



australian petroleum production & exploration association limited

QUEENSLAND GAS: end-to-end water use, supply and management

2018

the voice of Australia's oil and gas industry



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Executive summary

The Australian Petroleum Production and Exploration Association (APPEA) is the peak body representing Australia's oil and gas explorers and producers. Our members account for nearly all of Australia's oil and gas exploration and production.

The oil and gas industry is a vital part of the Australian economy:

- supplying energy to 5 million households
- supplying the fuel for gas-fired generation in the electricity market
- supplying essential inputs to the manufacturing sector, underpinning 225,000 jobs
- investing more than \$200 billion in developing new supply for domestic and export customers
- paying more than \$9 billion in taxes and resource charges to governments
- employing tens of thousands of Australians in highly skilled, highly paid jobs
- generating \$25.5 billion in export earnings — adding almost 0.5 per cent to annual GDP growth.¹

Water is one of Australia's most precious assets. Industry recognises its responsibilities to protect that natural asset for other users today and for future generations. The industry's use of water is relatively modest—less than 0.2 per cent of the water consumed by Australians (by comparison, agriculture accounts for almost 59 per cent of water consumption).

The onshore oil and gas industry is subject to stringent regulation and scrutiny, far more so than other industries with comparable or greater consumption of water. The possible impact of industry activities on water resources is monitored closely by government agencies. In Queensland, the onshore industry has strict obligations to 'make good' impacts on the supply of water to landowners; such impacts have been limited to a handful of local cases and have been readily addressed.

The oil and gas industry delivers an exceptionally high economic return from the water it uses. According to the Australian Bureau of Statistics, the gas industry's value-add is \$933 million Gross Value Add per gegalitre of water used, compared to \$4 million for agriculture, \$37 million for aquaculture and \$83 million for wood, pulp and paper.

Regional communities benefit the most from the onshore industry, with new jobs and infrastructure creating stronger, diversified regional economies. In places, such as the Western Downs, the resources sector (including the natural gas industry) has become the largest contributor to gross regional product. Research by the CSIRO and the Department of Industry, Innovation and Science confirms a very positive social dividend in regions

¹ EnergyQuest (2017) EnergyQuarterly December 2017. Access at: <http://www.energyquest.com.au>; Reserve Bank of Australia *Statement on Monetary Policy*, August 2017, p33.

which host the industry, including low unemployment, higher family incomes, a reversal of population decline, more employment opportunities for women and higher levels of youth education.

In the case of Queensland coal seam gas projects, the industry is more of a supplier than a user of water. Most water removed from coal seams as a by-product of gas production is treated and provided at low cost to other users such as farmers and local government or used to recharge aquifers. Industry in Queensland has invested more than \$3 billion in water treatment infrastructure, and over 40 gigalitres of water was provided by the industry for beneficial use in 2016–17 with 83 per cent of this volume used for irrigation. This supply of water is particularly important where drought conditions exist. About one-quarter of the water removed from local coal seams is returned to aquifers.

All water in the natural environment contains some level of salt. The level of salt in groundwater can be low enough for water to be considered 'fresh' or high enough to be saltier than seawater. Use of water with moderate or high levels of salinity can have detrimental effects on agricultural land and the environment, and so the effective management of brine and salt is a key consideration for all activities that use groundwater.

This report summarises:

- 1** The social, economic and environmental impacts and benefits of the petroleum industry's take and use of water.
- 2** How communities are benefiting from desalinated water provided by the industry.
- 3** How Queensland's gas industry is managing the brine and salt that is a by-product of providing desalinated water to communities for beneficial use.
- 4** The work undertaken to assess the feasibility collaborative and alternative long-term solutions to salt management.
- 5** The factors that influence the feasibility of available management options.

To date over \$100 million has been expended by the industry in undertaking joint and company-based investigation and analysis into the feasibility of salt management options considering technical, environmental, social and economic implications of these options. New opportunities, technologies and partnerships with other industries and/or government will be examined as they arise.

The industry remains committed to maximising water supply to communities and implementing an optimal long-term management solution for brine.

2 Social, economic and environmental impacts and benefits

- The petroleum industry uses water as a direct input to the process of producing petroleum.
- Developing these resources is vital to Australia. Petroleum products, from gasoline to plastics, are integral to our everyday lives.
- Petroleum is the raw feedstock for many chemical products, including pharmaceuticals, solvents, fertilisers and pesticides on which we rely.
- Australia's \$28 billion per year oil and gas industry contributes 58 per cent of Australia's primary energy, 2.5 per cent of Australia's gross domestic product, and almost \$9 billion in direct tax payments.
- The petroleum industry uses water efficiently, generating significant value add for the wider Australian economy.
- Further development of natural gas can have significant climate benefits, reducing emissions intensity.

Petroleum is essential to the Australian economy and way of life. As well as generating \$25.5 billion in export earnings the industry supplies an essential energy and commodity resource.

Almost half of Australian homes—five million households—are connected to the natural gas network. In NSW and Victoria alone, 2.3 million homes are connected. Gas accounts for 44 per cent of household energy use, with more than 11 million residential gas appliances in use.²

Petroleum and refined and derived products are used to power our cars, to provide energy and support manufacturing. Oil is the largest single energy source in Australia and accounts for close to 40 per cent of total energy end use.³ Australia's reserves of liquid fuels are declining, with an increasing proportion of these products being imported.

Natural gas is indispensable to many manufacturing processes. Gas is used to produce non-ferrous metals (such as aluminium, copper and zinc), chemicals and polymers (such as fertilisers and anti-freeze), plastics and non-metallic mineral products like glass, ceramics, cement and bricks, and is also used in food preparation, processing and packaging, fermentation and brewing.

² Deloitte Access Economics (2016), *Analysis for Gas Vision 2050*.

³ Australian Government (2016), *Australian Energy Statistics* <https://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/>

APPEA estimates about 225,000 jobs in the manufacturing sector rely on natural gas. Manufacturing clusters dependent upon gas are found in all Australian states.

Until recently, the demand for natural gas has been met from 'conventional' gas reserves (for example, the Cooper, Gippsland and Carnarvon basins). However, in eastern Australia, production from these established conventional sources has peaked. New conventional gas projects, such as the \$5.5 billion Kipper-Turrum project, are underway but will only partly replace lost output.

Fortunately, the last decade has seen a new and growing source of supply created—the coal seam gas reserves of Queensland. The potential of coal seam gas was identified in the 1990s. However, technical challenges and production costs higher than established conventional sources prevented its large-scale development. The opportunity to use coal seam gas as the feedstock for liquefied natural gas (LNG) exports changed the equation, drawing in an unprecedented \$70 billion in investment to unlock the resource.

Today, Queensland's unconventional gas reserves are the largest source of natural gas in eastern Australia. More than half of the gas consumed on the east coast is coal seam gas from Queensland; almost 90 per cent of gas reserves on the east coast are unconventional gas.⁴

The LNG industry has not only created its own supply—it has created much of the new supply flowing into the domestic market.

Queensland's oil and gas industry employs an estimated 27,000 people, generates more than \$9 billion in value added activities, including \$2 billion in annual associated salaries. Average earnings in the industry are over \$150,000 per annum, double the Queensland average.⁵

Over the last two financial years, \$15 billion of industry investment has helped sustain 3100 Queensland businesses; most of these businesses (more than 80 per cent) are based in regional areas such as Gladstone, Callide, and Maranoa.

The industry has a relatively small physical 'footprint' which limits its impact on traditional rural industries. Access to land is negotiated under a regulatory framework which seeks to minimise impacts and ensures fair compensation for landowners. There are 5861 conduct and compensation agreements signed with Queensland landowners who have received \$387 million in co-existence payments from 2011 to 2017.

Regional communities and other local industries are sharing the benefits of the infrastructure funded by the gas industry. For example, renewable energy projects are connecting to new power infrastructure built to serve gas projects. Farmers now have access to new supplies of treated water for irrigation, lifting productivity and farm incomes.

In eastern Australia, time is running out for the development of new gas resources in time to replace declining output from existing fields. Independent analysis by McKinsey and partners indicates that \$50 billion may be required to fund new supply to 2030. McKinsey warns that a failure to make timely investment in new supplies will create tight supply and push up prices.⁶

4 EnergyQuest (2017) *Energy Quarterly September 2017 Report*. <http://www.energyquest.com.au>

5 Lawrence Consulting (2017) Queensland LNG Economic Contribution Report, prepared for APPEA.

6 McKinsey and Company (2017), *Meeting Australia's Gas Supply Challenge*, <https://www.mckinsey.com/featured-insights/asia-pacific/meeting-east-australias-gas-supply-challenge>.

2.1 Essential for Australian manufacturing

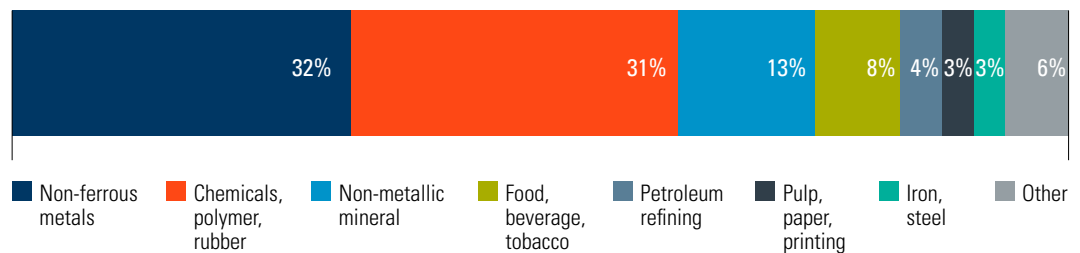
Natural gas is both a source of energy and an essential raw material (feedstock) for manufacturing. Almost one-third of the gas consumed in Australia is used by manufacturers.

About 225,000 people work in manufacturing sectors that rely heavily on gas; another 500,000 people work in related industries. The main industrial uses of natural gas and gas-derived products are producing:

- non-ferrous metals (e.g. aluminium, copper, zinc, tin)
- chemicals and polymers (e.g. fertilisers, anti-freeze)
- non-metallic mineral products (e.g. glass, ceramics, cement, bricks)
- plastic packaging for foods and beverages.
- Gas is also needed in food preparation and processing, fermentation and brewing.

Gas is second only to oil as an energy source for manufacturing. Gas is essential for many industrial processes, especially processes requiring high temperatures.

Figure 1: Gas — powering industrial processes



SOURCE: 2015 AUSTRALIAN ENERGY STATISTICS

2.1.1 Gas—the invisible ingredient of everyday products

Natural gas is also a raw material (feedstock) for creating products such as fertilisers, explosives, paper, plastics and chemicals. In most cases, there is no substitute for gas. Gas is used to produce ammonia, which is an important feedstock for several industries. The most commonly used fertiliser in the world is urea, which is produced from ammonia.

Producing each tonne of urea requires 21 gigajoules of natural gas—the same amount of gas that the average NSW household uses in a year. Australian industries use 1.6 million tonnes of urea each year.

Ammonia is also used to make explosives and cleaning products, and in fermentation, brewing and winemaking.

The plastics used in food packaging, plumbing, guttering, fibres, textiles, machine parts and a host of other applications are made from ethane derived from natural gas.

2.2 Climate benefit of natural gas

The International Energy Agency, the Climate Change Authority and most independent experts agree that the world will and should be using *more* gas in the transition to a low-emissions economy.

Gas-fired generation offers reliable, on-call and low emissions power. The emissions intensity of gas-fired plant can be as low as one-third of coal-fired plant. Experience in the United States shows how the substitution of gas-fired generation for coal-fired generation can slash emissions without jeopardising reliable, affordable supply. The US Energy Information Administration (EIA) reports that the shift to gas-fired generation accounts for 63 per cent of the 12 per cent reduction in US energy-related CO₂ emissions during the last decade.⁷ This shift has prevented 1.5 billion metric tons of carbon dioxide being emitted from power plants in the United States.

Australia has a similar opportunity to meet our energy needs while reducing emissions.

Gas-fired generation technologies can slash greenhouse gas emissions by 55 per cent compared to the National Electricity Market (NEM) average, and by 68 per cent compared to current brown coal generation technologies and 61 per cent compared to current black coal generation technologies.⁸

The on-call nature of gas-fired generation means it is ideally suited to 'firm up' intermittent renewable energy as well as to respond to surges in electricity demand. International research shows that the increasing penetration of renewable energy in OECD countries between 1990 and 2013 has been facilitated by fast-reacting, gas-fired generation.⁹

Australians have seen how gas-fired generation underpins energy security. The Australian Energy Market Operator made this point clear. *The 2017 Gas Statement of Opportunities* begins with the statement: 'Gas-powered generation is vital to continued security of electricity supply as the National Electricity Market transitions to lower emissions targets.'¹⁰

Numerous reports have shown that natural gas has a critical role to play in a low-emissions future as both a replacement for coal and a partner for renewables. For example:

- Modelling for the Climate Change Authority's August 2016 *Special Review on Australia's Climate Goals And Policies*, found under its preferred policy option that Australia must triple its use of gas in electricity generation by 2030 if we are to achieve our emissions reduction targets.¹¹
- The December 2016 Preliminary Report of the Finkel Review stated: 'Gas has the potential to smooth the transition to a lower emissions electricity sector' and 'The need for greater gas supplies for electricity generation is increasingly urgent.'¹²

7 US Energy-Related Carbon Dioxide Emissions, (2015) <https://www.eia.gov/environment/emissions/carbon/>

8 Commonwealth of Australia, (2016), *Preliminary Report of the Independent Review into the Future Security of the National Electricity Market*, p63, <https://www.energy.gov.au/sites/default/files/independent-review-future-nem-prelim.pdf>

9 Verdolini, Vona and Pop (2016), *Bridging the Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion?* <http://www.nber.org/papers/w22454>

10 AEMO, (2017) 2017 Gas Statement of Opportunities (p 1) http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf

11 Climate Change Authority, special review on Australia's climate goals and policies (2016), <http://climatechangeauthority.gov.au/sites/prod.climatechangeauthority.gov.au/files/files/Special%20review%20Report%203/Climate%20Change%20Authority%20Special%20Review%20Report%20Three.pdf>

12 Dr Alan Finkle AO, Independent Review into the Future Security of the National Electricity Market, (2016) <https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-prelim.pdf>

- The May 2016 *Final Report of South Australia's Nuclear Fuel Cycle Royal Commission* highlighted the critical role of cleaner-burning natural gas in the low-carbon economy of the future, including as a partner for renewable energy. It found 'Gas-fired generation plays a significant role in providing reliable supply under all future low-carbon scenarios for the electricity sector.'
- The November 2015 *Australian Power Generation Technology Report* provided a thorough, independent assessment of renewable, coal and gas technologies. It found gas-fired generation is cleaner than coal, cheaper than renewables and can adapt quickly to meet changing demand.

2.3 Community benefit

Regional communities benefit the most from the onshore industry, with new jobs and infrastructure creating stronger, diversified regional economies.

In places, such as the Western Downs, the resources sector (including the natural gas industry) has become the largest contributor to gross regional product. Research by the CSIRO and the Department of Industry, Innovation and Science confirms a very positive social dividend in regions which host the industry, including low unemployment, higher family incomes, a reversal of population decline, more employment opportunities for women and higher levels of youth education.¹³

In Queensland, an analysis of the longitudinal contribution of the petroleum industry has proven an immense benefit including:

- approximately \$50.7 billion in direct spending to the Queensland economy over the period 2011–12 to 2016–17
- \$4.1 billion in wages and salaries to an average direct workforce (i.e. not including all contract workers who work on mine sites) of approximately 4685 fulltime resident employees, representing an average salary level across the sector of approximately \$147,146 per annum.
- \$46.5 billion in purchases of goods and services from local over 3400 local businesses (including contract payments), community contributions and payments to local government (including rates, developer contributions and other payments) and state government (including royalties, stamp duty, payroll tax and land tax).

