Life Cycle of Coal Seam Gas Projects: Technologies and Potential Impacts

Report for the New South Wales Office of the Chief Scientist and Engineer

Professor Peter J Cook CBE, FTSE

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Disclaimer

This report provides general information on the geology, technology, engineering methods, potential environmental or other impacts that might be associated with coal seam gas projects. Examples are provided from specific projects for illustrative purposes, but this report should not be used to assess any project or the technologies deployed by that project. Nor should the report be used for assessing the impact or potential impact of any existing or future CSG project, nor for assessing resources or reserves or any other economically significant aspect of a CSG project.

Acknowledgements

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Scope of the Report

In order to address a number of key issues relating to CSG in New South Wales, the Office of the Chief Scientist and Engineer has requested a report covering the following areas:

A. The CSG project life cycle including:

1. Exploration
2. Assessment (including pilot well testing)
3. Production
4. Suspension, Closure and Abandonment
5. Storage, processing and transport of gas

B. Factors that contribute to site selection for CSG activities, including characterisation of geology, resource and environmental impacts; drilling and construction activities; operations; waste management.

C. How different geological conditions impact on the different stages of CSG development (e.g. wet versus dry coals; stress regimes; rock types; depth; the difference between NSW and Queensland coals).

D. How changes in technology have impacted on the economics and dynamics of CSG extraction; and on the general effectiveness of current technologies used.

E. Potential impacts that can occur at each stage of CSG development (outlined in A, above), including:

1. Fugitive emissions
2. Chemical release (from hydraulic fracturing and the seam)
3. Infrastructure (including roads, well pads and pipelines)
4. Cumulative impact

F. Techniques used for fracture stimulation and for assessing well integrity, including:

1. The differences between fracking in CSG vs shale gas vs other applications (eg. pressures, fracking fluids used, risks),
2. Systems used to assess, prevent and manage the risk of connectivity (or impacts from connectivity) between the coal seam and surrounding aquifers during fracking
3. Techniques to monitor the progress of a hydraulic fracture (including benefits and short comings of the techniques)
4. Techniques to assess well integrity (including benefits and short comings of the techniques)

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INTRODUCTION

What is Coal Seam Gas?

Coal seam gas (CSG), like all forms of natural gas, is composed predominantly of methane (CH4), with minor amounts of carbon dioxide, nitrogen and inert gases. Natural gas occurs in various geological environments which provide the basis for classifying the gas as "conventional" (gas produced predominantly from porous and permeable sandstones) or "unconventional" (shale gas produced from deep brittle shales, tight gas produced from low permeability sands and coal seam gas produced from coals). The geological settings for these various types of gas are illustrated schematically in (Figure 1).

