also seismic event.
Environmental impact statement	A document(s) describing a proposed development or activity and assessing the possible, probable, or certain effects of that proposed development on the environment and other potential environmental values. In Queensland, the requirements for an EIS are regulated by the *Environmental Protection Act 1994* or *State Development and Public Works Organisation Act 1971* for coordinated projects.
Erosion	Erosion is the movement of soil by wind or water, at a rate greater than latent conditions.
Exploration well	A petroleum well that is drilled to test for the presence of petroleum or natural underground reservoirs suitable for storing petroleum, or to obtain stratigraphic information for the purpose of exploring for petroleum
Extensional	A tectonic regime where the maximum principal tectonic stress is vertical causing lengthening of geological layers.
Flaring	Burning of gas that cannot be used commercially or economically piped for use elsewhere or gas that needs to be released for safety reasons. Associated flare pits dug into the earth contain fluids produced from flaring as well as produced water. See also venting.
Flowback water	The volume of fluid that is pumped back to the surface following hydraulic fracturing operations. It typically contains fracturing fluid, water used to flush the fracturing fluid out of the wellbore, and some formation water from geological formations surrounding the fracturing zone.
Formation water	Naturally occurring groundwater that is within the shale formation.
Fugitive emissions	In the natural gas industry, fugitive emissions are considered to include all greenhouse gas emissions from exploration, production, processing, transport and distribution of natural gas, except those from fuel combustion. Emissions from flaring of natural gas are also considered to be fugitive emissions.
Gas sweetening	A process to remove acid gases (hydrogen sulfide and carbon dioxide) from a natural gas stream.
Geochemical	Relating to the chemistry of geological material (rocks, the Earth).
Geomechanical	Relating to mechanical properties of geological material (rocks, the Earth).
Geogenic chemical	A naturally occurring chemical originating from the Earth e.g. from geological formations.
Greenhouse gas	Gas in the atmosphere that absorbs and emits radiation energy in the thermal infrared band. These gases include carbon dioxide, methane and nitrous oxides.
Global warming potential	A measure of how much energy the emissions of one tonne of a gas will absorb over a given period of time, relative to the emissions of one tonne of carbon dioxide.
Higher order hydrocarbons	Hydrocarbons with multiple carbon atoms. Methane is the simplest hydrocarbon with one carbon atom, ethane has two, propane three and so on.

Horizontal drilling	Drilling of well in a horizontal or near-horizontal plane, usually within the target formation. Requires the use of directional drilling techniques that allow the deviation of the well on to a desired trajectory. Horizontal wells typically penetrate a greater length of the reservoir than a vertical well, significantly improving production while minimising the surface footprint of drilling activities.
Hydraulic fracturing	Also known as 'fracking', 'fraccing' or 'fracture simulation', is one process by which hydrocarbon (oil and gas) bearing geological formations are 'stimulated' to enhance the flow of hydrocarbons and other fluids towards the well. In most cases hydraulic fracturing is undertaken where the permeability of the formation is initially insufficient to support sustained flow of gas. The hydraulic fracturing process involves the injection of fluids, proppant and additives under high pressure into a geological formation to create a conductive fracture. The fracture extends from the well into the production interval, creating a pathway through which gas is transported to the well.
Hydraulic fracturing fluid	The fluid injected into a well for hydraulic fracturing. Consists of a primary carrier fluid (usually water or a gel), a proppant such as sand and one or more additional chemicals to modify the fluid properties.
Hydraulic fracture spread	The surface plant and equipment required for hydraulic fracturing.
Hydraulic fracture stage	A zone in a well that is hydraulically fractured at one time. Individual wells may have multiple hydraulic fracture stages.
Impact	The difference between what would happen as a result of activities and processes and what would happen without them. Impacts may be changes that occur to the natural environment, community or economy. Impacts can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes.
Indirect impact	Impacts that occur as a result of a pathway of cause and effect.
Cumulative impacts	Impacts that occur due to multiple direct or indirect impacts on the same system.
Induced seismicity	Seismic events that occur as a result of anthropogenic activity.
Kerogen	Organic matter from which hydrocarbons are produced during burial and heating.
Microseismic event	Small seismic events that can only be detected with sensitive monitoring equipment.
NORM	Naturally occurring radioactive material (NORM). Radioactive materials which occur naturally and where human activities increase the exposure of people to ionising radiation. May be original radioactive materials, such as uranium and thorium, or their decay products.
Offset well	An existing wellbore which is close to a proposed well, and which provides a source of information for planning the proposed well.
Open-hole	An un-cased section of a well.
Packer	A device that can be run into a well with a small initial outside diameter and then expanded to seal the wellbore. Used to isolate zones with in a well in applications such as multi-stage hydraulic fracturing.
Perforation	A channel through the casing and cement in a well to allow fluid to flow between the well and the reservoir (hydraulic fracturing fluids in to the reservoir or gas and