The industry has always regarded the support of local communities and the informed consent of landholders as essential to the long-term partnerships that enable our activities to be successfully conducted.

Many reputable and independent studies have identified significant positive regional socio-economic benefits of onshore gas and resources production. Community attitudes to the industry have also generally been found to be positive. Research confirms that the resources industry is most supported in areas where it operates

¹³ Office of the Chief Scientist, Department of Industry, Innovation and Science; GISERA (2015) *Review of the socioeconomic impacts of coal seam gas in Queensland*. https://www.industry.gov.au/sites/g/files/net3906/f/June%202018/document/pdf/review_of_the_socioeconomic_impacts_of_coal_seam_gas_in_queensland.pdf.

- The Australian Government's Bureau of Resource and Energy Economics (BREE) reported in 2015 that there are long term net economic benefits from CSG and negligible impacts of water and air quality to date.
- The CSIRO reported in 2013 that the CSG industry is contributing to poverty reduction, increasing employment and family income, and that there is a growing youth population in regions with CSG development.
- A 2013 study by KPMG showed that resources developments are not only making regions more prosperous, but also making their communities more stable and socially sustainable.
- A 2014 report by the CSIRO found that the majority of the community in Tara, Chinchilla, Miles, and Dalby accept, approve, or embraces the industry with only a small minority rejecting the industry:
- A 2018 social impact assessment for gas development in the Northern Territory found community concerns and threats can be mitigated and managed. They also identified significant opportunities for the enhancement of social values, such as collaboration between the community and industry, increased training and employment opportunities, better infrastructure, and indigenous participation.¹⁴

In addition to the broader socioeconomic benefits that come with increased economic activity and a more diverse regional economy, Queensland's natural gas and LNG industry has made significant public investments in the communities within which it operates. More than 220 different community organisations, based primarily in rural areas, received support from the industry.

2.4 Fiscal contribution

Oil and gas production in Australia is subject to numerous layers of taxation, including income (company) tax, GST and numerous other fees and charges (at a federal, state/territory and local government level). The industry is also subject to a variety of resources taxes, including petroleum royalties and the petroleum resource rent tax (PRRT). No other fuel in the energy market is subject to an additional, profits-based tax like the PRRT.

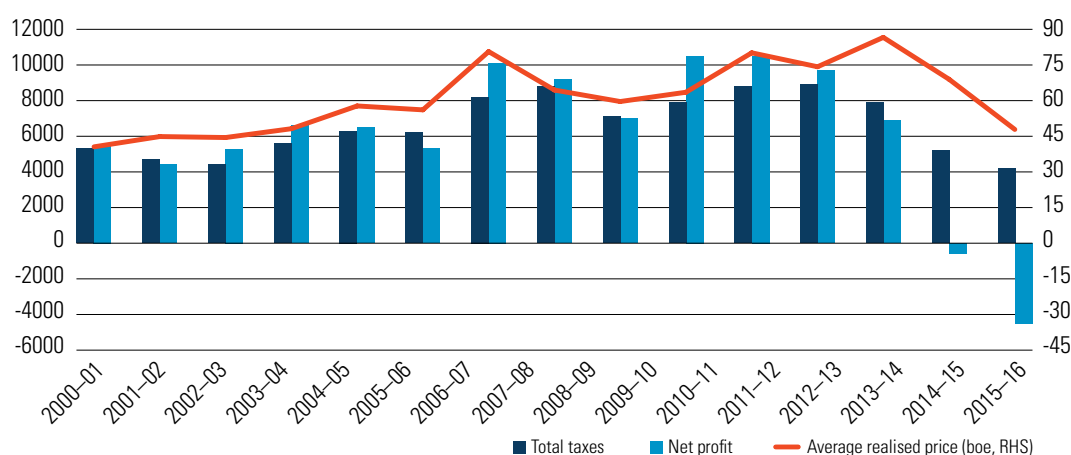
Company tax is levied at a corporate level, while resource taxes are generally applied at a project or production licence level. In terms of resource taxation:

- States and the Northern Territory levy royalties on onshore production (both from conventional and unconventional sources) and from offshore production in state/territory waters.
- Commonwealth crude oil and condensate production excise and Commonwealth petroleum royalty applies to production sourced from licences derived from Offshore Exploration Permits WA-1-P and WA-28-P (including the North West Project). Commonwealth crude oil and condensate production excise also applies to crude oil and condensate production from areas under state and territory jurisdiction.
- PRRT applies to production (conventional and unconventional) from all projects (offshore and onshore).

¹⁴ Coffey (2018), Beetaloo sub-basin Social Impact Assessment Case Study <https://frackinginquiry.nt.gov.au/inquiry-reports?a=476739>

Before 2014–15, taxes and resource charges on average accounted for about one half of the oil and gas industry’s pre-tax profit. Put simply, governments received close to 50 cents in every dollar of industry profit. Reflecting the significant fall in commodity prices since late 2014 (together with the peak in spending associated with new gas projects) the industry recorded a net operating loss of \$0.6 billion in 2014–15 and another loss of \$4.5 billion for the year 2015–16. Despite these losses, the industry’s total tax payments remained strong—estimated at \$4.3 billion for 2015–16 (compared with \$5.2 billion in 2014–15). The industry’s overall return on assets was estimated at -1.3 per cent, based on a total asset value of \$345 billion.

Figure 2: Oil and gas industry net profit, tax contribution and average prices realised: 2000–01 to 2015–16.



SOURCE: APPEA FINANCIAL SURVEY (2017)

2.5 Petroleum royalties

Each state and territory collects royalties on the production of oil and gas (from conventional and unconventional sources). Royalties are generally assessed as a percentage of the wellhead value of production. The wellhead value is calculated by subtracting the cost of transportation and processing involved in bringing the raw products from the wellhead to a point at which marketable products are sold. Royalties are generally assessed on a licence area basis.

Allowable deductions when determining the wellhead value include some post-wellhead production costs, including certain treatment, transportation and storage expenses and eligible depreciation and operating expenses. Most jurisdictions levy royalties at a rate of 10 per cent of the wellhead value.

The petroleum royalty paid depends on a range of factors, including costs and the level of production. As the sales price is critical to the wellhead value, movements in oil and gas prices significantly affect royalty payments. The Queensland Government has forecast petroleum royalty collections of \$296 million in the year 2020–21 (see below).

2.6 Petroleum Resource Rent Tax

PRRT is a profits-based resource tax applying to all oil and gas projects in Australia. It is levied by the Commonwealth under the *Petroleum Resource Rent Tax Assessment Act 1987*. A liability to pay PRRT arises after a project has recovered all eligible project costs and achieves a modest, risk-adjusted rate of return.

PRRT was introduced in the mid-1980s for new offshore projects. In the early 1990s the regime was expanded to cover the Bass Strait project. From 1 July 2012, the PRRT was extended to all onshore petroleum production, including unconventional gas. For onshore oil and gas projects (captured by the 2012 extension), the then existing resource taxes and charges that applied at the time of the extension have been fully retained.

PRRT is a profits-based tax:

- It is assessed on an individual project basis—a project may comprise one or more petroleum production licences.
- A tax rate of 40 per cent applies.
- A liability is incurred when all allowable expenditures have been deducted from assessable receipts.
- Assessable receipts include the amounts received from the sale of all petroleum.
- Deductions include capital and operating costs relating to the petroleum project. These are deductible in the year they are incurred. Deductible expenditures include those related to exploration (including eligible exploration costs incurred by a taxpayer in other areas), development, operating and closing down activities.
- Costs associated with the liquefaction of gas and storing and shipping LNG are outside the scope of the tax—a 'marketable petroleum commodity' exists before these processes occur.
- Undeducted expenditures are compounded forward at a variety of set rates depending on the nature of those expenditures and when they are incurred.

Other resource taxes and charges (including royalties) incurred in relation to a project are rebateable against a project's PRRT liability. This avoids imposing double taxation on projects. Like other resource charges, PRRT is deductible in determining a taxpayer's income tax liability.

The PRRT a project pays is determined by numerous factors, including:

- A tax liability under the PRRT regime is incurred once a threshold return has been generated. As such, PRRT is unlikely to be paid from a project until many years of production.
- Other resource taxes and charges from a project (such as state and federal royalties and production excise) can be rebated against a PRRT liability from the same project.
- As PRRT is a profits-based tax, a tax liability depends on factors such as commodity prices, exchange rates and project costs. This is a design feature of the regime, and reflects the high rate of tax that is applicable when a tax liability is incurred.

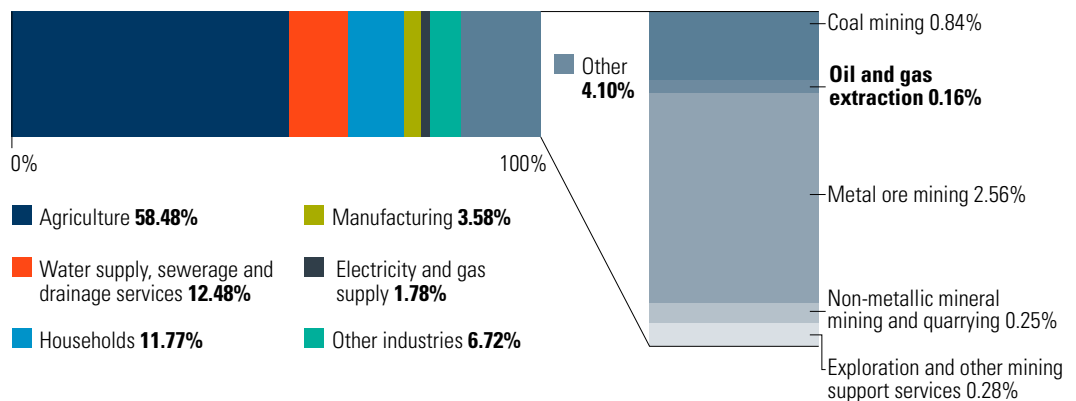
2.7 Volume of water used in oil and gas

The oil and gas industry uses very little water, relative to other industries.

During 2015–16, an estimated 76,544 gigalitres of water was extracted from the environment to support the Australian economy across all sectors. The main user of water is agriculture which consumed 9604 gigalitres of water.¹⁵

The broad extractive industry sector (i.e. mining, mineral processing, oil and gas) accounted for about 4 per cent (661 gigalitres) of water use in 2015–16. The oil and gas industry used just 26 gigalitres or 0.16 per cent of total Australian water consumption (see Figure 3)

Figure 3: Water consumption by industry and disaggregated mining sector, 2015–16 (%)



SOURCE: ABS

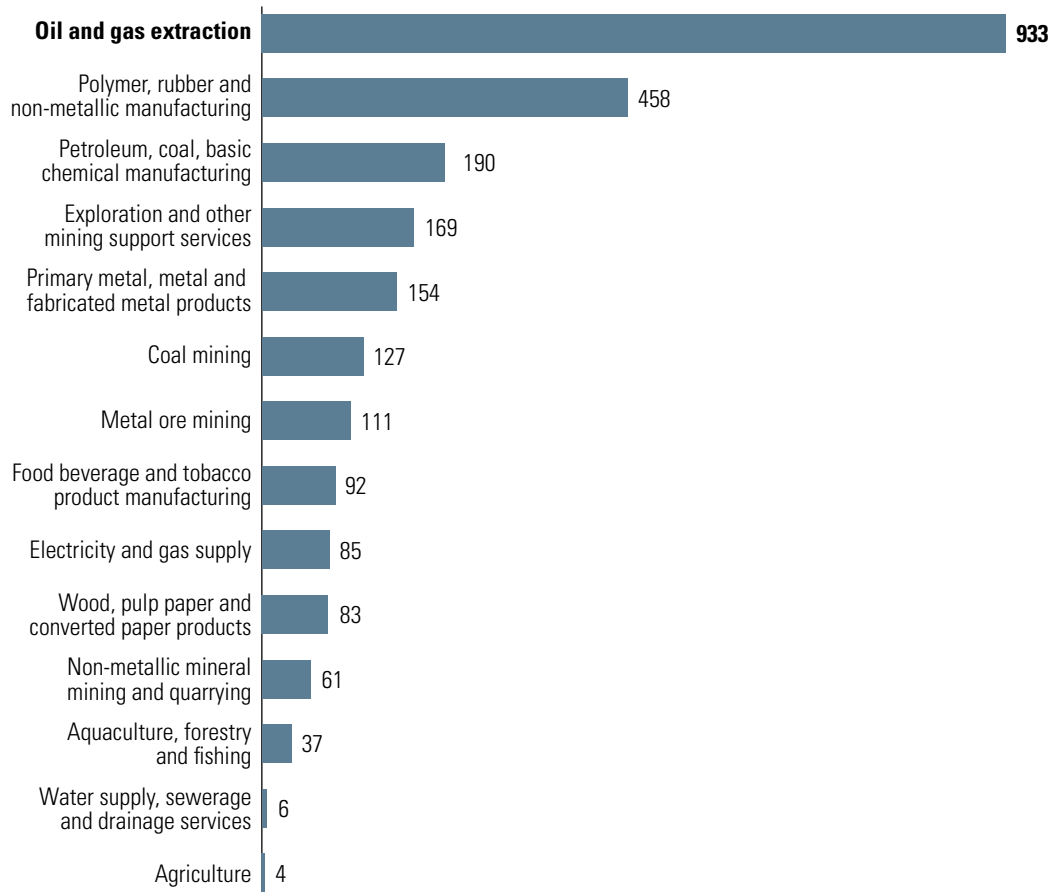
2.8 High economic value of water use

The water used by the oil and gas industry generates an exceptionally high economic value-add.

Value added measures the value of the end product compared to the water used in its production—calculated as millions of dollars per gigalitre of water. According to the Australian Bureau of Statistics, every gigalitre of water consumed by the oil and gas industry generates over \$933 million of value. This return is extremely high compared to other large water users; \$127 million per gigalitre in coal mining, \$37 million in aquaculture and just \$4 million per gigalitre for agriculture (see Figure 2).

¹⁵ Australian Bureau of Statistics, (2017) *4610.0 Water Account 2015–16*. www.abs.gov.au

Figure 4: Industry gross value added per GL of water consumed¹⁶



SOURCE: ABS

2.9 How water is used in the oil and gas industry

- Water is used in all stages of an oil and gas project from exploration to development. Water is used for well drilling, field development, infrastructure and construction, hydraulic fracturing, and other activities.
- The volume and type of water used is highly dependent on the geology and requirements of a field.
- The oil and gas industry is also a water provider to local users, treating the water associated with gas production and supplying it to farmers, local governments and other users.

The petroleum industry uses surface and groundwater sources. Operations such as drilling depend on access to groundwater.

Petroleum projects have three primary phases: exploration, development and production. Each stage has a different use of water depending on the type of petroleum development, project size, and location.

¹⁶ Australian Bureau of Statistics (2007), *An Experimental Monetary Water Account for Australia*, Cat. No. 4610.0.55.005, August.

Petroleum operations also produce water which is brought to the surface along with hydrocarbons (see Produced formation water). In the case of coal seam gas, water is also a by-product of production, with a significant volume of water treated and then made available to farmers, local government and other users.

A significant volume of water in Queensland is also treated to improve its quality from stock water to drinking water standards, then reinjected into Great Artesian Basin aquifers, increasing the water pressure in these aquifers and storing water for use by current and future generations.

Water can be used in petroleum operations to increase reservoir pressure and enhance the recovery of oil and gas. Table 1 below describes the relative water demand at each stage of the project lifecycle for different developments. The duration of each step varies across projects.