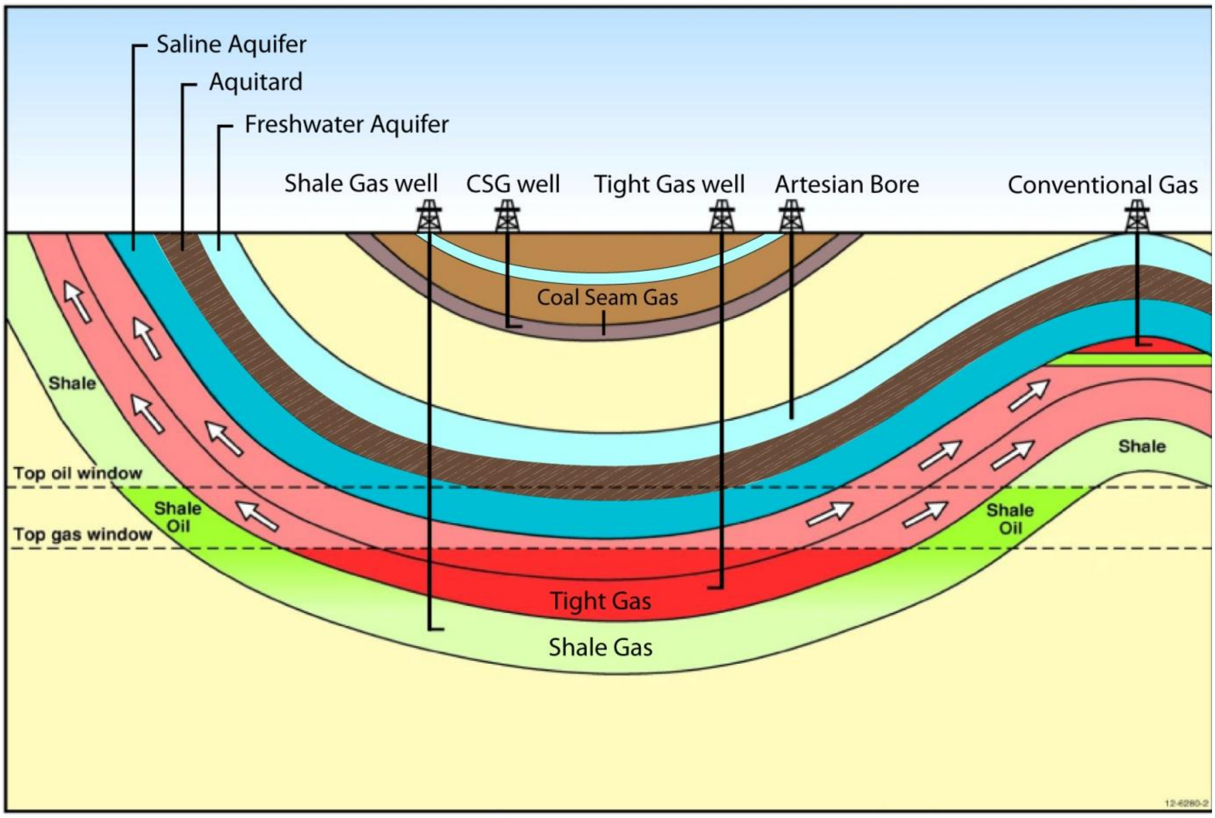


Figure 1. The geological setting of various types of conventional and unconventional gas resources within a sedimentary basin.

Unlike conventional gas (or oil) or tight gas, which migrate from the source rock to the reservoir, in the case of CSG, coal is both the source and the reservoir, with the gas trapped in the coal either by adsorption on the fine organic material that makes up the matrix of the coal or as free gas in fractures within the coal. The coal can range in age from a few tens of millions of years to hundreds of millions of years, and from a few metres thick to tens of metres thick. It is normally found at depths of less than

1000 meters which is somewhat shallower than conventional gas and therefore it is often somewhat cheaper to produce. Most (though not all) coals have low porosity and low permeability, which is why many of them need to be dewatered and/or less commonly, hydraulically fractured to enable the gas to flow. These and related features are discussed in greater detail later in this report.

Until recently, most of the gas used in the world was conventional gas, but increasingly in Australia and elsewhere, unconventional gas, particularly CSG, is now being produced and it is apparent that the CSG reserves are very large (see later discussion). To date, most of Australia's CSG resources and reserves are in eastern Australia, with the majority of the production and most of the identified reserves in Queensland, with a large proportion of the Queensland gas projected to be used by the liquefied natural gas (LNG) industry (Figure 2).

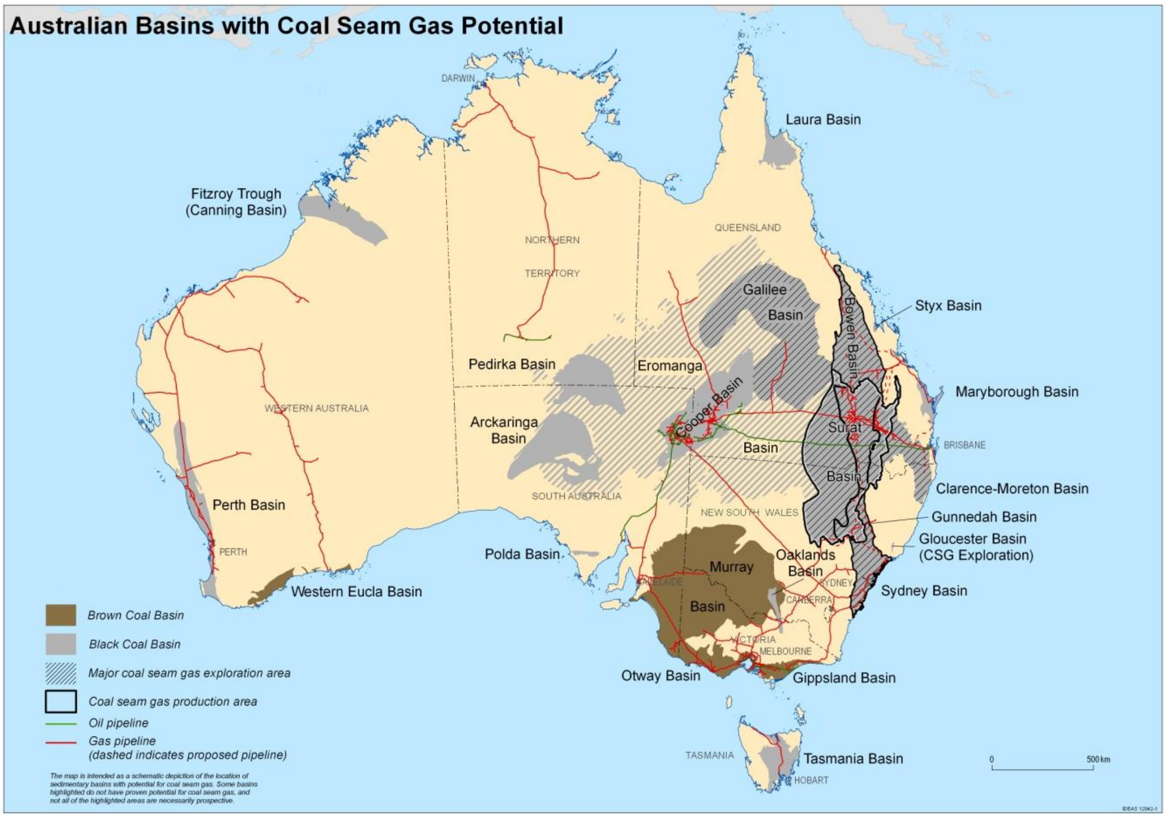


Figure 2. Australian basins with coal seam gas potential (Source: GA)