	oil in to the well). The most common method uses perforating guns equipped with shaped explosive charges that produce a jet.
Permeability	The measure of the ability of a rock, soil or sediment to yield or transmit a fluid. The magnitude of permeability depends largely on the porosity and the interconnectivity of pores and spaces in the ground
Petrophysical	Physical and chemical properties of rocks and their contained fluids
Petrochemical	Chemical substance obtained from petroleum or natural gas.
Petroleum facility licence	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to operate a petroleum facility, such as a gas processing facility in Queensland.
Petroleum lease	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to explore for, develop and produce petroleum (gas and oil) in Queensland.
Petroleum pipeline licence	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to construct and operate a petroleum pipeline in Queensland.
Petroleum survey licence	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to enter land to survey the proposed route for a pipeline or petroleum facility in Queensland.
Plug	A device or material placed within a well to prevent vertical movement of fluids. May be a mechanical device or cement.
Plugged and abandoned	A permanently closed well, with plugs inserted to isolate sensitive formations and aquifers and surface infrastructure removed.
Porosity	The proportion of the volume of rock consisting of pores, usually expressed as a percentage of the total rock or soil mass.
Potential commercial area	A resource authority under the *Petroleum and Gas (Safety and Production) Act 2004* that allows the holder to evaluate the potential production and market opportunities for the resource.
Principal stress	The stress component perpendicular to a given plane and may be compressional or tensional (i.e. no shear stress component). Also known as normal stress.
Produced gas	Gas brought to the surface via a well.
Produced water	Water brought to the surface via a well.
Production zone	The section from well from which fluids or gas are produced.
Proppant	A component of the hydraulic fracturing fluid system comprised of sand, ceramics or other granular material that 'prop' open fractures to prevent them from closing when the injection is stopped.
Pulsed gas flow	Gas flowing up a well with water will separate in to pulses of gas (large bubbles) with water.
Reservoir	A geological formation with adequate porosity, fractures or joints that can store hydrocarbons.
Rotary mud drilling	A drilling method where the drill bit is rotated to cut the rock and a drilling mud (or drilling fluid) used to lubricate the drill bit and lift cuttings from the well.

Seismic event	Vibrations in the earth caused by sudden movements along fractures or fault planes. See also earthquake.
Seismic survey	A method for imaging the sub-surface using controlled seismic energy sources and receivers at the surface. Measures the reflection and refraction of seismic energy as it travels through rock.
Shale gas	Shale gas is natural gas generally extracted from a fine grained sedimentary rock which has naturally low permeability. The gas has usually formed in place (source rock is the reservoir).
Shale oil	Shale oil is oil generally extracted from a fine grained sedimentary rock which has naturally low permeability. The oil has usually formed in place (source rock is the reservoir).
Slickwater	A water-based hydraulic fracturing fluid with additives to reduce the viscosity, allowing increased fluid flow and pumping rates.
Source rock	Geological formations that are the source for hydrocarbons.
Stage	See hydraulic fracture stage.
Stimulation	Well stimulation is an activity undertaken to restore or improve productivity of a well. Well stimulation techniques include hydraulic fracturing and matrix treatments. Matrix stimulation treatments include acid, solvent and chemical treatments to improve the permeability of the near-wellbore formation.
Stress	Force applied to a body with units of force per area. Rocks within the earth are subjected to stresses caused by the weight of overlying rocks and tectonics (movement within the earth).
Synclines	A fold in stratified rock that is convex down, with the youngest rocks at its core. Layers of rock are valley shaped.
Tectonic stress	Underground pressure in the earth's crust caused by weight and movement of the tectonic plates (lithosphere).
Tenement	An area of land held by an authority holder. In the context of this report, may be an authority to prospect, a petroleum lease, a petroleum facilities lease or a petroleum pipeline lease.
Thermal maturation	The extent of heat driven reactions that alter organic matter, such as their conversion to petroleum.
Thermogenic	Produced by thermal process. Shale gas and oil are typically thermogenic and are produced by thermal maturation of organic matter.
Tight gas	Natural gas trapped in ultra-compact reservoirs characterised by very low permeability.
Toxicity	Inherent property of an agent to cause an adverse biological effect.
Transpressional	A compressional tectonic regime where the maximum principal tectonic stress is horizontal and shortening is taking place across a dominantly strike-slip fault.
Unconventional resource	Petroleum (oil and gas) resources that cannot be developed using conventional oil and gas technologies. Includes coal seam gas, shale gas and oil, tight gas, basin centred gas.

Venting	Release of gas directly to the atmosphere. Venting is carried out when the gas cannot be used commercially or economically piped for use elsewhere or gas that needs to be released for safety reasons and that cannot be flared.
Volatile organic compounds	Organic chemicals that have a high vapor pressure at atmospheric conditions.
Water monitoring authority	A resource authority (in the context of this report, issued under the *Petroleum and Gas (Safety and Production) Act* 2004) that allows the holder to monitor conduct activities outside of an authority to prospect or petroleum lease so that they can comply with their water management obligations.
Well	A hole drilled in to the earth from which petroleum or other fluids can be produced.
Wellhead	The surface infrastructure that controls pressure and access at the top of a well.
Well pad	The area that has been prepared to allow for a drilling rig to work.
Wet gas	Gas that contains less methane and more ethane and other complex hydrocarbons that may condense (see condensate) at atmospheric conditions.
Workover	The restoration or stimulation of a production well to restore, prolong or enhance the production of oil and/or gas.

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