Table 1: **Water and the development cycle**

	Exploration	Development	Operations
Conventional	Low water demand	Low water demand	Typically low water use, potential to use water for enhanced recovery
Coal seam gas	Low water demand for drilling, hydraulic fracturing may or may not be required	More wells, camp supply, construction, dust suppression	Low water demand
Shale/tight gas	Few wells, low water demand, hydraulic fracturing may be required	Hydraulic fracturing (predominantly), construction, dust suppression, camp supply	Low water demand

2.9.1 Exploration

Exploration for oil and gas resources starts with geological and geophysical surveys to identify areas of interest. As water is only required for human consumption and vehicle use, impacts are negligible.

2.9.2 Oil and gas development

Where a commercial resource is located, a well is used to flow oil and gas to the wellbore. Any pressure in the reservoir above hydrostatic pressure will cause fluids or gas to flow up the wellbore. If the pressure is not sufficient the resource may be pumped or lifted.

Typically, gas occurs under pressure within the reservoir and will flow into the wellbore and then to the surface. In conventional reservoirs the gas can easily flow through the reservoir-rock pore spaces towards the wellbore. Unconventional reservoirs may need additional stimulation treatment to increase this flow.

As the field matures, secondary recovery (also called enhanced recovery) may be employed. In some cases, fluids (e.g. water) may be pumped into the ground to increase pressure and properties to release additional hydrocarbons. This technique has been employed in Australia.

2.9.3 Water found in oil and gas reserves (produced formation water)

Water present in the geological formations where oil and gas resources are found is called *produced formation water* (PFW) or, in coal seams, *associated water* (see below). This water is brought to the surface along with oil or gas and varies in quality and quantity from field to field. Natural gas arriving at the surface will contain water vapour, which is the main source of produced water in conventional gas fields.

PFW is made up of a range of components and may include petroleum hydrocarbons, suspended solids, dissolved oxygen and salt.¹⁷ The volume and properties of produced formation water vary from location to location and over the productive life of a reservoir (for example the oil-to-water ratio decreases over time).

The disposal of PFW is highly regulated and managed in Australia. Industry uses a range of techniques to minimise, reuse and recycle, and treat PFW:

- Minimising PFW: dual completion wells (downhole water sink), mechanical blocking devices, downhole separators, subsea separation, etc.
- Reuse and recycle: underground injection, irrigation for crops, industrial use, dust control, etc.
- Treat: Treated then managed according to state regulations.

2.9.4 Water used in drilling

Water is consumed in well drilling. The amount of water used depends on how many times the mud is reused in different wells and the lifetime production of each well. In Australia, the general rule of thumb for onshore wells is approximately 1 ML per well for drilling. Drilling muds are expensive to produce, so they are constantly recirculated in the well and recycled for use in other wells.

2.9.5 Water used in enhanced recovery

Enhanced Recovery (or secondary production) generally refers to maintaining reservoir pressure to sustain economic rates. At this point, new wells can be drilled to inject water (or other fluids) into the reservoir. Enhanced recovery is generally deployed in conventional oil extraction activities.

The injection well is positioned some distance from the production well, with the position chosen based on an understanding of the reservoir characteristics. The injection water may be obtained from seawater, reuse of produced water, from purpose-drilled brackish water wells, from freshwater sources or from municipal wastewater sources. Seawater is typically used offshore, or at onshore sites near the coast.

Australia's Barrow Island Windalia reservoir is Australia's largest onshore Enhanced Recovery project and was developed in the late 1960s. It is estimated that using water to manage the field pressure effectively reduced the field decline rate from approximately 18 per cent per annum to less than 2 per cent—adding millions of barrels in recovery and years to productive field life.¹⁸

¹⁷ Swan et al, Environmental implications of offshore oil and gas development in Australia, 1994.

¹⁸ Hartanto Lina, Widjanarko Wisnu, Muna Diala (2011) The success story of Windalia waterflood optimisation through integrated asset management in a mature field. *The APPEA Journal* 51, 726–726. <https://doi.org/10.1071/AJ10106>.

2.9.6 Water used in hydraulic fracturing

Oil and gas can be produced from reservoir rocks that have very low permeability by hydraulic fracturing. In hydraulic fracturing treatments, a fluid is pumped at high pressure down a wellbore to initiate and propagate cracks in the low permeability rock.

The fluid is a water-based mixture containing sand or other solids, called proppants, that can prop open the newly created fractures. The amount of water used in hydraulic fracturing varies depending on resource and the amount of stages required. The source of water for hydraulic fracturing is an important consideration for industry, particularly in new and remote field locations.

2.9.7 Hydraulic fracturing

Hydraulic fracturing injects water-based fluids at high pressure into rock formations deep underground to create tiny fractures that enhance the flow of oil and gas. The process has developed over more than 65 years and has been applied to millions of wells around the world, including more than 1500 wells in Australia since the 1960s. Hydraulic fracturing is also used in renewable (geothermal) energy production and to enhance the productivity of water bores.

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

In Queensland, around 6 per cent of all wells have been hydraulically fractured, without incident. In the Cooper Basin in South Australia, some 40 wells have been hydraulically fractured over the last two years. Hydraulic fracturing in the Cooper Basin has occurred for many decades without incident. In Western Australia, hydraulic fracturing has been used extensively to assist with the recovery of oil and gas from conventional resources—an estimated 800 wells have been hydraulically fractured since 1958, without incident.¹⁹

Since the 1970s, fracking has been used to produce oil from the Class 'A' Nature Reserve of Barrow Island.

2.9.8 Associated water

Associated water refers to the water that naturally exists in petroleum formations. Coal Seam Gas is adsorbed to the coal matrix by the hydrostatic water pressure. The removal of water in the coal seam reduces the pressure, enabling the gas to be released from the coal. More information on associated water from coal seam can be found in Appendix 1: coal seam gas and associated water.

¹⁹ Department of Mines and Petroleum (2017), Gas Fact Sheet: Hydraulic Fracture Stimulation, Government of Western Australia, <http://dmp.wa.gov.au/Petroleum/Hydraulic-fracture-stimulation-20018.aspx>.

3

Conservation and protection of water

-
- Conservation and protection of groundwater and surface water is a high priority during all oil and gas activities.
-
- All surface activities that could potentially affect water resources are regulated and controlled.
-
- Studies and decades of experience show the risk of groundwater and surface water contamination is very low.
-
- When a well reaches the end of its life, it is decommissioned (plugged and abandoned). This is done to a high standard to ensure long-term containment and isolation from geological formations.²⁰
-

Conservation and protection of groundwater and surface water is a major priority during all oil and gas activities.

The use of chemicals during drilling, cementation and hydraulic fracture stimulation of wells is controlled, strictly regulated and managed to minimise environmental risk. Studies and decades of experience show the risk of groundwater and surface water contamination is very low.

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

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

The oil and gas sector is committed to ensuring that its impacts on the environment are minimised. To ensure the adequate protection of groundwater it is common practice that operators use a number of risk mitigation measures, including robust well construction, safe handling and use of chemicals and extensive environmental monitoring.

Ensuring that well integrity is maintained throughout the life of operations is critical to safety and the protection of the environment. Wells are routinely inspected and subjected to maintenance. The industry is committed to monitoring and fixing any wells that are not functioning to the standards required.

²⁰ Report into the shale gas well life cycle and well integrity, CSIRO. December 2017.

All surface activities that could potentially affect water resources (such as drilling, construction, transport etc) are strictly regulated and controlled. The management of chemicals and materials on the surface are not unique to the oil and gas industry and comprehensive regulation and risk management is in place.

3.1 Water management

Water management is an essential component of oil and gas operations. Although the volume of water used by the oil and gas industry is considerably lower than in the agriculture, power and many other sectors, oil and gas operations do involve the handling and management of produced water, wastewater and rainfall run-off.

There are a number of industry practices which mitigate and reduce the risks of petroleum activities damaging water quality and quantity. These include:

- detailed well design, testing and monitoring during all stages of well construction, hydraulic fracture stimulation, production testing, suspension, development and decommissioning
- monitoring local weather and climate information to make informed decisions regarding site operations
- ensuring site environmental inductions for all site personnel and contractors include protective measures to prevent avoidable discharge into, or contamination of, waterways, groundwater or established drainage systems
- ensuring appropriate storage of fuel and other flammable and combustible liquids in accordance with 'AS1940:2004 The storage and handling of flammable and combustible liquids'.
- maintaining stormwater containment systems
- having a procedure in place to manage large quantities of water (e.g. pumping to an existing dam or watering point)
- regular inspection and integrity checks of flowback tanks
- all access roads, culverts and creek crossings maintained in proper working order
- ensuring adequate freeboard is maintained in ponds to allow for a prolonged period of intense rainfall
- ensuring all pipes and hoses are in good condition and fit for purpose to minimise risk of leaks from pipe
- periodic inspections of the site's stormwater and waste water containment systems
- refuel and transfer chemicals at a distance from drainage lines
- ensure site is equipped with spill clean-up equipment
- ensure well control critical equipment and systems on stimulation equipment are fit for purpose, certified, maintained in good working order and tested as required
- ensure appropriate well control training/certification for rig personnel
- ensuring sufficient distance between exploration targets and aquifers
- continuous real-time pressure, rate and volume monitoring during fracturing stimulation to ensure an immediate response in the unlikely event a loss of containment occurs
- maintaining all waste water systems in working order to minimise impact on groundwater.

3.1.1 Protection of surface water

The management of water, chemicals and other substances on the surface is a key consideration for the oil and gas industry.

Proper handling of fluids that are returned to the surface is crucial. Once hydraulic fracturing fluids return to the surface, they are typically stored in tanks or lined pits to isolate them from soils and shallow groundwater zones. Most studies into hydraulic fracturing have found that, overall, surface spills of fracturing fluids pose the greater risks to water than hydraulic fracturing.

The risks associated with water and chemicals handling are common to many industries such as agriculture and transport. Possible sources of impact on water quality may include:

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

Oil and gas production involves use of fresh water, fracturing fluids, flowback water and produced water, chemicals and additives, as well as drilling muds and drill cuttings.

Best practice is to minimise the amount of these materials on site, contain materials as fully as possible, reuse or recycle to the greatest extent feasible, and dispose responsibly any residual materials offsite.

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

A recent study by the Department of Environment and NICNAS identified stringent protective measures imposed by state and territory and Commonwealth governments for the petroleum industry and found that the probability of a surface spill damaging water resources is very low and that 'we can be confident that it can be used safely'.²¹

3.1.2 Protecting groundwater

The risk of contamination of aquifers by drilling or fracture stimulation fluids is very low for numerous reasons, including:

- few coal seam gas wells require fracturing—only six per cent of the wells drilled in Queensland have required hydraulic fracturing;
- hydraulic fracturing fluids are 90 to 98 per cent water and sand. Additives make up a relatively small proportion of fluids; most additives are benign
- the few additives which could, in theory, present a potential risk to human health or the environment would need to be discharged in large quantities, over a long period, to reach concentration levels which could affect the much larger volumes of water present in aquifers. Such a scenario would require an exceptional failure of preventative measures to occur and continue undetected over a protracted period
- natural barriers—i.e. thick layers of impermeable rock separating aquifers and wellheads— isolate the point of fracturing from aquifers.

²¹ Department of Environment, (2017) National Assessment of Chemicals (p 11) <http://www.environment.gov.au/system/files/resources/03137f85-1bea-46a4-b9e7-67d985b4aeb5/files/national-assessment-chemicals-overview.pdf>.

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

A recent report by the CSIRO found that chemicals remaining underground after hydraulic fracturing are unlikely to reach people or groundwater dependent terrestrial ecosystems in concentrations that would cause concern. Risks are therefore likely to be very low. Risks from naturally-occurring chemicals in the coal seam mobilised by hydraulic fracturing are also likely to be very low for the same reasons.²²

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

1 Concentration and toxicity

While a number of additives are used in hydraulic fracturing, very few of these additives could pose a risk to the environment or human health. The additives used in hydraulic fracturing are well known and regulated by State governments. The additives used are placed hundreds of meters beneath the surface, in very low concentrations (much lower than those used in swimming pools). Risks at the surface relate to transportation, storage, and handling of chemicals which are common to all industries that use chemicals and are effectively managed by existing regulations.

2 Likelihood that the chemicals remain in the ground

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

3 Likelihood the chemicals will migrate to uncontrolled areas

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

3.1.3 Ensuring well integrity

Concerns around well integrity are often raised in relation to the potential for oil and gas wells to leak and cause water impacts.

An oil or gas well is a technically advanced bore hole that reaches hundreds to thousands of metres beneath the earth's surface to tap petroleum resources. In Australia, wells can vary in depth from 300 meters to 2000 to 4000 metres deep. For the industry, these are not challenging depths; overseas, wells beyond 10,000 metres are becoming common. Water wells for agriculture or domestic use are usually less than 100 metres deep.

Controlling the gases and liquids as they are brought to the surface relies upon long-term well integrity. Not only does the well have to contain the petroleum products inside the

²² CSIRO (2017) Deeper groundwater hazard screening for chemicals used in coal seam gas extraction— Overview, <http://www.environment.gov.au/system/files/resources/370d0bcd-8fe2-436f-88d7-1c3361ef8cd5/files/deeper-groundwater-hazard-screening-research-overview.pdf>.

well, it must also ensure that subsurface rock layers and any related aquifers penetrated by the well remain isolated from each other. Achieving all this requires high standards of well design and construction.

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

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

The most common well integrity risk is slow leakage of methane around the external casing, but the consequences of such leaks, although negative from a climate change perspective, do not threaten health because natural gas is not toxic, the frequency of substantial leaks is low, and the leakage rates are low as well.

3.1.3.1 Well casing ensures isolation of zones

Image 1: Well casing

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



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

- conductor casing—to secure the near surface section—soil and gravel etc—8⁵/₈" diameter
- intermediate casing—from surface down to the base of weathered or weak strata—6⁵/₈" diameter
- production casing—down to the top of the target formation—4¹/₂" diameter

All strings are cemented in place to isolate any aquifers.

3.1.3.2 Well cementing ensures well integrity

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

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

Image 2: Well casing and cementing

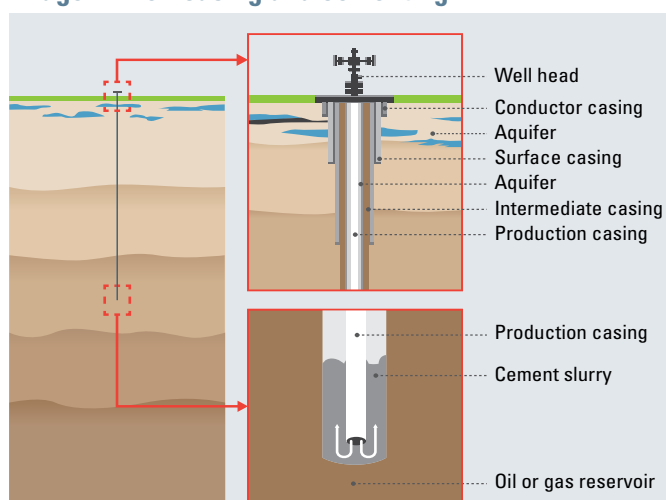
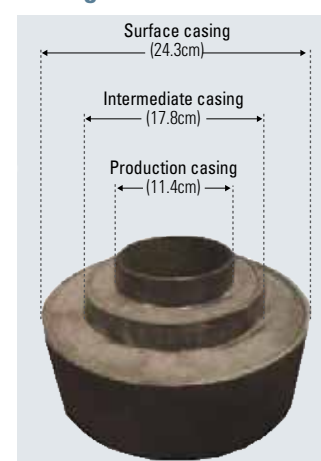


Image 3: Multiple pipe casings and cementation



3.1.3.3 Well failure is very rare

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

As described above there are multiple barriers in place to protect wells. The terms 'well failure' and 'well integrity' have sometimes been misunderstood.