CSG was first produced commercially in Australia from the abandoned Balmain Colliery in Sydney in the period 1935-1946 (Miyazaki, 2005). Commercial scale CSG has been produced in New South Wales for a number of years, primarily for supplying power for water and space heating for industrial, commercial, and domestic users, along with fuel for stoves as well as industrial facilities and gas turbines to generate electricity. A number of NSW coal mines are quite high in methane and for many years it has been necessary to extract the gas prior to them being mined, to minimise the possibility of a dangerous build-up of methane in the underground workings. Several of the NSW sedimentary basins are rich in coal and CSG and there is a high level of interest by the gas industry in exploring for, and producing more CSG in NSW. Whilst there is a recognition that this could result in economic benefits accruing to the State, it has also given rise to a number of questions regarding the potential impact of CSG production on the environment (see later) and a cautious approach to the granting of exploration or production licences.

Where does CSG occur in New South Wales?

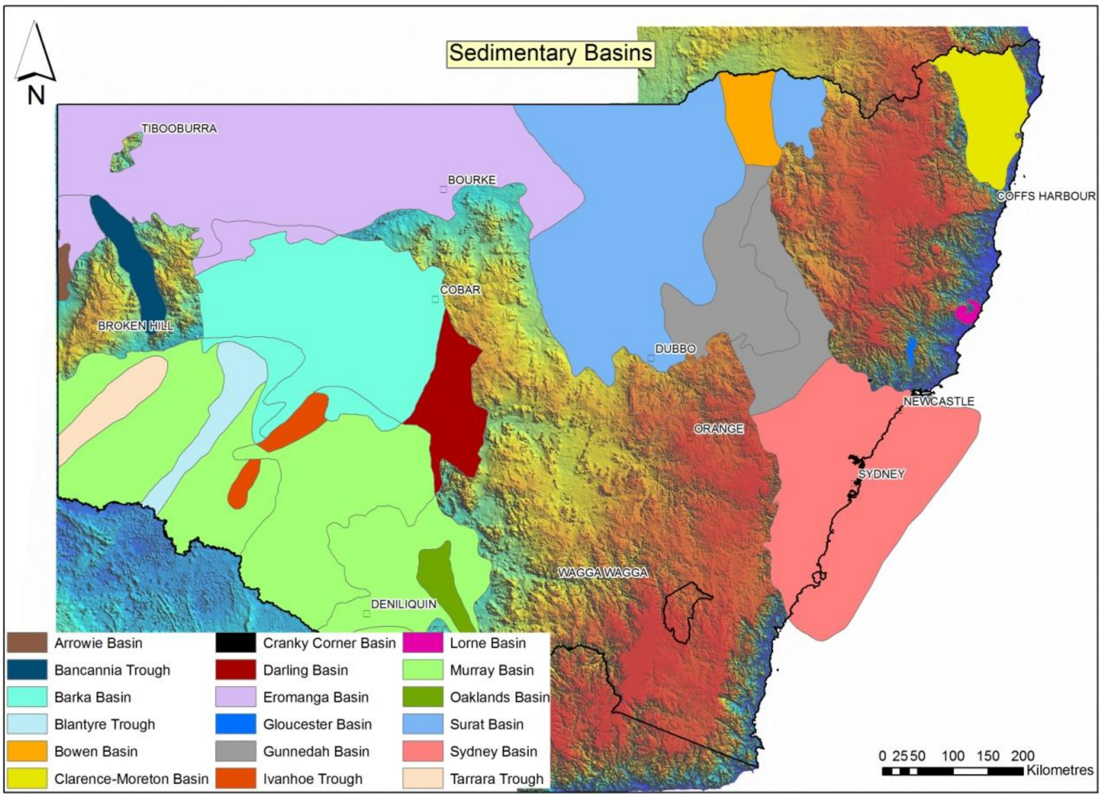


Figure 3. New South Wales sedimentary basins (Source: Golab, 2010)

Sedimentary basins can range in sediment thickness from just a few hundred metres to thousands of metres and they can underlie areas of just a few hundred square kilometres to hundreds of thousands of square kilometres. CSG occurs in a number of sedimentary basins in New South Wales, though not all. The sedimentary basins of New South Wales are shown in Figure 3 (after Scheibner and Basden, 1996 and Golab, 2010). From the perspective of CSG, the basins of interest in NSW are:

- The Clarence-Moreton Basin, which is an extensive Mesozoic sedimentary basin, with Triassic-Jurassic continental (non-marine) sediments containing abundant coals, which unconformably overlie Ordovician to Triassic sediments, metasediments and igneous intrusions. There have also been a number of late stage igneous bodies that intrude on the coal bearing sediments in places. The Basin is divided by structural highs into Cecil Plains, Laidley and Logan Sub-basins, and the Casino, Lismore, Grafton and Yamba Troughs. The Basin contains extensive coal systems; namely the Walloon, Ipswich and Nymboida Coal Measures. Some of the deep coal seams are high rank and contain CSG. NSW DPI estimates the potential recoverable CSG reserves of the Clarence-Moreton Basin to be 215 billion m^3 (based on a 20% recovery factor).