A failure of a well barrier element will usually result in a well with reduced integrity. A reduction in well integrity does not necessarily mean any environmental impact. If a barrier has failed, there are actions that can be done to restore the failed well barrier (such as re-working the well). Failure of all barriers is called a 'loss of well integrity'. The obvious consequences of a loss of well integrity is blowouts or leaks that can cause material damage, personnel injuries, loss of production and environmental damage.

A single barrier loss is more common than a complete barrier loss. Studies indicate that wells are extremely unlikely to have barrier or well integrity failures when wells are constructed according to modern construction standards.²³

²³ Stone et al. 2016b.

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

The data²⁴ shows only 12 incidents in Ohio related to failures of (or graduate erosions to) casing or cement—a failure rate of **0.03 per cent**. In Texas, the failure rate was only about **0.01 per cent**. Obviously zero is the aim, but this is still a very low percentage considering the large number of wells drilled. A recent review by King and King (2013) of the data from 253,090 wells in Texas found that only four in every 100,000 (0.004 per cent) wells constructed to modern standards experienced a loss of well integrity, compared to 0.2 per cent for older wells.

The Queensland Gasfields Commission has released some information on well integrity in that state.²⁵ The cementing 'failure' rate after testing, remediation, and follow-up according to the Queensland code has been zero. The likelihood and therefore risk of a subsurface breach of well integrity is assessed to be very low to near zero.

- In July 2015, the Petroleum and Gas Inspectorate advised that, from 2010 to March 2015, 6734 CSG exploration, appraisal and production wells had been drilled in Queensland.
- According to the Petroleum and Gas Inspectorate, no leaks have been reported for subsurface equipment. This is consistent with recent scientific field measurements which found, in a sample of 43 wells '...no evidence of leakage of methane around the outside of well casings...' (Day et al, 2014: p2).
- There have been 21 statutory notifications (a rate of 0.3 per cent) under the well construction code concerning suspect downhole cement quality during construction.
- For all of these 21 notifications, the gas companies followed up with subsequent testing to assess well integrity and undertake any remedial work.
- The Petroleum and Gas Inspectorate followed-up on all 21 notifications to ensure that the tests, and any required remediation work, conducted on the well was successful before gas production commenced, with the company also having appropriate monitoring programs in place to ensure ongoing integrity of the well.

In 2015, the Western Australia Department of Mines and Petroleum (DMP) conducted a survey of 1035 non-decommissioned wells (both offshore and onshore wells) which found that: 'the vast majority of petroleum and geothermal wells are drilled, completed, produced and decommissioned without any adverse environmental impacts'.²⁶ DMP found that, of the 953 active petroleum wells surveyed, 9 per cent have had production tubing failures and 3 per cent have had production casing failures well away from aquifers, which were still protected by the surface and conductor casings. There have been no failures of surface or conductor casings.

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

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

26 S Patel, S Webster & K Jonasson, *Review of well integrity in Western Australia, Petroleum in Western Australia*, April 2015, p24.

3.1.3.4 Long term well integrity can be achieved

Once a well has reached the end of its useful life, it must be decommissioned and remediated (the common industry term is 'plugged and abandoned'). Steps taken to remediate a well are usually well defined by the relevant regulator. A typical well remediation uses a drilling rig to remove any equipment in the wells, such as subsurface pumps and pipe tubing. The rig then pumps cement into the well and sets mechanical plugs as a back-up, to create long-term barriers to fluid flow and isolate rock zones. Once this is done, the well-head is removed, and, in onshore wells, it is cut off below ground level so that past practices such as agriculture can resume over the well site.

A properly remediated well is very different to a producing well that needs regular measurement and monitoring. A remediated well is designed to be safe and pose no material threat to safety and the environment for future generations. The industry restores the natural integrity of the formation penetrated by the wellbore. This isolates permeable and hydrocarbon bearing formations are isolated to protect underground resources, prevent potential contamination of potable water sources and preclude surface leakage.

The claim that 'cement can't last forever' is often made by industry opponents to suggest that, over time, all plugged and abandoned gas wells will leak—causing contamination of groundwater.

Modelling and analysis into well corrosion show that a properly designed and implemented well can last indefinitely. Yamaguchi, Shimoda, Kato, Stenhouse, Zhou, Papafotiou, Yamashita, Miyashiro & Saito (2013) have investigated the long-term corrosion behaviour of cement in abandoned wells under CO₂ geological storage conditions by simulating the geochemical reactions between the cement seals over a simulated period of 1000 years. While alteration of the cement seals was found after a period of time, the alteration length after 1000 years was approximately one metre, leading to the conclusion that cement will isolate CO₂ and upper aquifers over the long-term.²⁷

Cement plug integrity in CO₂ subsurface storage was also assessed by Van der Kuip, Benefictus, Wildgust & Aiken (2011).²⁸ Using estimates for degradation after 10,000 years they likewise came to similar conclusions stating that 'mechanical integrity of cement plugs and the quality of its placement probably is of more significance than chemical degradation of properly placed abandonment plugs' (literature on corrosion and cement degradation considers CO₂ stored at high pressure to be more aggressive than methane).

3.1.4 Potential for hydraulic fractures to act as pathways for aquifer contamination

Concerns have been raised about the potential for hydraulic fracturing activities to reach water-bearing formations, overlying aquifers or nearby water bores.

Recent studies by the CSIRO and others have looked into the possibility of shallow groundwater being impacted due to hydraulic fracturing migration from deeper aquifers. Based on modelling studies, the authors concluded that the likelihood of hydraulic

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

28 MDC van der Kuip, T Benedictus, N Wildgust, T Aiken, *High-level integrity assessment of abandoned wells*, Energy Procedia, Volume 4, 2011, pp 5320–5326, www.sciencedirect.com/science/article/pii/S1876610211007922.

fracturing reaching a water resource is low when the vertical separation between the reservoir and the overlying aquifer is large and other natural pathways (such as faults or leaky wells) are absent.

CSIRO research also found that chemicals remaining underground after hydraulic fracturing are unlikely to reach people or ecosystems in concentrations that would cause concern. This conclusion is based on natural dilution and degradation that reduce concentrations to negligible levels. Risks are therefore likely to be very low.²⁹

3.1.5 Chemical management and water

The chemicals used in hydraulic fracturing are commonly occurring and used for a range of applications outside of oil and gas extraction.³⁰

In December 2017, the Australian Department of Environment and Energy (DoEE) and the National Industrial Chemicals Notification and Assessment Scheme (NICNAS) released an assessment of chemicals associated with coal seam gas extraction in Australia.

This study examined the risks to health and the environment from surface (above-ground) chemical spills. The NICNAS assessment focusses on what it describes as 'worst-case' scenarios, which are highly-implausible and assume that all the safety and handling precautions required by law are not used.

The NICNAS assessment found the most significant potential risk to public health and the environment was exposure to chemicals after a large-scale transport spill, a risk facing any industry that uses chemicals. The chemicals used for hydraulic fracturing in the CSG industry accounts for less than one hundredth of one per cent of chemicals transported by road in Australia. Extensive regulation of heavy vehicle movements and chemical storage already minimizes the risks identified.

Studies from the CSIRO and NICNAS have confirmed that the use of chemicals in the CSG industry poses little risk to the community or the environment.

In five technical papers, the CSIRO found that residual chemicals remaining underground after hydraulic fracturing are unlikely to reach people or ecosystems in concentrations that would cause concern and therefore risks are very low. The CSIRO studies are the latest independent research to again confirm that, properly regulated, hydraulic fracturing is safe.

29 CSIRO (2017) *Deeper groundwater hazard screening research* <https://www.csiro.au/en/Research/Major-initiatives/Unconventional-gas/CSG-chemicals>.

30 Department of Environment. What does fracking fluid contain? <http://www.environment.gov.au/system/files/pages/2d9f9167-3826-4d59-8be5-67c8c731fb59/files/what-does-fracking-fluid-contain-factsheet.pdf>.

4

Regulatory framework surrounding the industry's water use

-
- The oil and gas industry is one of the most highly regulated industries in Australia.

 - Under the Constitution the states and territory governments have primary responsibility for managing water resources

 - State governments that host activity have an established suite of legislation, regulation, and reporting requirements that apply to the oil and gas industry.

 - The Commonwealth has a role in facilitating a collaborative approach to water management, such as through COAG.

 - The Commonwealth regulates the oil and gas industry and water impacts under federal environmental legislation. However, there is no value in expanding the 'water trigger' to include other projects.
-

Water issues have long been managed under comprehensive approvals regimes at the state level. This constituted responsibility has required states to develop detailed assessment processes for the impacts of an activity on water resources and for water use. These processes require scientific, social and economic analysis of both surface and groundwater at both a local and regional scale to ensure potential impacts are understood, mitigated and managed. There was no justification that this system was broken and for the federal government to unilaterally override state governments.

The water used and produced by the Australian oil and gas industry is comprehensively managed and regulated. State and territory governments are primarily responsible for the management of water resources within their jurisdictions (see State government regulation for further detail). The federal government has a role in water management in certain circumstances under the *Environmental Protection and Biodiversity Conservation Act 1999* (EPBC Act). This includes water resources as they apply to coal seam gas projects (the water trigger).

The oil and gas industry accesses water for operations in strict accordance with the framework relevant in that jurisdiction. A summary of the arrangements as they apply to water is below. Further detailed information on the regulation that applies to the oil and gas industry can be found at Attachment 2: Government regulation by state.

4.1 Queensland Government regulation of water

Petroleum operations in Queensland are subject to a range of regulations and subject to stringent monitoring and compliance regimes.

The CSG industry's environmental and water management obligations are governed by a regulatory framework that includes elements of the *Environmental Protection Act 1994*; *Water Act 2000*; and the *Petroleum and Gas (Production and Safety) Act 2004*.

Under the Queensland regulatory framework, petroleum and gas tenure holders have a limited right for the extraction of groundwater in the process of producing petroleum and gas. The rationale for this authority is that petroleum cannot be produced without this water also coming to surface. New requirements have been introduced requiring non-associated water take to be measured and authorised.

Associated water can only be produced to the extent necessary to produce petroleum, and with this authority comes significant additional responsibilities that are not applied to other water users. These include, for example, requirements to monitor for impact, fund regional level modelling to forecast impacts, make good for any impacts on other water users, and limitations of how the water can be used that specify that water must be beneficially reused where feasible.³¹ More information is available from the regulator at <https://www.ehp.qld.gov.au/management/non-mining/water.html>.

Under Queensland's *Waste Reduction and Recycling Act 2011*, companies are also required to identify beneficial uses for produced water including treating the water for other uses such as irrigation, town water supplies, environmental flows and aquifer recharging.

To ensure a comprehensive cumulative groundwater assessment is completed and to provide clarity on the management responsibilities of individual tenure holders, areas with multiple tenement holders can be declared a 'cumulative management area' (CMA) under Queensland legislation.

Where a CMA is established, the Office of Groundwater Impact Assessment (OGIA) is responsible for undertaking assessments, establishing management arrangements and identifying responsible tenure holders to implement specific aspects of those management arrangements. The Surat CMA was established in April 2010 and the Surat UWIR 2016 took effect from 19 September 2016.³²

The Surat UWIR 2016 is a comprehensive regional groundwater flow model that was constructed to predict the impact of current and planned CSG development on groundwater pressures in aquifers. The model is the best available tool to assess regional groundwater impacts.

³¹ Queensland Government, Make Good Obligations. <https://www.ehp.qld.gov.au/management/non-mining/faqs-make-good.html>.

³² Queensland Office of Groundwater Impact Assessment (OGIA) (2017), SURAT Underground Water Impact Report. https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0007/1257838/surat-uwir-annual-report-2017.pdf.

4.2 Federal government regulation of water

4.2.1 Standing Council on Energy and Resources (SCER) — coal seam gas

The harmonisation approach to regulatory reform has been promoted through the National Harmonised Regulatory Framework for Natural Gas from Coal Seams (SCER Framework) and the Multiple Land Use Framework (MLUF) prepared by the Standing Council on Energy and Resources (SCER).³³

SCER (2013) contends that ‘a nationally consistent application of leading practices for the regulation of industry activities is currently not in place’ and that consequently ‘governments should work towards streamlined, transparent and consistent legislated approvals processes where duplication is minimised.’ The outcome of this process should be a ‘strong, consistent and harmonised leading practice regulatory regime that will assist in the sustainable development of the industry’ and ‘ultimately ... build community confidence in the operation of the industry’ (SCER, 2013).

The SCER Framework sets out 18 guiding principles and overarching strategies pertaining to key issues such as well integrity (principles 3, 4, 5 and 6), hydraulic fracturing and chemical use (principles 5, and 12–18) and water management.

4.2.2 National water Initiative and oil and gas

State and territory governments have been undertaking a process of continuous reform of water policy, commencing with a national approach in 1994 under COAG’s Water Reform Framework. Subsequent commitments were made under the National Water Initiative in 2004.³⁴ The main objectives of a national strategic approach was to establish an efficient and sustainable water industry to achieve efficient and sustainable urban and rural water use.

On 25 June 2004 the Council of Australian Governments (CoAG) signed the Intergovernmental Agreement on a National Water Initiative (NWI). The Australian oil and gas industry supports the principles in the NWI and agrees that clear and transparent market and water access can increase investment certainty and increase efficiency in water use.

The NWI recognises (clause 34) that the oil and gas industry may face ‘special circumstances’ and those issues facing the sector will have to be addressed by policies and measures beyond the scope of the agreement.³⁵ This recognition reflects the remote nature of many of the industry’s operations where there is little or no competition for water resources, the relatively temporary operational nature (relative to other users such as agriculture) and its use of non-potable/hyper saline water.

The oil and gas industry supports the 2004 Intergovernmental Agreement on a National Water Initiative (NWI) and state regulatory processes for accessing water. Further clarity on Clause 34 should be included in the NWI.

Water resource planning should include a broad range of economic sectors, including the petroleum industry and greater emphasis needs to be given to the extractive industries to ensure high-value use and to incentivise the use of ‘fit for purpose’ waters.

³³ Council of Australian Government (2013) *National Harmonised Framework for Coal Seam Gas*, <http://www.coagenergycouncil.gov.au/publications/national-harmonised-regulatory-framework-natural-gas-coal-seams>.

³⁴ <http://www.agriculture.gov.au/water/policy/coag>.

³⁵ Council of Australia Government (2004), Intergovernmental Agreement on a National Water Initiative, clause 34, pp6–7, June.

4.2.3 2011 National Partnership Agreement and the Independent Expert Scientific Committee

The National Partnership Agreement on Coal Seam Gas and Large Coal Mining Development (the NPA) was entered into in 2012 between the Australian Government and state governments of Queensland, New South Wales, Victoria and South Australia.

The overarching objective of the NPA was to strengthen the regulation of coal seam gas and large coal mining development by ensuring that future decisions are informed by substantially improved science and independent expert advice. To achieve this objective, the NPA provided for the following outcomes:

- increased evidence supports strategic and regional scale management of coal seam gas and large coal mining developments and their impact on water resources
- strengthened scientific evidence and independent expertise informs regulatory decisions on coal seam gas and large coal mining developments that are likely to have a significant impact on water resources
- well informed communities have greater confidence in Commonwealth and state regulation of coal seam gas and large coal mining development.

On 9 November 2012, the Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development (Committee) was established following the coming into force of amendments to the *Environment Protection and Biodiversity Conservation 1999* (Cth) (EPBC Act). These reforms require decision makers to obtain and take into account the Committee's advice on the impacts of coal seam gas (CSG) and large coal mining (LCM) developments that are likely to have a significant impact on water resources before deciding whether or not to approve the development.

The Commonwealth, with advice from the Independent Expert Scientific Committee and input from relevant jurisdictions, should continue to develop and implement its research program on the water-related impacts of coal seam gas development. This research will help ensure that decisions involving projects that may have a significant impact on water resources are based on the best available science.

4.2.4 Water and the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act)

The *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) is the Australian Government's key environmental legislation. The EPBC Act focuses Australian Government interests on the protection of matters of national environmental significance (NES), with the states and territories having responsibility for matters of state and local significance.

The nine matters of national environmental significance (MNES) are:

- | | |
|---|--|
| 1 world heritage properties | 5 migratory species |
| 2 national heritage places | 6 Commonwealth marine areas |
| 3 wetlands of international importance (often called 'Ramsar' wetlands after the international treaty under which such wetlands are listed) | 7 the Great Barrier Reef Marine Park |
| 4 nationally threatened species and ecological communities | 8 nuclear actions (including uranium mining) |
| | 9 a water resource, in relation to coal seam gas development and large coal mining development (since 22 June 2013). |

Oil and gas projects are assessed under the EPBC Act when a proposed project has the potential to have a significant impact on a matter of national environmental significance.

5

Associated water from coal seams

- Associated water is water that is pumped from the coal seams in order to extract gas.
- Water production by the Queensland natural gas industry accounts for a small fraction of national water use.
- In Queensland, associated water is regulated under numerous acts of legislation, including the *Petroleum and Gas (Production and Safety) Act 2004*; *Petroleum Act 1923*; *Environmental Protection Act 1994*; and the *Water Act 2000*.
- The Underground Water Impact Report (UWIR) by the Office of Groundwater Impact Assessment indicates that water production by the CSG industry will have a localised impact on existing private water bores in Queensland.
- If a petroleum activity in QLD impacts on the capacity of a landholder's bore the relevant company is required to make good the impact.
- CSG water quality varies across regions, but typically has a quality which restricts its highest beneficial use to stock watering.
- >90 per cent of associated water produced in Queensland is treated and made available for beneficial use with most being used in the agricultural industry.
- Landholders receiving treated water use the water to increase irrigated cropping and livestock watering—boosting agricultural production, economic flow-on opportunities and community benefits.
- The Darling Downs region in Queensland accounts for a significant proportion of the petroleum industry's onshore water take and because of the industry the region is now one of the most extensively studied and monitored aquifer systems in the world. All work to date indicates there will be minimal impacts on existing water users as a result of the industry's water take.

In Australia, coal seam gas resources are primarily located in Queensland and New South Wales.

All coals contain natural gas to some extent. In the early days of coal mining, removing gas from mines was a major challenge if mining was to proceed safely. In modern times, the gas in coal became seen as a valuable energy resource.

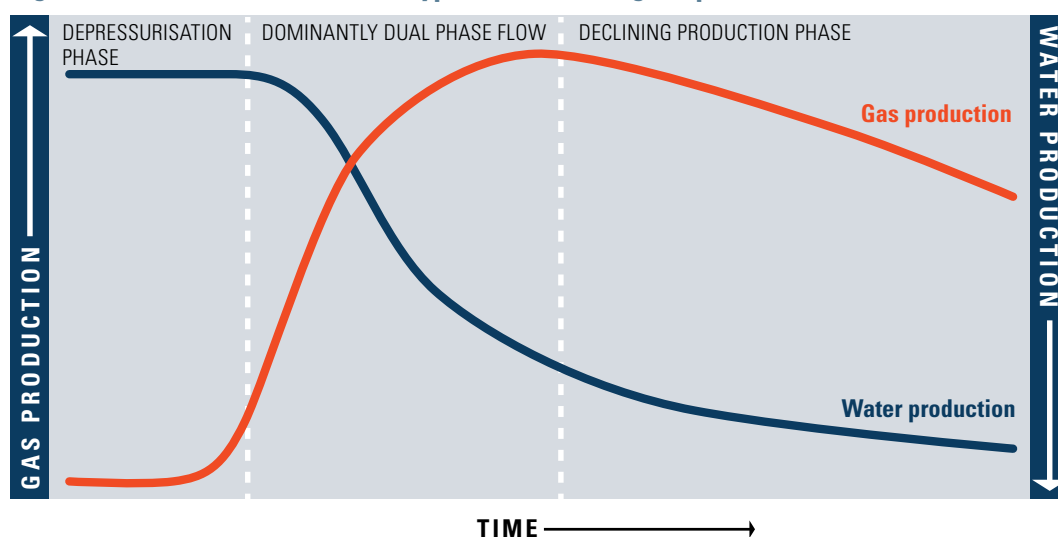
5.2.1 CSG water

CSG is adsorbed into the coal matrix and is held in place by the pressure of formation water. To extract the gas, a well is drilled into the coal seam and formation water from the coal cleats and fractures is pumped and withdrawn. The removal of water in the coal seam reduces the pressure, enabling the CSG to be released (desorbed) from the coal micropores and cleats, and allowing the gas and 'produced water' to be carried to the surface.

No two wells or coal seams behave identically and associated water production can vary from a few thousand to hundreds of thousands of litres a day, depending on the underground water pressures and geology. A well will deliver most of its water at the start of the pumping phase. As the water is pumped from the coal formation, the pressure is released from the seam, and the gas begins to flow.

Associated water production and gas production are inversely proportional. As water rates decline, gas production increases (See Figure 5).

Figure 5: Gas and water flow for a typical coal seam gas operation



The water pumping phase is unique to producing gas from coal seams. But the drilling techniques, surface equipment and gas compositions are not materially different from conventional gas production, which has been going on for decades in Australia. Not all coals are suitable for production. Commercial viability depends on the permeability of the coal, and its ability to flow gas, as well as the costs of drilling and proximity to infrastructure and customers.

Coal is naturally fractured. Cracks in the structure of the coal are referred to as 'cleats'. Water and natural gas are trapped in these cleats. Coals with more cleats are more permeable, which enhances the rate at which the water and gas can move through the coal's structure.

Coals with lower permeability do not require as much water to be pumped to reduce the pressure on the coal. This is why some operations—for example in NSW and Queensland's Bowen Basin—produce lower volumes of water. Areas with higher permeability generally produce higher volumes of water. Different CSG operations produce differing amounts of water.

5.2.2 Quality of associated water

Water trapped in situ contains salts and minerals that were part of the inland seas in which they were formed. Water that has entered the coal seam via aquifer recharge will collect salts and minerals as it travels through the surrounding geological formations. These salts and minerals are then captured in the water within coal seams in the same way that they are found in surrounding aquifers.³⁶

Associated water quality varies across regions, but is typically high in total dissolved solids, bicarbonate, hardness, and silica. The water contains mainly sodium chloride varying from 200 to more than 10,000 milligrams per litre (mg/L), sodium bicarbonate and traces of other compounds. Co-produced water is generally brackish, with salinity levels ranging from about 300 to 10,000 mg/L. By comparison, the salinity of water supplies for Australian towns can range from less than 250 up to about 1000 mg/L, and seawater is about 35,000 mg/L³⁷

Consequently companies have invested in water treatment to improve the quality of the water for beneficial use in line with the QLD Government's water policy (23).³⁸ The most common treatment system is reverse osmosis (RO) desalination with suitable pre-treatment steps have been employed to remove elevated salts and other compounds before CSG water can be used beneficially. One common form of beneficial reuse of the treated water is the irrigation of agricultural crops and forestry.

5.2.3 Associated water volumes

The volume of produced water extracted from each well can vary considerably between wells and regions depending on geological conditions. During the planning phase for gas field development, estimates of co-produced water volumes are necessary to formulate appropriate management arrangements. As the gas field is further developed, more representative data is available on well yield, enabling volumetric predictions to be refined over time.

The total volume of co-produced water in Queensland (Surat CMA) is estimated to be approximately 55 Gigalitres per year and, rather than been used by the gas industry, almost all of this water is treated to meet strict water quality standards and beneficially used for agriculture, industry, and managed aquifer recharge. The rate of associated water extraction is less than initially expected due to the nature of the coal being encountered. The Great Artesian Basin (GAB) contains 65 million gigalitres of water.^{39,40}

There are around 6500 licences and 21 water permits in Queensland. Cumulatively, Queensland water users take about 315 gigalitres per year from the Great Artesian Basin.

36 CSIRO (2014) Great Artesian Basin and Coal Seam Gas. Factsheet 14-00589. Canberra.

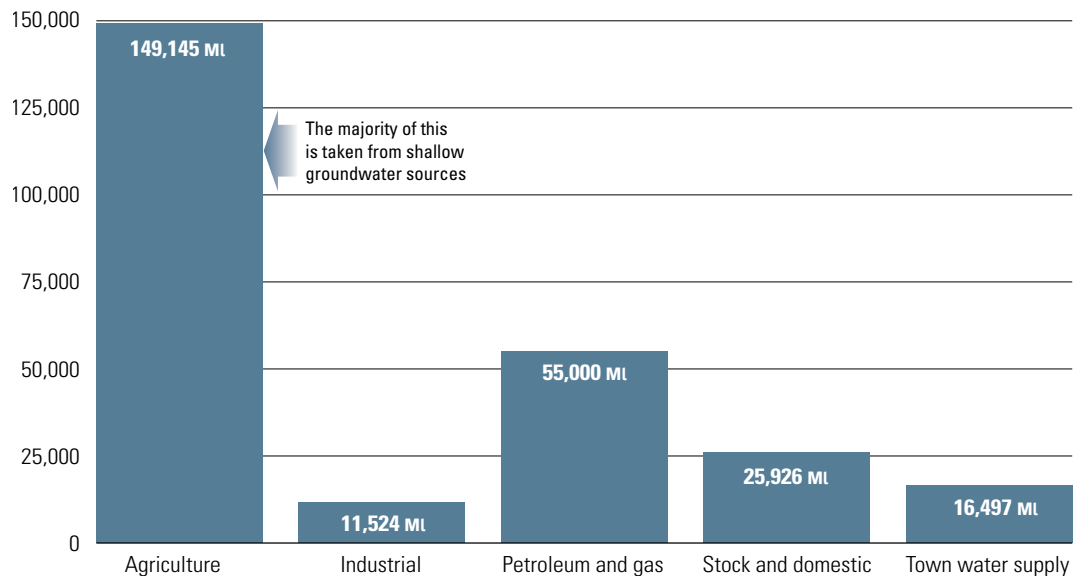
37 Australian Government (2017), Independent Expert Scientific Committee.
<http://www.iesc.environment.gov.au/publications/csg-extraction-and-co-produced-water#fn4>.

38 Coal Seam Gas Water Management Policy 2012
<https://www.ehp.qld.gov.au/assets/documents/regulation/rs-po-csg-water-management-policy.pdf>.

39 Great Artesian Basin Coordinating Committee (2014) *Great Artesian Basin Strategic Management Plan—Progress & Achievements to 2008* http://www.gabcc.org.au/images/DL_684_.pdf.

40 CSIRO, 2008. *Background report on the Great Artesian Basin. A report to the Australian Government from the CSIRO Murray–Darling Basin Sustainable Yields Project*. Contributing author Herczeg, AL.
<http://www.clw.csiro.au/publications/waterforahealthycountry/mdbsy/technical/S-GreatArtesianBasin.pdf>.

Figure 6: Estimated annual groundwater take in the Surat CMA (Ml)



SOURCE: OGIA 2016 & 2017

5.2.4 Non-associated water use

Non-Associated Water is the water that is required for authorised petroleum activities but intentionally abstracted from a target aquifer with the express purpose of being used within the project.

The demand for water by the petroleum industry is often misunderstood and overestimated. Demand for non-associated water is short duration, with the highest demand being during construction activities prior to production. Long term demand is in small volumes.

5.2.5 Aquifers and gas wells

When water is produced from a well, there is a decline in the water pressure in the deeper formations around the individual well. Under the Queensland regulatory framework, an area of concentrated development, where impacts on water pressure in aquifers are likely to be overlapping from multiple petroleum operations, can be declared a cumulative management area (CMA).

In 2012, the Queensland Government commissioned the preparation of the *Surat Underground Water Impact Report*⁴¹ which covers the vast majority of producing coal seam gas operations in Queensland. This report was updated in 2016.

In the CMA, the Office of Groundwater Impact Assessment (OGIA) is responsible for:

- predicting the regional impacts on water pressures in aquifers
- developing water monitoring and spring management strategies
- assigning responsibility to individual petroleum tenure holders for implementing specific parts of these strategies.

41 <https://www.dnrm.qld.gov.au/ogia/surat-underground-water-impact-report>

The report collated information on regional aquifers, existing water bores and petroleum wells, as well as the number and location of further wells to be drilled as part of the gas industry's development. It used this information to forecast the expected level of impacts. The report also identified 'immediately affected areas' and 'long-term affected areas'.

The immediately affected area is defined as the area where water level impacts will exceed a nominated threshold level within a three-year period. Long-term affected areas are those that will be affected at any time in the future.

The threshold levels have been set at greater than five-metre decline in water level, in consolidated aquifers (i.e. sandstone aquifers) and three-metre decline in unconsolidated aquifers (i.e. sand aquifers).

This information was collated into one mega-model⁵ to predict areas that may experience future groundwater impacts. The cumulative model covers an area the size of Germany and is referred to as the Surat Cumulative Management Area.

Gas companies have installed close to 1500 monitoring points to detect any changes in aquifer pressure (using vibrating wireline piezometers) or changes in the chemistry in the aquifers underlying their permit areas. This information is delivered to the Queensland Office of Groundwater Impact Assessment (OGIA⁴²) on a six-monthly basis. Tenement holders are required to 'make-good' on any bore level decline by providing alternative water supplies to the landholders. This may include drilling new, deeper bores, or supplying treated water to the affected properties.

5.2.6 Beneficial use of associated water

Where properly managed and treated, associated water can be reused in a range of different ways including irrigation. Regulatory requirements in Queensland ensure where possible associated water is used for a purpose that is beneficial to one or more of the following: the environment, existing or new water users, and existing or new water-dependent industries.⁴³ Beneficial reuse can include:

- industrial reuse—e.g. cooling water which would otherwise have been taken from local streams or groundwater
- agricultural reuse—reducing the need to extract water from local aquifers
- injection—increasing the volume of water stored in local aquifers
- river discharge—blending with seasonal non-permanent streams.

In order to fulfil the requirements of the CSG Water Management Policy, companies are required to investigate options for beneficial reuse of the water and to treat the water so that it is fit for purpose. While the level of salt in water varies depending on the source, water treatment processes typically involve desalination, and the most commonly used desalination technique is reverse osmosis.

42 <https://www.dnrm.qld.gov.au/ogia/role>.

43 <https://www.ehp.qld.gov.au/management/non-mining/csg-water.html>.

The industry has invested over \$3 billion in water treatment and recycling infrastructure to meet these requirements. In the last financial year 41.8 gigalitres of water was provided for beneficial use with the vast majority (83 per cent) treated to a high quality and used in irrigation⁴⁴. Associated water is also used to recharge depleted aquifers through managed reinjection.

Two main processes are used to treat water drawn from coal seams:

1 Desalination

Capital cities around Australia have adopted desalination to produce drinking water from the ocean. The industry is using the same proven technology to purify water it withdraws from coal seams.

2 Amendment

Water with a low salt content can be treated by using an amendment process. This involves changing the mineral make-up of the water to produce water that is suitable for the intended purpose. The suitability of amended water for any other uses is determined by the water quality and is regulated by the state government.

After desalination a brine (salty water) is produced. Industry works within strict government guidelines to ensure brine is always managed safely and responsibly. At Roma, the brine left over after desalination is reinjected into deep underground aquifers which are already high in salt. In any new areas of operation in future, this will be dependent on the geology of the areas.