- The Gloucester Basin contains a thick sequence of Carboniferous volcanics that are conformably overlain by intensely faulted coal-bearing Permian sedimentary rocks of the same age as Sydney Basin sediments. The Basin contains coal systems and significant amounts of coal seam gas.
- The Gunnedah Basin consists of coal-bearing sediments overlying the weathered surface of the basement volcanics in the south, and unconformably overlying deformed and metamorphosed older sediments elsewhere. The Basin is subdivided by basement ridges into a series of troughs and sub basins. The Basin contains coal systems with high porosity and permeability values and significant amounts of CSG. NSW DPI estimates the potential recoverable CSG reserves of the Gunnedah Basin to be 146 billion m^3 (based on a 20% recovery factor).
- The Murray Basin contains a thin sequence of Cainozoic consolidated and unconsolidated sediments, that unconformably overlie and onlap much older sediments. It is underlain in places by a number of infrabasins containing Permo-Carboniferous, Triassic and Cretaceous sediments with coals, such as the Oaklands Infrabasin though in general the coal is low grade and shallow and has limited prospectivity for CSG.
- The Surat Basin is a large basin of Jurassic-Cretaceous age in the northwest of the state, with coal bearing sediments that are especially well developed in Queensland but extends south into NSW. In general the coal sequences in NSW are sporadic, shallow, have low permeabilities and are not well developed although in Queensland, the basin contains major CSG reserves and resources, especially in the Walloon Coal Measures.
- The Sydney Basin contains Permo-Triassic clastic sediments with many coal intervals. It overlies Lachlan Fold Belt strata and is divided by ridges and hinge lines into the Illawarra Shelf, the Blue Mountains Shelf, the Macdonald Trough, and the Lake Macquarie Trough. The Basin contains extensive coal systems continuing to great depths and containing significant amounts of CSG, which is already being produced near Camden in the Sydney Basin. The NSW DPI estimates the potential recoverable CSG reserves of the Sydney Basin to be 150 billion m^3 (based on 20% recovery factor).

CSG-bearing coal seams can be underlie areas of just a few tens or hundreds of square kilometres to thousands of square kilometres and individual coal seams can range in thickness from a few meters to tens of meters. In some basins there may be just one or two coal seams; in others, for example the Sydney Basin, there may be multiple seams (Figure 4) each with their particular properties and potential for CSG. Most CSG is extracted from depths of less than 1000m. Whilst there are many common features between basins in the mode of occurrence of coals and CSG, there can also be important differences that reflect the depositional and post depositional history of the basin. This Report does not attempt to deal with the detail of each sedimentary basin, but sets out the common features of CSG deposits, the technologies deployed to extract CSG and some of the potential impacts of that extraction.

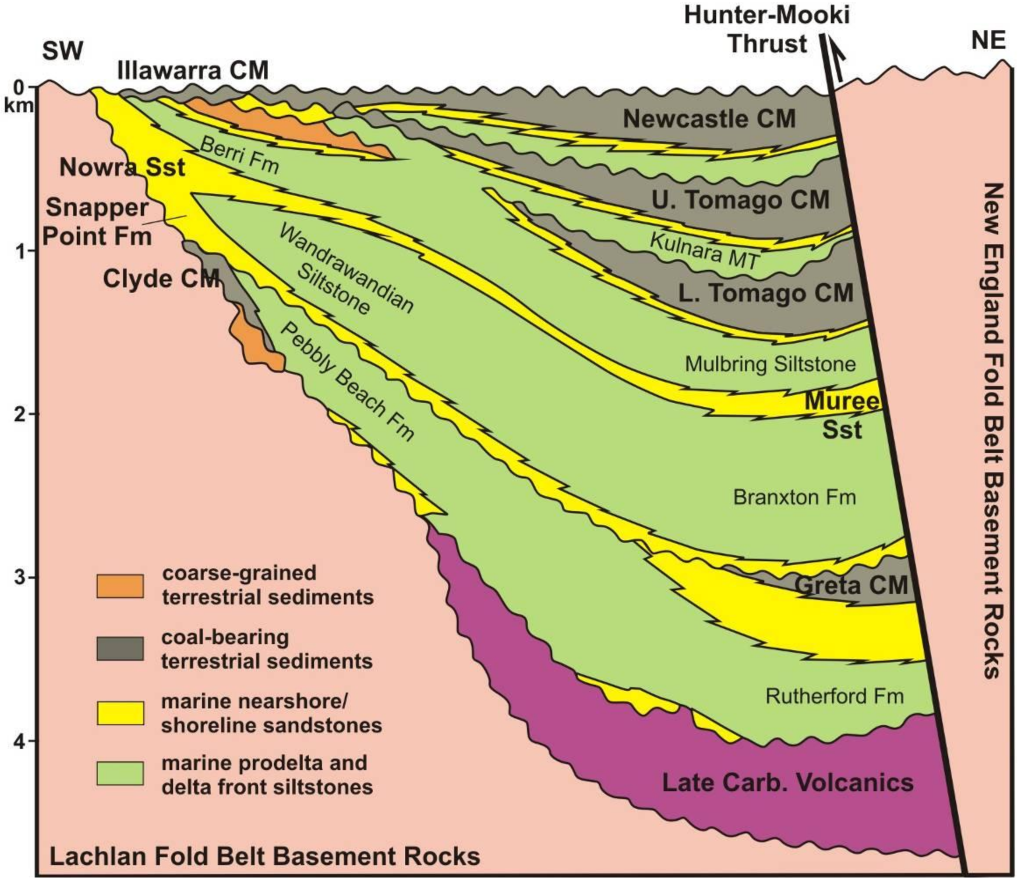


Figure 4. Schematic stratigraphic cross section of the Sydney Basin, showing multiple coal seams. (Source: Golab 2010)

A. DEVELOPMENT OF A PROJECT

Before reviewing the specifics of a CSG project, it is useful to consider the approach taken to project development and implementation in general.

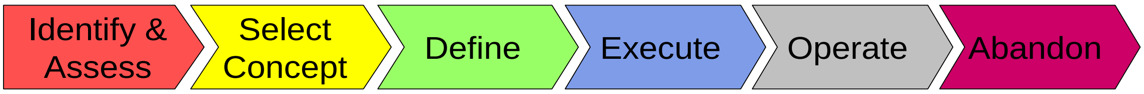


Figure 5. The stages of a resource project.

Developing any sort of major construction, engineering or energy project usually follows a fairly well established pathway (Figure 5) that enables the project to proceed in a logical and effective manner. At each stage, there will be decisions to be made regarding finance, markets, economic forecasts, technical feasibility and so on, based on the evidence available to the project proponents at that time. In some instances, the information on which a decision will be made may be clear and unequivocal, such as a firm and enforceable agreement signed to purchase a product, or the right of access to an area of land that is required for the project. Sometimes the information may be more speculative, such as future market projections or the prospect of getting a waiver from having to meet a particular regulatory requirement. These may have a high degree of uncertainty attached to them, which may in turn impact on investment confidence. If investors do not have the necessary level of confidence to proceed to the next stage, then the decision may be made to delay proceeding any further down the decision path until more information is obtained, or a greater degree of confidence secured. Alternatively, the decision may be made to not proceed with the project at all, because there is too much uncertainty attached to it or little prospect of a successful commercial outcome.

Therefore having sufficient confidence (often referred to as de-risking) all along the decision pathway in order to make the required investment, is critical to any major project proceeding. This also defines how the project actually moves ahead, the rate at which it proceeds and the rate at which money is spent. That then is the general approach taken by most projects to the high level issues of finance, economics and markets. But of course there are also other quite fundamental questions that are at least as important in major projects that have to be asked as part of the decision–making process: Is there likely to be an impact on the environment, and if so, how can it be avoided or minimised? Is the project safe? Are the regulatory approvals in place? Is there a social licence to operate? Alternatively is there evidence that the community is, or will be supportive of the project?

Obviously each of these and many other questions, have a degree of uncertainty attached to them and all will require actions to minimise that uncertainty so that the project can proceed to the next stage. In fact, the project pathway is not a single unidirectional and sequential process with one question being asked and resolved before dealing with the next question. Very often a series of questions are pursued in parallel and concurrently. These may only come together when a particular decision point, or stage gate, is reached, at which time a whole range of issues may need to be satisfactorily addressed (or the uncertainty surrounding them reduced to an acceptable level) before proceeding to the next stage.

Putting this in the context of a CSG project, there are a number of key stages which are outlined below, but there is also a regulatory overprint that also drives the process. There are of course a great many approvals required from a variety of government departments. However the major regulatory milestones commence with first an application to the Government for an exploration licence (PEL), which is followed by an assessment lease (PAL) and then by a production lease licence (PPL). However in some circumstances, it is possible to proceed directly from a PEL to a PPL, subject to government approval. Approval is also required to cease production and abandon the well at the end of the project and throughout there are many regulations that have to be considered and addressed.