⁴⁴ Water reuse from APPEA industry survey 2016–17.

CASE STUDY: CSG water used to grow crops

The Fairymeadow Road Irrigation Pipeline (FRIP) project was delivered by Origin on behalf of Australia Pacific LNG. The project involved construction of the 1870 megalitre irrigation storage dam located on the Monreagh property, the Monreagh pump station, the pipeline along Fairymeadow Road, and offtake points for participating landholders.⁴⁵

The FRIP project provides the opportunity for landholders to supplement their cropping programs with new irrigation.

This irrigation scheme is an example of the gas industry working with local farmers for mutual benefit. It allows the Fairymeadow area to be farmed more intensively, which leads to increased local jobs in agriculture, and a financial boost for the local agricultural contractors and associated agricultural businesses. This supply of water is especially important in times of drought.

Water began flowing to participating landholders in April 2014, filling on-farm dams and allowing farmers to prepare fields for planting winter crops which have since been harvested.

During 2016, the program delivered 11,208 megalitres of treated water to participating landholders. Treated water is delivered via pipeline from reverse osmosis water treatment facilities at Talinga and Condabri and stored in Monreagh Dam and transferred to landholders via the Fairymeadow Road Irrigation Pipeline.

The FRIP project forms part of Australia Pacific LNG's broader water management strategy, which uses a variety of solutions to find the best outcome for water resources according to local conditions.

The FRIP project is a practical application of the Queensland Government's Coal Seam Gas Water Management Policy (2012) which requires gas companies to find beneficial uses for treated water, and demonstrates how the agricultural and resources industries can work together to develop shared benefits.

Image 4: Treated water being used for irrigation



About the Fairymeadow Road Irrigation Pipeline Project:

- Seven participating landholders
- Covering an estimated 3500 hectares
- 15 gigalitres of treated water per year during peak production
- A 22 km water distribution pipeline along Fairymeadow Road
- A 1870 megalitre irrigation dam, located on the Monreagh property (Monreagh Dam) which provides buffer storage
- A pump station at Monreagh Dam
- Irrigation off-takes for each participating landholder property along the water pipeline
- Water delivery gates to measure flow at each participating landholder property
- Talinga Water Treatment Facility
- Condabri Water Treatment Facility and booster pump station.

⁴⁵ Origin Energy — Fairymeadow Road. Water to Landholders (2017) <https://www.originenergy.com.au/content/dam/origin/about/our-approach/docs/OurApproach-2016-Fairymeadow-Road.pdf>.

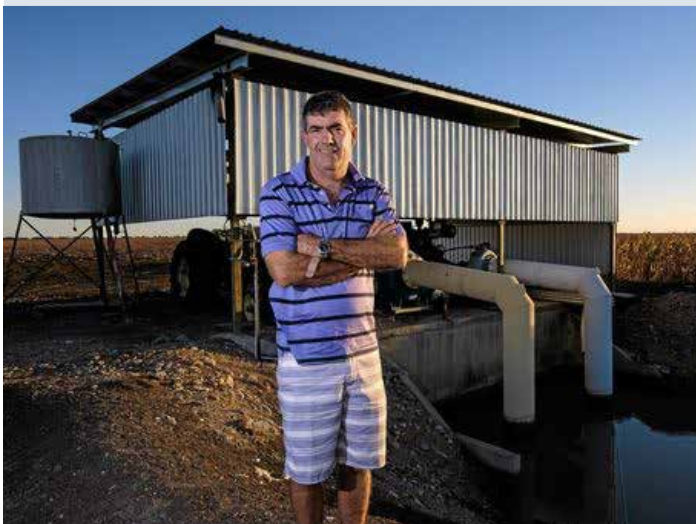
CASE STUDY: Chinchilla News



The ebbs and flows of CSG water use. The Chinchilla News. 27th May 2016⁴⁶

It was the first evening of a cutting horse event at the Chinchilla Showgrounds several months ago when two men sitting in the stands were talking farming. The man on the right leant in to the man on the left after a lengthy conversation and said: 'But I'll tell you what, those blokes who are on coal seam gas (CSG) water, I'd like to know how they're doing.' 'Yep,' the man continued. 'That CSG water must be like having a licence to print money.'

Image 5: Greg Bender on his property 'Burradoo' in Hopeland. Matthew Newton



Greg Bender, who farms a 2000 acre patch of earth called Burradoo, just south of the Chinchilla Weir, laughs and shakes his head when it's put to him like that. 'I wouldn't say it's a licence to print money,' he said, chuckling. 'It's a licence to turn it over. It's definitely been financially rewarding for us since it's come on stream, but it's been a lot of work and a lot of risk too.'

To say the availability of treated CSG water through Queensland Gas Company's (QGC) beneficial re-use scheme has transformed Mr Bender's farming practices would be an understatement.

Originally a dry-land cropping set-up where he might have planted one crop every 18 months, Mr Bender now has 1800 acres of irrigation at his disposal.

⁴⁶ Chinchilla News (2016) The ebbs and flow of CSG water use <https://www.chinchillanews.com.au/news/the-ebbs-and-flows-of-csg-water-use/3034389/>

CASE STUDY: Chinchilla News

'It's been three pretty solid years of building ditches, levelling paddocks and installing pipelines and pumps,' Mr Bender said. 'It was alright for the first 12 months because you didn't have the country—but then after the initial 12 months all of a sudden you've got another 1000 acres of irrigation and you're growing all these crops, so you've created all this extra workload just to grow the crops and then you're still trying to do the development work as well.'

Mr Bender put in for and signed a contract with QGC for up to 4800 ML/year across two properties, though it is unlikely he will ever actually receive those volumes of water. Teething problems at QGC's Kenya Water Treatment Plant meant the water allocations were inconsistent at first.

'It was just up and down; one month you'd get 100% and then all of a sudden the allocation might get halved for the month at a day's notice,' Mr Bender said. Since then the allocations have become more consistent, though it is unlikely the scheme will ever reach its full potential.

Mr Bender estimates he has pumped about 6000 megalitres in 32 months, or about 2400 megalitres per year. With the madness of the early years behind him, Mr Bender is now seeing the fruits of his labour.

Where once Burradoo's main crop was cotton, with single paddocks harvested once every two-three years, now he's got a continual cash flow. 'Nearly every month we're selling something because we're growing crops all year round,' he said.

The almost guaranteed supply of water has given Mr Bender the confidence to hedge his bets and take advantage of good commodity prices long before it's time to harvest. 'There's a lot of marketing opportunities... we forward sold a crop of cotton six months ago because we knew we had the water to grow it and the price was good,' he said. 'Where's when you haven't got the water it's always in the back of your mind that I'm not game to forward sell it just in case.'

'The classic at the moment is these chickpeas—you've heard them all talking about how chickpeas are going to be an all-time high this year? Well we haven't grown chickpeas in probably 10 years and we're probably going to grow half the farm under them now, because we can.'

There are other benefits too—Mr Bender has had to put on three full-time employees to keep up with the increase in work and with all the pumping going on, machines need maintaining more often. Another positive he didn't factor into his plans is that with so much country under irrigation, any time there's a rainfall event—even a small one—the run-off goes straight into his dam.

'It's been a huge benefit to us,' he said. 'We were probably a bit lucky because we were already existing irrigators and we had a lot of machinery and had built a channel down to the river based on the fact that we might be able to pump water with a flood harvesting licence.'

Mr Bender said he looked at the figures and took a gamble, which it now seems will pay off. 'If it was as good as what they said it was, it would have been absolutely brilliant, but I mean, some water is better than none. That's all I looked at. I probably was a bit fortunate that I went holus bolus and worked out that'd be the maximum amount of water I could use per year and put in for it.'

Treated CSG water is piped from the Kenya Water Treatment Plant along a 20 km pipeline into the Chinchilla Weir. To date Sunwater has delivered a total of 45,186 megalitres since operations began in 2012–13.



So far this year, the pipeline has carried an average of 52 megalitres per day. The pipes are capable of supplying up to 100 megalitres per day. Some of that water is taken direct from the pipeline, as in the case of farms like Nine Mile Lucerne, on the Chinchilla-Tara Road.

The remainder enters into the weir. The CSG water accumulates in the weir over the course of the month, before it is let out in flows for other users downstream of the weir to take their allocations. While downstream releases of irrigation water cease when the weir water level drops below a certain point, treated CSG water must be released, regardless.

CASE STUDY: Chinchilla News

The Chinchilla Weir last week was sitting at 31% capacity. Treated CSG water is released from the weir regardless of water storage levels.

A Sunwater spokesperson explained this was because the purpose of releases from the Beneficial Use Scheme is to provide regular scheduled water supply for agricultural production including irrigation and stock water.

Farmers on the CSG water scheme run the risk of being fined \$160 per megalitre if they do not use all of their allocation each month.

Downstream of the weir on the banks of the Condamine sits 'Lallalindi', Don and Lorraine Bell's 840 hectare cattle property.

While other farmers on the scheme already had irrigation infrastructure in place, the Bells had to start from scratch.

In 2012, Mr Bell bought and installed a pivot in preparation for the supply of CSG water.

'The pivot's been in for about four years, but we went two years before we started getting water. The pivot just sat there. It was a most expensive bird roost,' he said.

'That was one of the big issues from my point of view. We had to have our system ready to go when they started reverse osmosis on the water, and it was supposed to happen in 2011 or 2012, and it didn't.

'So everybody had to have their systems all ready. So here it was sitting there ready to roll and we didn't get any water for two years because (QGC) took longer to build their RO plant than what they thought it would.'

These days, Mr Bell, like the rest of the farmers on the scheme, is receiving about half the allocation he thought he would. That's okay in the winter when he doesn't use as much water, but the hotter summer months are a squeeze.

The pivot waters about 35 hectares, half of which is under improved pasture with Rhodes Grass and the other half under forage sorghum and burgundy bean.

'It gives us a lot more flexibility in what we do because we've got that feed that can be produced nearly all the time — the problems are that sometimes in summer time we don't get enough water for what we want to do,' he said.

'It would be better if we had more water... at the moment I'm only watering half of my area because our water is down, and then if they cut us back even more it's going to make it more difficult.'

Because the Bells are only receiving half their total allocation, lack of water storage facilities becomes an issue — something which would be useful in the winter time.

But water storage costs money.

'We didn't want to go back into too much debt at our age,' Mrs Bell said.

'None of our boys are probably going to come back onto the farm so we didn't want to set ourselves up with a big debt. It was a bit of a trial, really, to go ahead and do what we've done.'

Mr Bell said that because they weren't irrigators before signing onto the scheme, they didn't have a storage, nor did they think they could afford to install one.

'150 ML storage will cost \$150–200,000 probably and we already had used enough money to set (the pivot) up down there,' he said.

'We're actually looking into it at the moment. We've got some people giving us some technical advice on how we can go about building a storage and making our system a little more efficient.'

Despite the ongoing issues with supply, Mr Bell said the pivot had given him more flexibility. In the past, there have been plenty of times where the Bells have had to sell their cows due to drought. He now runs 250 head of cattle, but in the past has had to cut his herd back during the dry.

During a period of severe drought in 2006, he had 32 cattle on the property.

'It was so dry the truck got bogged in the sand,' he recalled.

Mr Bell hopes that with the CSG water allocation, that won't happen again.

'It doesn't drought-proof you, but you can deal with the dry times a bit easier,' he said.

6 Brine and salt management

6.1 Background

As noted above, many communities and much agricultural production in regional Queensland is sustained by groundwater produced from the Great Artesian Basin (GAB). Where aquifers are shallow enough to access water economically landholders and other water users have drilled into them to access groundwater.

In Queensland's Surat Basin the Bungil, Mooga, and Gubberamunda are the most commonly used aquifers. The Walloons Coal Measures in the Surat has also been a longstanding source of groundwater for landholders. However, the moderate levels of salt in Walloons groundwater has limited its uses as without significant treatment the water is typically unsuitable for irrigation or human consumption, and therefore it has mostly been used for stock watering.

For many decades it has been common knowledge that natural gas is also present in the Walloons with landholder water bores sometimes becoming 'gassy' as water was produced. But it is only in recent years that innovation and the application of leading edge technology have harnessed this resource transforming the Walloons into a globally significant source of natural gas.

Producing gas from the Walloons and other coal seams requires the formation pressure to first be lowered by extracting some of the water and a policy framework has been put in place by the Queensland Government for the management of this water. This framework specifies that water must be beneficially used where possible, and to meet the water quality standards for beneficial use Walloons groundwater must be treated and desalinated.

The Queensland gas industry is also a major supplier of clean, desalinated water to communities and farmers. The industry has constructed 17 water treatment plants that transform low quality Walloons water into desalinated water suitable for a range of beneficial uses including:

- irrigation
- aquifer injection
- livestock watering
- human consumption
- construction activities.

The approach of maximising desalinated water available for beneficial use, which has clear benefits and is supported by all stakeholders, also increases brine volumes as the water treatment process generates a brine waste stream that contains the salt removed from groundwater.

Notwithstanding the need to manage brine and salt the desalinated water produced by the industry is in very high demand by landholders and communities. Over 40 gegalitres of water was provided by industry for beneficial use in 2016–17 and 83 per cent of this volume was used for irrigation.

The brine by-product of the treatment process is currently stored in dedicated ponds that are designed, constructed and operated in accordance with strict standards with 14.7 gegalitres of brine storage capacity in place.

Estimates of the total amount of salt in brine produced by the industry have declined significantly since original estimates were made in 2008. Total forecast salt volume was 15.4 million tonnes in 2008 and now stand at 6.1 million tonnes. The brine storage in place is therefore enough to hold brine produced until at least 2025, and several years more in most areas. The industry will continue to assess new long-term management options if they become available and will implement the most feasible options based on the outcomes of studies and feasibility assessments.

The list of feasibility studies undertaken by industry to date is provided in Table 2 of this report. These investigations include collaboration across the industry which has been ongoing since 2010 and has focussed on four main options:

- 1 Selective salt recovery—beneficial use option.
- 2 Injection—disposal option.
- 3 Ocean outfall—disposal option.
- 4 Encapsulation—disposal option.

The feasibility of each option as a whole of industry management solution has been assessed in accordance with feasibility criteria specified within government policies to determine a preferred option.

The results of this work to date are:

- 1 Selective salt recovery, while a beneficial use and preferable under the policy, is not feasible on the basis of:
 - a environmental impacts including increased greenhouse gas emissions and land disturbance area
 - b the likelihood of significant negative impacts to existing commercial salt suppliers
 - c significant transport and safety risks
 - d significant uncertainty that the technology can be successfully deployed, and
 - e prohibitive cost.
- 2 Brine injection is not feasible as there are no identified geological formations that meet the technical criteria for injection.
- 3 Ocean outfall is technically feasible, and disposing of salt into the ocean would have minimal environmental impacts, but there are significant obstacles to implementation including:
 - a primarily, the potential for anti-development activist groups to seek to generate community opposition to putting salt in the ocean
 - b logistical complications due to the geographical spread of operations
 - c cost of installation.
- 4 Encapsulation in purpose-built facilities is the optimal option in the absence of regulatory change or a shift in community sentiment. Encapsulation facilities constructed off prime agricultural land, and either adjacent to brine ponds or within brine ponds that are no longer required for brine storage, or at a third-party regulated waste facility are the most viable/least impact whole-of-industry management solution.

6.2 Regulatory requirements

The Queensland Government’s CSG Water Management Policy recognises that the treatment of ground water using desalination technologies results in brine and, ultimately, salt residues that must be appropriately managed. The policy is the only Queensland Government policy which sets priorities for brine and salt management and a framework to determine the feasibility of each option.

The policy sets out two priorities for brine and salt management—reuse then disposal. Operators must demonstrate that beneficial reuse has been fully considered and determined not to be feasible prior to considering disposal options (see Table 2).