What is the timescale involved in all of this? It is difficult to answer this question as every project is different and there are many variables. But the exploration stage might last for two years or more; fully assessing the resources and establishing the reserves could take five years or more; bringing all the facilities on stream is dependent not only on the time to construct them, but also the time (which can take some years) to get all the approvals in place. The field might then produce CSG for 20 years or more. Finally, once the wells are plugged and abandoned, there may be a requirement on the company to monitor the field or the site for several more years. Therefore a CSG project and the stages outlined in Figure 5 may extend over 30-40 years.

CSG projects follow this general trajectory in terms of project stages, regulatory processes, construction and approvals; but at the same time every CSG project is different, depending on a range of variables such as the location, whether or not there is existing infrastructure, the rate at which the gas can be produced, the prospect of adverse environmental impacts, whether there are impurities in the gas and even what is the end use of the gas—domestic, commercial, electricity production or LNG. These and many other issues have a major impact on the nature of the project as it proceeds from exploration and assessment to production and ultimately through to closure and abandonment. Each of these steps will now be considered.

A.1 EXPLORATION

Exploration for CSG is very dependent on developing a comprehensive understanding of the rocks in which the CSG is likely to occur, the manner in which the gas might have been generated and also whether a promising area is available for exploration. Before exploration can commence, the exploration company must first obtain an exploration licence (PEL) from the relevant authority (the NSW Minister for Resources & Energy) under the Petroleum (Onshore) 1991 Act. An environmental assessment is required at the exploration stage. Various conditions are likely to apply regarding the conduct of the exploration program, including noise, access and water.

Exploration, which is undertaken in areas where there are no known CSG deposits, is termed “greenfields exploration”. Where there are already CSG deposits known, the exploration in those areas is known as “brownfields exploration”. In New South Wales, CSG is known to occur in commercially significant quantities in the Sydney, Gunnedah, Clarence-Moreton and Gloucester Basins (Figure 3) and as a starting point, most explorers commence their work in one of these basins if areas are available for exploration. Not all areas are available for exploration in these basins, or companies choose not to explore in them for a range of reasons, such as dense urban development or environmental sensitivity (Figure 6). There are some unexplored or underexplored areas of NSW which might be promising for CSG, such as some areas underlying the Murray Basin or perhaps parts of the Surat Basin, but they would be regarded as “high risk” areas from the point of view of the likelihood of exploration being successful—in other words the prospect of a successful economic discovery are rated as low.

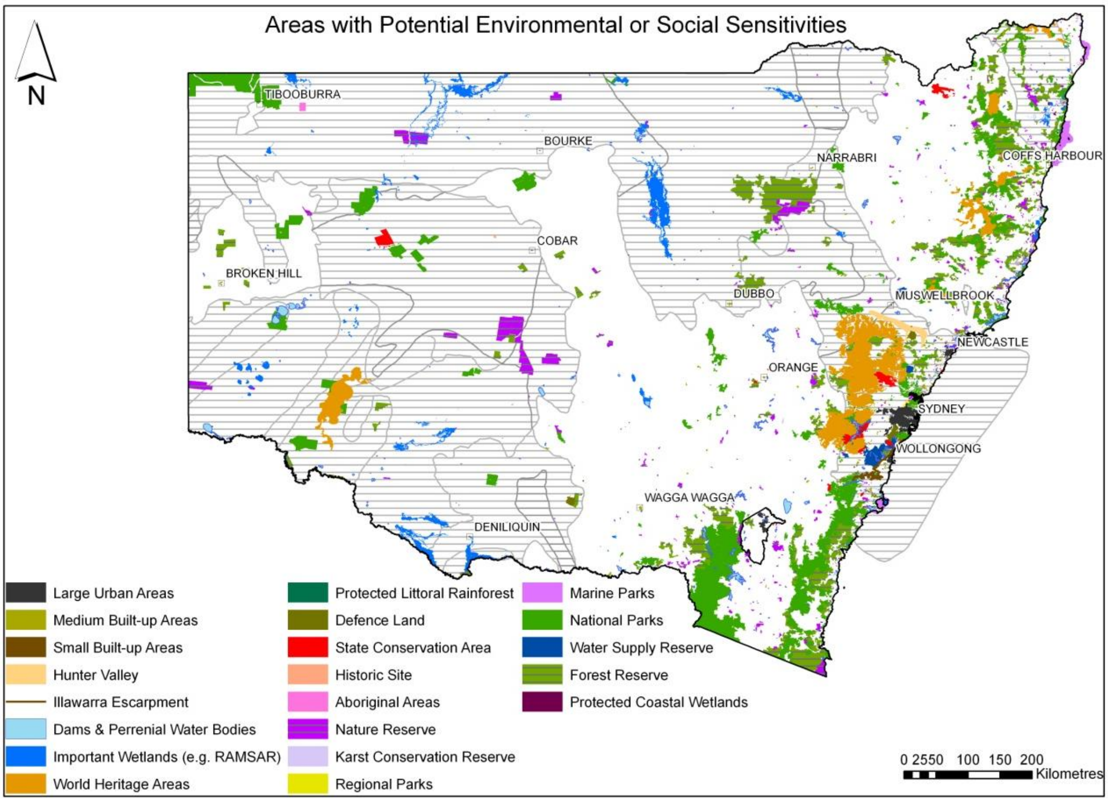


Figure 6. Areas of New South Wales with potential environmental or social sensitivities. (Source: Golab, 2010)

Geological parameters

The general geological setting of a basin, or parts of a basin, is an important exploration consideration in any sedimentary basin; if a basin is known to be structurally very complex with intense folding and faulting, perhaps as a result of being deeply buried, then the rocks may be too highly “cooked” for methane to remain in the rocks in commercial quantities. Where they are flat-lying, shallow and undisturbed, they may be immature and methane may never have been generated. Therefore one of the first prerequisites is that the geological history of the rocks is favourable for methane generation and trapping.

Where there is little or no existing information, the explorer may start by undertaking a desktop study of an area to establish its “prospectivity” – the prospect or likelihood of a commercially significant deposit being found. This may be based on a geological model, such as whether the basin is likely to have been suitable for the formation of coals. Coal is formed from plant material in ancient peat swamps on river floodplains, deltas, coastal plains and lakes. The geometry of the coal deposits is directly influenced by the nature of the original sedimentary environment, which in turn influences the way in which the exploration program is undertaken. Conversely coal is never found in deep marine basins but it can be found on the margins of the ocean, in what was perhaps a coastal plain setting.

In a coal-forming environment, peat forms initially, then lignite (brown coal), followed by sub-bituminous (low rank) black coal. As the coal is buried deeper under more sediment, it becomes progressively higher rank, generating gas (thermogenic gas) as the sediments become thermally more mature. This production of methane is part of the normal process of "coalification" as a result of increasing temperature and pressure. In general, the deeper the basins and the higher the rank of coal, the greater the proportion of thermogenic gas. Where the coals remain at shallow depths or are uplifted to shallower depths over the past few million years, bacteria (introduced from shallow meteoric groundwaters) can break down the coal, forming biogenic methane. If there is carbon dioxide present, then the bacteria can also break that down to form methane. Biogenic methane has been found down to depths of 1000m, but is usually only a major component at depths shallower than approximately 600m where biogenic methane can provide significant enhancement of the CSG content of the coal seam. This late-stage enrichment can be an important component of the exploration model and the exploration program. The action of methanogenic bacteria can also produce a positive outcome in terms of the gas composition in that, as mentioned previously, they break down not only the coal but also the carbon dioxide, so that CSG with a high biogenic content tends to be low in CO_2.

Because of the significance of groundwater to the occurrence of biogenic methane, an important part of a CSG exploration program, is understanding the palaeohydrogeology of the basin and the scope for biogenic enrichment. In areas such as the Gunnedah Basin, enrichment in CSG by biogenic activity is targeted in exploration programs. The post-depositional thermal history can also be important. For example, magnetic anomalies serve to identify areas which should be avoided because there has been late-stage volcanic activity, which is likely to have introduced large quantities of carbon dioxide into the rocks and the CSG, significantly decreasing the value of the CSG and in extreme cases, rendering it unusable because the CO_2 content is so high.

Coal types

The age of the basin can be significant in developing an exploration program. Older coals (e.g. Permian coals of the Sydney basins) generally have been deeply buried and often have a higher gas content. But they commonly have low permeability and porosity and are "drier" coals, which may result in a lower rate of gas production. This may require more expensive production techniques to counter the low permeabilities. Younger coals, such as the Jurassic coals of the Surat Basin, may have a lower gas content, but their greater permeability and porosity (which tends to make them wetter coals) results in a higher gas flow, which makes them economic in Queensland, though—to date—not in NSW. However the coals are also thinner and more discontinuous than the older coals which can make them more difficult to develop as a CSG prospect.

The rank of the coal (a measure of its maturity) has an influence on its potential as a source of CSG. Maturity is measured by determining the vitrinite component (and reflectance) of the coal; the higher the vitrinite content of the coal, the higher the likely gas content of the coal. Conversely, brown coals such as the young Cenozoic coals of the Murray Basin, are generally too low in rank (low in vitrinite) for economic thermogenic CSG but they may contain some biogenic CSG, though perhaps not in large quantities.

As discussed earlier, the rank of the coal also appears to influence the composition of the CSG, with low rank coals containing methane and very little carbon dioxide. Higher rank coals tend to contain a greater proportion of carbon dioxide in the CSG, but the composition can be laterally quite variable. In the Sydney Basin for example, the CO_2 concentration increases upwards through multiple coal seams (Faiz et al, 2007) and the ethane concentration in the Bulli seam, whilst generally low, also similarly varies with depth. But as pointed out earlier, there are also many other factors that influence the composition, notably late-stage volcanic activity (to produce high CO_2 gas) or the impact of late-stage meteoric water and related bacterial action (to produce low CO_2 gas).