Table 2: CSG Water Management Policy brine and salt management options, management principles and management criteria

Management options	Management principles	Management criteria
Treatment to create useable and saleable products	<p>Brine or salt residues can be treated to create saleable products, for example soda ash, and commercial salt.</p> <p>Using brine or salt residues to create saleable products may be authorised through the conditions of the environmental authority or through a beneficial use approval if it is to be undertaken outside the area of the petroleum tenure.</p>	<p>In determining the feasibility of treating brine or salt residues to create useable/saleable products operators must:</p> <ul style="list-style-type: none"> • identify potential uses of salt • undertake a feasibility assessment of potential uses of salt. This assessment should account for: <ul style="list-style-type: none"> • the period of time and volume of salt that would be available for use • the cost of treating salt to ensure it is at an appropriate standard for use.
Disposal of brine and salt	<p>The disposal of brine and salt must only be considered after a feasibility assessment has determined that there are no reasonable options to minimise the volume of waste for disposal.</p> <p>There are a range of options for the disposal of salt including:</p> <ul style="list-style-type: none"> • injecting brine underground • ocean outfall • disposing to a regulated waste facility. 	<p>After doing everything feasible to minimise the volume of waste for disposal, the operator must:</p> <ul style="list-style-type: none"> • convert the waste to a solid product wherever feasible • undertake a comprehensive risk assessment to ensure the salt does not contaminate or harm the environment, including consideration of potential natural disasters (e.g. flooding) • dispose of brine and salt away from sensitive receiving environments (this should be informed by local planning schemes and regional plans), including residential areas and good quality agricultural land.

6.3 Collaborative studies — long-term salt management

6.3.1 Identification of collaboration options

Each gas company is required by conditions established by the Queensland Government to undertake feasibility studies into the beneficial reuse of the salt waste as well as disposal options. In response to this requirement each company identified alternative options for brine and salt management informed by:

- commitments made in the project EIS
- conditions of the relevant EAs issued by the Queensland Government
- the CSG Water Management Policy (DEHP 2010)⁴⁷
- conditions imposed by the Queensland and Commonwealth governments on the approval of each project
- the waste management hierarchy outlined in the *Waste Reduction and Recycling Act 2011* (Qld).

The list of studies undertaken by the industry jointly and separately are provided in Table 3 alongside the key changes in the regulatory framework that have underpinned work to date. These studies provided the foundation and context for industry collaboration which commenced in 2010.

Industry collaboration was undertaken on four main options.

- 1 Selective salt recovery — beneficial use option.
- 2 Injection — disposal option.
- 3 Ocean outfall — disposal option.
- 4 Encapsulation — disposal option.

⁴⁷ The process of option identification occurred prior to the 2012 update of this policy.

Table 3: Industry water, brine and salt management studies

Year	Regulatory changes	Trials and investigations	Collaborative activities
2008–10	CSG Water Policy 2010	<ul style="list-style-type: none"> • Pongamia irrigation (APLNG) • Fairview Reverse Osmosis Plant and Irrigation of fodder crops (Santos) • Fairview Brine Injection (Santos) • AWAFA Associated Water Amendment Facility and Hardwood Plantation Irrigation (Santos) 	
2011	<i>Waste Reduction and Recycling Act 2011</i>	<ul style="list-style-type: none"> • Saltmaker brine concentration (APLNG) • Large scale brine storage (APLNG) • Watercourse discharge (APLNG) • Daandine WTF (Arrow) • Salt Recovery and Commercialisation Study (Santos) • Ocean outfall Assessment (Santos) • Depleted coal seam injection study (Santos) 	Selective salt recovery (QGC, APLNG, Arrow)
2012	CSG Water Management Policy 2012 New dam standards Using rivers to transport water prohibited	<ul style="list-style-type: none"> • Permeate injection (APLNG) • Acid regeneration trial (APLNG) • Salt recovery trial (APLNG) 	Ocean outfall (APLNG, Arrow)
2013	Federal EPBC 'water trigger' New waste levy	<ul style="list-style-type: none"> • Permeate injection to precipice sandstone (APLNG) • Ocean outfall (APLNG) • Irrigation of fodder crops using land amendment technology (Santos) • Roma and Fairview Reverse Osmosis Plants (Santos) • Brine concept assessment (Arrow) • Solar/wind evaporation trials (Santos) 	
2014	New beneficial use standards	<ul style="list-style-type: none"> • Brine injection (APLNG) • Brine concentration (APLNG) • Watercourse release (APLNG) • Fairy Meador Irrigation project (APLNG) • Roma Brine Injection trial (Santos) • Landfill salt study (Santos) • SEF concept study (QGC) • Crystalliser design (QGC) • Salt recovery options assessment (Arrow) • Roma fodder crop irrigation (Santos) 	QGC Saltcrete concept assessment
2015		<ul style="list-style-type: none"> • SEF FEED design (QGC) • SEF concept study (Arrow) • Salt plant concept study (Arrow) 	<p>Collaboration agreement (APLNG, QGC, Santos)</p> <p>Integrated water balance developed</p> <p>Brine transfers between proponents</p> <p>Western and eastern encapsulation options</p>

Year	Regulatory changes	Trials and investigations	Collaborative activities
2016	Chain of responsibility legislation Waste Reduction and Recycling Act amendments	<ul style="list-style-type: none"> • Brine and salt feasibility study (Arrow) • Blended water irrigation feasibility (APLNG) • FRIP increase (APLNG) • Watercourse discharge (Santos) • Localised irrigation trial (Santos) • Water quality and blending trials (Santos) 	
2017		<ul style="list-style-type: none"> • FRIP increase (APLNG) • Longstraws trial (APLNG) • Crystallisation field trial (QGC) • Bulk crystallisation laboratory trial (QGC) • Enhanced evaporation technology trial (QGC) 	Industry Salt Working Group
Future	New waste codes to be introduced Residual risk policy Changes to financial assurance		

6.3.2 Feasibility assessment of collaboration options

The industry has used the Queensland Government's CSG Water Management Policy 2012 to inform an assessment of the feasibility of each of the four options as a whole of industry brine and salt solution. The policy defines feasible as 'the benefits outweigh the costs—having considered a number of factors including environmental, economic and social issues'.

The feasibility of each of the options was assessed in accordance with this definition against the following key factors:

- The option must meet acceptable health safety and environment standards.
- The option must be technically feasible over the lifetime of the project.
- The option must not pose an unacceptable risk to the production of natural gas considering time, reliability and flexibility.
- The option must be socially acceptable.
- The option must be compliant with prevailing regulations and/or be approved by the administering authority within the timeframes required by each of the industry proponents.
- The option must be economically viable.

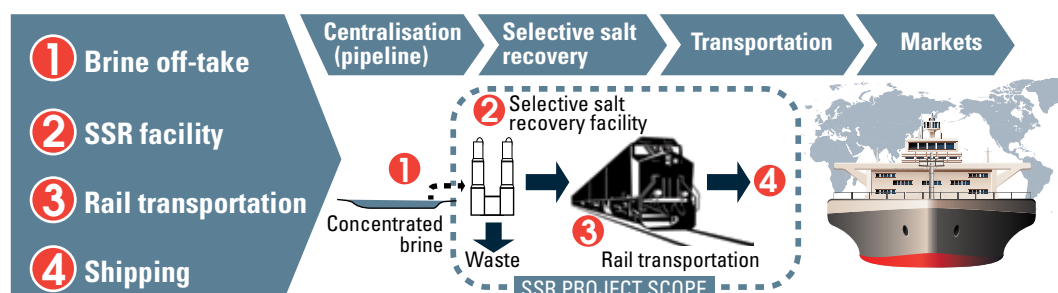
6.3.3 Feasibility of selective salt recovery (SSR)

6.3.3.1 Overview

Selective salt recovery (SSR) is a unique combination of existing technologies to produce salt products from brine for potential beneficial reuse, for example as inputs required by various industrial processes. Three industry proponents collaborated on a Pre-FEED and FEED investigation to inform a feasibility assessment of this option. The industry spent approximately \$60 million on the evaluation of this option.

The SSR process would commence after the stored brine has been sufficiently concentrated, either by brine concentrators, solar concentration, or a combination of both. Concentrated brine would be transported to the SSR facility through a purpose-built brine pipeline network and stored in a holding pond at the SSR facility. Salt crystallisers would then be used to fractionally crystallise brine into sodium chloride (table salt) and sodium carbonate (soda ash). The resulting salt products would then be available for transportation by rail prior to shipping to the international market. A schematic of the SSR process is contained in Figure 7: below.

Figure 7: Selective recovery process schematic



SSR Collaboration commenced around four pilot projects to test the feasibility of the SSR process. Of the four pilots conducted, two progressed. These two trials were further refined through a second piloting stage that demonstrated, at a pilot level, existing technology can be used to separate specific salts produced from CSG brine. The collaborative effort was led by QGC and the concept was developed further through the:

- identification of a preferred site for the SSR facility at Bellevue immediate south of the Miles Supply Base. This location was favoured because of its proximity to rail lines that could be used to transport salt products to market
- identification and assessment of markets to accept the salt products for sale. Evaluation of logistics for transporting salt from the Surat Basin to the Port of Brisbane for delivery to international markets, likely by rail from Miles
- conduction of a pre-Front End Engineering Design (pre-FEED) process with two independent consortia to develop the technical and commercial solution
- consideration of the brine pipeline network required to join QGC's concentrated brine ponds, APLNG's brine ponds and Arrows proposed brine ponds to the Bellevue site. It was determined that a 375km brine pipeline network would be required to transport brine from the QGC and APLNG brine ponds alone to a centralised SSR facility.

6.3.3.2 Feasibility assessment

Health and safety and environment assessment

A key feasibility criterion for the gas industry is that the option must be sustainable taking into account health, safety, security and environmental considerations.

With its ability to provide a complete beneficial reuse solution for brine, SSR provides an opportunity to limit the overall impact on the environment from one perspective. However, the feasibility assessment identified that there are a number of issues that weigh against SSR being a feasible solution from an environment and safety perspective. These include:

- SSR is a highly energy intensive process that uses more power and gas than any other alternatives considered and therefore results in significantly greater CO₂ emissions
- SSR relies upon use of a number of chemicals in its operation, thereby increasing safety risks for plant operations and transport of these chemicals to the SSR facility
- Supply of brine to a centralised facility through pipelines requires a pre-treatment process to be used, this pre-treatment generates additional solid and liquid waste streams that require disposal
- Mechanical vapour recompression used in the SSR results in significant noise that would require specific attenuation
- Transportation of salt products over long distances increases the risk of transport accidents, uncontrolled release and environmental impacts, and
- SSR does not provide the requisite certainty due to reliance on a single SSR facility and the proprietary nature of the technology used in the facility meaning that it could be difficult to locate a new operator if necessary.

Technical feasibility

SSR requires development of a bespoke solution using a combination of proven technology and processes to produce market ready salt products from brine. To assess the technical feasibility of SSR, the gas industry worked with two independent technology providers who developed pilot programs.

The key results from this study are as follows:

- The pilot programs and resulting data demonstrate that the proposed technical solution to achieve SSR is acceptable at a conceptual pilot level, but would be a world first and remains untested on a commercial scale. There are therefore inherent reliability and technology risks in proceeding with the SSR process.
- The SSR technology requires brine to be within a relatively narrow minimum and maximum specification. The narrow technical margin is impacted by many factors outside of the control of each proponent, including the composition of ground water. This makes it extremely difficult for all of the brine from one company to meet the specification, let alone the brine from the whole of industry. To manage this, the industry would be required to develop an alternate disposal solution for brine that is outside the required specifications.
- SSR is not able to easily accommodate variations in the volumes of brine which may result from the whole of the gas industry increasing the operational complexity.
- There is further uncertainty regarding the reliability of the SSR technology to achieve the required salt purity for sale where the brine does fall within the required composition range for SSR. The investigation found that technology providers would

not provide assurances that the end product would be suitable for market or be produced in volumes that would meet supply obligations. The end result is that without such assurances SSR does not ensure beneficial use of the salt produced and as such would require the gas industry to dispose of salt that fails to meet the required purity for sale.

The pilot programs demonstrated that whilst it is technically possible to use existing technology and processes in combinations that will produce market quality salts from brine, there are a number of issues that impact on the operability and reliability of the technology. These issues represent considerable risk to the overall CSG process.

Delivery timeframes

The delivery of an operational facility in a timely manner is a key evaluation criterion for a whole of industry solution to provide certainty as to the volume of brine storage required for each proponent and capacity available to ensure brine can be managed at the required rate. The whole-of-industry investigations determined that there is an extensive construction and procurement period for an SSR solution. There is also increased risk of schedule slippage as a result of developing a world first solution in a remote location. For this reason, the delivery timeframe is a key risk of pursuing the SSR solution.

Social acceptance

At a conceptual level, SSR is considered to be socially acceptable due to its ability to provide beneficial reuse of salts contained in brine. However, the SSR solution also requires an extensive brine pipeline network to connect the gas companies' brine ponds to a centralised SSR facility which is viewed negatively by the local community and landholders. As there is no direct beneficial impact to the local community and landholders from reuse of salt products, this strong community sentiment against brine pipelines weighs heavily against SSR as a solution likely to be accepted by the local community.

In addition, if SSR was adopted the industry would be entering the existing market for salt and competing with existing suppliers in a loss-making scenario who would therefore not be on an equal footing. Significant negative impacts on the market would therefore occur.

Compliance with government regulations

SSR was progressed as a potential whole-of-industry solution on the basis of it being a beneficial use option in accordance with the objectives of the water policy (DEHP 2012). However, market analysis demonstrated that the supply of salt from the gas industry would most likely be to international markets (as the Australian local market is limited in size and well established). Transportation costs alone would result in estimated \$60 per tonne net loss (excluding salt production costs). Therefore, the option is not considered a feasible beneficial use.

The SSR is considered to be consistent with the waste management hierarchy (EPP Waste 2012). However, the SSR option would still result in a waste stream requiring disposal (approximately 10–16 per cent of overall solids input) as a minimum, and would also require the utilization of significant resources (energy) to convert to a usable product.

Economics

To allow for an economic analysis of SSR facility to be undertaken two competitive bidders were engaged to provide indicative pricing for the facility. This comparison showed that the capital requirements ranged from \$620 million to \$700 million with operating costs of between \$51–\$55 million per annum which equates to an NPC of approximately \$800 million. Pipelines costs to connect the OGC and APLNG brine ponds to the SSR would require a further \$500 million increasing the NPC to between \$1,035–\$1,141 million.

The SSR technology cannot at this stage be implemented in a way which appropriately manages the risks of this new technology. Technology providers engaged in the process would not provide assurances that the SSR facility will create a product that is saleable in the market, or indeed that the technology can be successfully deployed. The issue of storing large volumes of residual salts would consequently re-emerge. Investment of ~\$800 million into this world first technology is therefore considered infeasible.

6.3.4 Feasibility of injection

6.3.4.3 Overview

The feasibility of a whole of industry brine solution based on injection is dependent on finding a geologically isolated formation which contains sufficient capacity for the forecast brine volume produced by the industry which either:

- does not contain groundwater
- or*
- where groundwater is present that the brine is of a similar or better quality than in-situ groundwater so as to minimise the potential for environmental harm to occur.

Each gas company conducted separate investigations with the objective of identifying a suitable injection target within their tenements with industry collaboration occurring based on information sharing of the outcomes of these investigations. The industry collectively spent in excess of \$50 million seeking to identify a suitable target. Only one company was able to find a potential target but this was subsequently found to have insufficient capacity for the brine volume generated from that one company alone.

Consideration was also given to the potential to dilute brine to increase the likelihood of finding a suitable target based on water quality but under the current policy framework this would negate the beneficial use of treated water and also increases the volume for injection. Further, injection of a diluted brine solution would need to occur at a significant depth which, along with the uncertainties in the occurrence of appropriate structures, introduces significant technical risks of accessing a highly pressurised system at depth.

6.3.4.4 Feasibility assessment

No suitable injection target has been identified by the gas industry therefore brine injection is assessed as being infeasible.

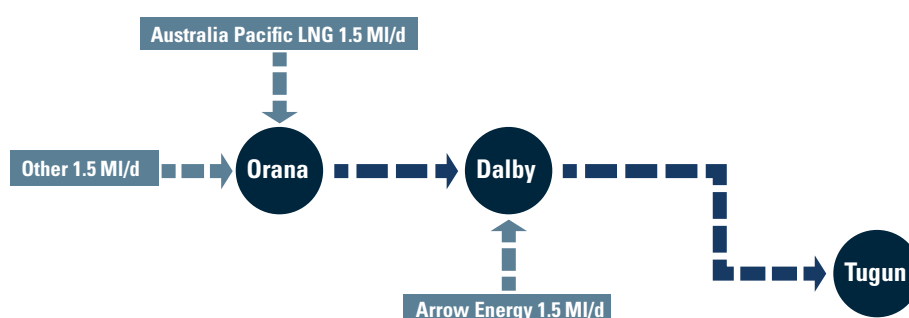
6.3.5 Feasibility of ocean outfall

6.3.5.5 Overview

The ocean outfall option requires the construction of a pipeline connecting each company's brine ponds to a coastal ocean outfall for discharge. Industry collaboration on this option commenced in 2012 with two industry proponents collaborating on the development of an ocean outfall option based on the construction of a 370km coastal transfer pipeline from Orana to the brine ocean outfall at the Tugun⁴⁸ desalination plant. An additional 350km of infield brine pipelines would be necessary to connect the brine ponds of those two proponents to the transfer pipeline.

The option concept is shown in Figure 8.

Figure 8: Ocean outfall schematic



Whilst the option allowed for the connection of all industry proponents to the coastal transfer pipeline hundreds of kilometres of additional pipelines would be required to connect all proponents brine ponds to the coastal transfer pipeline and ocean outfall.

6.3.5.6 Feasibility assessment

Health and safety and environment assessment

The potential pipeline route could traverse approximately 1800 properties with the 80 km eastern section of the pipeline traversing a highly developed urban area through the Gold Coast involving 'no-dig' crossings, working beside heavily trafficked roads and the risk of striking existing services. This activity is considered to present a medium to high risk to safety and wellbeing of employees and the community.

The construction activities would require significant land disturbance (1800 ha of which 190 ha is classified as SCL and 290 ha good quality agricultural land) and are therefore expected to pose a medium risk to air, ecology, ground and surface waters, land and soils.

Though the disposal of salt into the ocean is not uncommon, any kind of project undertaking this activity would need to ensure there was extensive analysis and monitoring over a significant period of time to ensure impacts are minimised.

Technical feasibility

The technical feasibility of an ocean outfall option is dependent on two main components:

- pipeline integrity
- performance of the ocean outfall.

⁴⁸ At present there are no plans to pursue this option. Tugun was selected to enable the concept to be evaluated given the existence of a desalination plant with brine outfall at this location.

Pipeline integrity

The pipeline infrastructure for the transport of brine must be specifically engineered to ensure containment and minimise corrosion over the lifetime of the gas industry. Suitable pipeline materials are available but significantly increase the costs of the pipeline compared with a potable water or water pipeline.

Performance of the ocean outfall

The ocean outfall will be required to operate over a wide range of salinity concentrations and composition and be capable of achieving the necessary diffusion of brine within a mixing zone which does not cause a negative impact.

Preliminary assessments undertaken by industry indicate that the Tugun ocean outfall, as an example concept, is capable of operating over a relatively broad range of salinity concentrations. This work was undertaken to enable the ocean outfall concept to be evaluated and does not represent any plans to pursue the option.

Delivery timeframes

The delivery of an operational facility in a timely manner is a key evaluation criterion for a whole of industry solution to provide certainty. The whole of industry investigations have determined that there is an extensive construction and procurement period for an ocean outfall solution. There is also increased risk of schedule slippage as a result of construction of connecting pipelines, trunklines in rural land plus construction of an 80km section of the pipeline through a highly urbanised area. For this reason, the delivery timeframe is a key risk of pursuing the ocean outfall solution.

Social acceptance

The ocean outfall option was assessed as representing a severe risk in terms of social acceptance due to:

- the pipeline traversing over 1800 different properties, with 50,000 properties are located within 800m of the pipeline
- potential for anti-development activist groups to seek to generate community opposition to putting salt into the ocean, and
- dis-amenity during pipeline construction and traffic and transport disruption due to approximately 80km of the pipeline running through a developed urban area.

Compliance with government regulations

The ocean outfall option is a disposal option and so is therefore a least preferred solution in the water policy (DEHP 2012), however it is considered that it would comply with the policy if beneficial use options are infeasible.

Economics

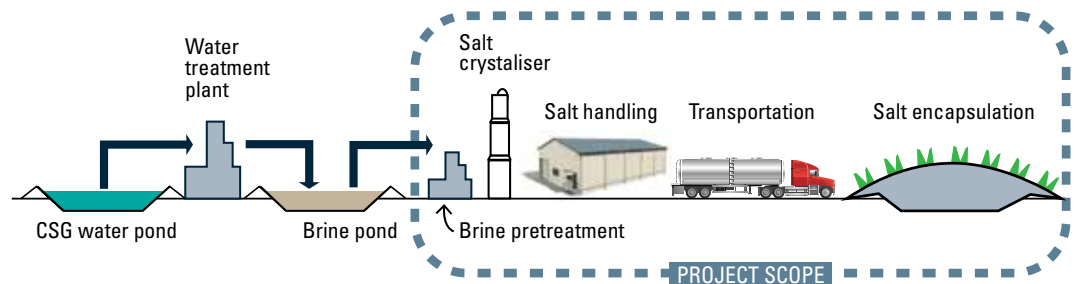
The pipeline infrastructure for the transport of brine is significantly more expensive than potable water or water infrastructure because it must be specifically engineered to a much higher standard to ensure containment and minimise corrosion. From an economics perspective, this solution is very inelastic with regards to varying brine volumes. The cost of other solutions such as SSR or salt encapsulation are much more flexible and adaptive to increasing or decreasing brine volumes. The NPC for the option based on the pipeline construction costs alone is \$765 million.

6.3.6 Feasibility of salt encapsulation

6.3.6.7 Overview

Salt encapsulation involves the conversion of stored brine to a mixed salt using a mixed salt crystalliser for long-term storage and containment in salt encapsulation cells (see Figure 9).

Figure 9: Salt encapsulation schematic



Brine stored in brine ponds would be processed through a mixed salt crystalliser MSC to evaporate water from the brine. The distillate (water with less than 50 mg/L TDS) produced from the mixed salt crystalliser would be sent back to the water treatment plant for beneficial reuse. The brine slurry exiting the crystalliser would be cooled down to ~50°C to allow for safe handling and dewatered further (to approximately 15 per cent moisture content to ensure the salt is suitable for transportation and storage). The resulting mixed salt would then be transported a short distance by truck from the salt handling facility via sealed roads to the salt encapsulation cells for storage.

The salt encapsulation cell design would incorporate a multi barrier system design to mitigate against the potential release of any salt. The design is consistent with the design requirements of regulated waste cells in common use around the world. The system consists of (from top to bottom):

- a primary leachate collection system
- a primary barrier system composed of two geosynthetic liners and a natural soil barrier including in built sensors to ensure performance is maintained
- a leak detection system
- a secondary barrier system composed of two geosynthetic liners also including in built performance sensors
- a final leak detection and groundwater diversion system.

A similar multi lined cap would be placed following filling of the cell to connect to the sidewall liners and form a complete seal. Revegetation soils would then be placed on top of the cell to complete the cap and provide a safe and suitable final surface allowing the cell to blend into the surrounding environment.

The service life for the SE cells takes into consideration the multiple barriers which form part of the cap, sidewall and basal liner systems and the selection of specific barrier materials to provide long term containment and durability required. When implemented together with a comprehensive maintenance and monitoring system facilitated by the

inbuilt sensors and multiple drainage systems, this provides for continual assurance of the performance of the cells. The service life of the SE cells therefore extends into the foreseeable future which will be measured in hundreds of years.

Industry collaboration occurred around both the design of the salt encapsulation facility and also the location of each facility. Three main collaboration options were considered:

- 1 Regional encapsulation facilities for each proponent adjacent to brine ponds or within brine ponds that are no longer required for brine storage, with consistent standards for the design of the salt encapsulation cells.
- 2 Two shared encapsulation facilities: an eastern and western facility.
- 3 A single regional encapsulation facility potentially designed, constructed and operated by a third party.

6.3.6.8 Feasibility assessment

Health and safety and environment assessment

The design of the proposed facilities sought to manage the health safety security and environment concerns of each proponent and the gas industry as a whole. In particular:

- the salt crystallisers transfer any useable water recovered as part of the salt crystallisation process back to the WTPs for beneficial use (this becomes a challenge for a single or two facility option that is not located adjacent to a water treatment plant)
- the mixed salt produced can be safely stored within salt encapsulation cells and may be suitable for reuse at a later date
- overall the SE facility would use less power and gas, and generate less emissions than an SSR plant
- the facility has been designed specifically to reduce all potential safety risks including exposure to hot brine through applying cooling methods before handling is required and minimising onsite transportation movements
- the facility has been designed to meet noise emissions management conditions.

The assessment found that the health safety and environment risks increase for encapsulation options 2 and 3. This increase in risk is associated with the transport risk associated with moving brine or salt through the landscape from each water treatment plant to the salt encapsulation facility. As the number of facilities decreases the distance that brine needs to be transported through the landscape increases. Consideration was given both to transport brine by pipeline or by trucking salt. The length of pipeline required for a single salt encapsulation facility exceeds 500km compared with 70km of infield pipelines for regional salt encapsulation facilities. The Health and Safety risks associated with trucking of the brine were considered challenging as the trucking of salt at 15 per cent moisture content would require with a significant number of truck movements along private roads. Further as the number of facilities reduces the potential for business interruption from a facility outage increases. The single facility option represents a similar risk to SSR for the potential to impact on gas production.

The HSSE risks are lowest for the regional salt encapsulation facilities option for each gas company and these are considered to be manageable.

Technical feasibility

The SE solution consists of two main components (crystallisation and storage), each of which has been used in numerous facilities worldwide. The crystallisation technology used in the salt crystallisers is used in over 100 projects operating globally. As a consequence, there are a number of technology suppliers with strong track records for design and operations. The SE cell designs have also been applied in industries producing wastes significantly more hazardous and toxic than the mixed salt produced by the crystallisation process for brine.

The key consumables for SE include the liner materials used in construction of the cells and diesel for the truck transportation from the salt crystalliser. As such, the SE will consume a much lower level of utilities and chemicals per megalitre of brine processed as compared to SSR.

Both the salt crystalliser and SE cell operations are well understood and there are only minor operational modifications necessary to take account variations in brine feed composition. From a technical perspective, the proven technology used means that SE represents a robust and flexible process that can be operated efficiently to meet requirements.

Pipeline integrity

The pipeline infrastructure required for the transport of brine must be specifically engineered to ensure containment and minimise corrosion over the lifetime of the gas industry. Suitable pipeline materials are available but will add significantly to the costs of the pipeline compared with a potable water or water pipeline. This results in significantly increased costs for a single or eastern and western facility compared with regional salt encapsulation facilities.

Delivery timeframes

The SE facility incorporates proven technologies and materials readily available on the current market. For this reason, there is a considerable amount of certainty over the delivery timeframe for each SE facility. However, the delivery timeframe certainty reduces as the number of facilities is reduced due to the requirement to construct increasing lengths of brine pipeline. Industry investigations have determined that there is an extensive construction and procurement period associated with the brine pipelines which would significantly increase the schedule risk around a whole of industry solution based on a single or two salt encapsulation facility solution when compared with that for regional facilities.

Social acceptance

A moderate level of community concern is anticipated over the disposal of regulated waste in the area surrounding the encapsulation facilities particularly if there is a potential for the facility to take other forms of waste. This concern could be reduced if the facilities are located on land owned by the gas companies which is adjacent to existing brine ponds, and increased understanding of the technology that would be used for encapsulation.

The level of concern is likely to increase significantly for a single or two facility industry solution due to the requirement for hundreds of kilometers of infield pipeline to be constructed (across strategic cropping land and other sensitive areas) and operated to transport high salinity brine from brine ponds to the encapsulation facility.

Compliance with government regulations

The encapsulation option is a disposal option and so is therefore a least preferred solution in the water policy (DEHP 2012), however it is considered that it would comply with the policy if no feasible beneficial use options could be identified.

Economics

Regional encapsulation facilities constructed adjacent to brine ponds or within brine ponds that are no longer required for brine storage have been shown to be the most economic brine management solution for each proponent.

The economics for a whole of industry solution based on a single or dual encapsulation facility are significantly worsened due to the requirement to construct and operate hundreds of kilometres of pipeline infrastructure for the transport of brine. The pipeline materials and construction costs are significantly more expensive than potable water or water infrastructure because it must be specifically engineered to a much higher standard to ensure containment and minimise corrosion.

This solution has considerably lower cost, greater flexibility and less schedule risk than the ocean outfall solution.

7 Conclusion

The continued development of petroleum resources in Australia is important for energy security, economic development and growth. There are significant climate benefits in transition to increased use of natural gas.

The Australian oil and gas industry takes its commitment to protect water resources seriously and employs the highest standards in operations and well design. The risks associated with oil and gas extraction in Australia are managed under a comprehensive regulatory framework that ensures all risks are considered and managed. The oil and gas industry is arguably the most highly regulated users of water in Australia, despite not being the biggest water user.

Queensland's gas industry is a major supplier of desalinated water that is in high demand by communities and agricultural producers.

Since 2012 the gas industry has been taking a whole-of-industry response to the management of the brine and salt by-product from water treatment. The industry has collectively expended in excess of \$100 million on investigations to identify the most feasible solution for the long-term management of brine and salt.

Initial preliminary studies into beneficial use options culminated in selective salt recovery being identified as the most likely candidate for a whole of industry beneficial use option. However further detailed investigations showed that this option is infeasible as:

- the SSR technology has not been demonstrated at a commercial scale, and the technology vendors would not provide plant performance guarantees, leaving the gas industry with significant risk that could only be eliminated by also constructing a salt disposal facility
- the SSR technology has the highest up front and lifecycle costs of any of the brine management options considered
- the adoption of SSR would result in significant additional resource (energy) consumption and negative environmental and social impacts
- entry of new salt into the market place would also likely cause displacement of existing established suppliers from the market, as market research did not identify any unmet demand for salt.

Three disposal options were the subject of industry collaboration for brine and salt management these being brine injection, ocean outfall and encapsulation.

Brine injection was found to be infeasible as the industry has been unable to find an injection target with sufficient permeability and capacity, which ensures geological isolation from sensitive receptors, and mitigates the risk of induced geomechanical changes.

Of the two technically feasible brine management disposal options encapsulation facilities located adjacent to each of the gas companies' brine ponds, or within brine ponds which are no longer required for brine storage, has the smallest land disturbance area of the options. It has minimal technical risk and has the lowest overall cost of any of the options considered, and allows maximum flexibility for development in line with each gas companies' brine production. The risks and costs for a single or dual encapsulation facility as a whole of industry solution increase significantly compared with encapsulation facilities which are sited next to brine ponds due to the requirement to construct and operate hundreds of kilometres of brine pipelines.



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