Permeability is related to coal rank and also to the stress conditions. Coals with a high vitrinite content will tend to have high permeabilities. As rank increases, the fractures or cleats within the coal also increase, thereby increasing fracture permeability. Conversely, increasing rank can decrease matrix permeability, probably due to changing pore size. There is therefore a complex interplay between these permeability properties which can markedly affect the economics of CSG production (Wang and Ward, 2009). In addition there is a general trend of permeability decreasing markedly with depth, with Moore (2012) reporting that coal at 100m depth may have permeability of hundreds of millidarcies, whereas that same coal at a depth of 1000m may have a permeability as low as 1-2 millidarcies.

Therefore a promising exploration area for CSG may require that the coals are thick, continuous, not geologically too disturbed, high rank and at 200-1200m depth. In addition they should be permeable, have a favourable stress field and abundant adsorbed methane or abundant free methane in the cleats. Finally, if the hydrogeological evolution of the basin has provided the opportunity for biogenic activity, then this can produce significant upgrading of the CSG content and decrease the CO_2 content. Obviously few seams have all these features and therefore there is always a compromise to be made or new extraction techniques employed (such as hydraulic fracturing) in taking an exploration prospect forward.

Field exploration

Once this early stage of exploration has identified a promising area and an exploration licence (PEL) granted, then the company is able to undertake field work. It is often at or just before this stage that the community will become aware that there is a CSG project in their area. Because minerals are vested in the Crown in NSW (and in all other states in Australia), it is the State which grants the exploration licence under certain conditions, such as those relating to environmental impact, access, landholder rights, remediation etc, and unlike the desktop stage (which is usually undertaken on a confidential basis because of commercial sensitivities), usually involves people and equipment being active in the exploration area. This could mean a low impact activity such as conventional geological mapping where there are rock outcrops to be visited, together with air photography and remote sensing. It may also involve greater impact activities such as geophysical surveys, for example gravity or magnetic surveys, to determine the subsurface geology of the region or basin. In some areas this sort of surveying may have already been carried out by the Mines Department or Geoscience Australia; in other areas it is necessary for the exploration company to undertake ground or airborne surveys. In some cases the company may undertake a seismic survey to determine the structure of the rocks in the subsurface, which can involve some significant land disturbance due to the sound source used for the survey (such as a vibroseis truck, or small charges of dynamite) or the laying out of seismic cables and geophones). Geochemical surveys can also be undertaken as an aid to exploration. For example so-called “sniffer” surveys can detect natural surface leaks of methane, which in turn may indicate commercially significant accumulations of CSG in the subsurface. Geochemical surveys of existing water bores may also be undertaken, to detect any abnormally high levels of natural methane in the groundwater – again another potential indicator of subsurface accumulations of CSG.

Some or all of these field exploration activities are then integrated with laboratory information and geological and geophysical modelling, to develop exploration targets, which can be tested by drilling. There are more detailed discussions on drilling technology in the production section of this Report (see later), but here the focus is on using the exploration well to test the exploration model and the possible existence of a so-called “sweet spot”, where a whole range of favourable parameters come together. This may involve a number of questions, some of which can be answered by drilling, sampling, coring and testing an exploration well; questions such as:

- Is coal present and at what depth?
- What is the thickness of the coal and what is its vitrinite content?
- What is the permeability of the coal?
- Is gas present in the coal and if it is, what is its composition and how abundant is it?
- What is the scope for biogenic enrichment to have occurred?
- Can a production test (of the gas) be successfully undertaken?
- What is the stress field within the well?
- What is the depth of the water table?

In fact many of these questions may only be addressed in the later stage of the program, perhaps because of the cost involved or because the information can only become available at the pilot stage (see later). Nonetheless, when possible, subsurface samples are taken from a well. For example, a core of the coal or of some of the related sediments may provide the opportunity to undertake laboratory tests, such as the vitrinite reflectance, or enable the age of the coal to be established. However coring of sediments can be difficult and expensive and for this reason, samples may be obtained from cuttings – fragments of rock resulting from the drilling process, which are then circulated to the surface by the drilling mud, where they can then be collected. Most CSG exploration wells are also geophysically logged, using a range of sophisticated downhole instruments. These instruments are used to determine a range of physical and chemical properties of the rocks intersected in the well including the acoustic, electrical resistivity, and thermal properties as well as the natural radioactivity of the rocks, the stress and fracture patterns and the stability of the well. The groundwater in the exploration well will probably also be sampled and measured to determine its composition and the flow rate.

By integrating this diverse range of information, an accurate picture can then be developed of the subsurface conditions in the vicinity of the well and the prospect that the exploration licence area in general may be promising for CSG – or not. If not, then the exploration company may decide to drill a new exploration well in a different area, based on the data they collected in the first well and other information, or it may decide the area is not prospective for CSG and relinquish that part of the exploration tenement. If, on the other hand, the results are promising, then the company may decide to move to the next stage of exploration of the tenement in order to establish the extent of the resource, which will require more exploration wells and additional expense.

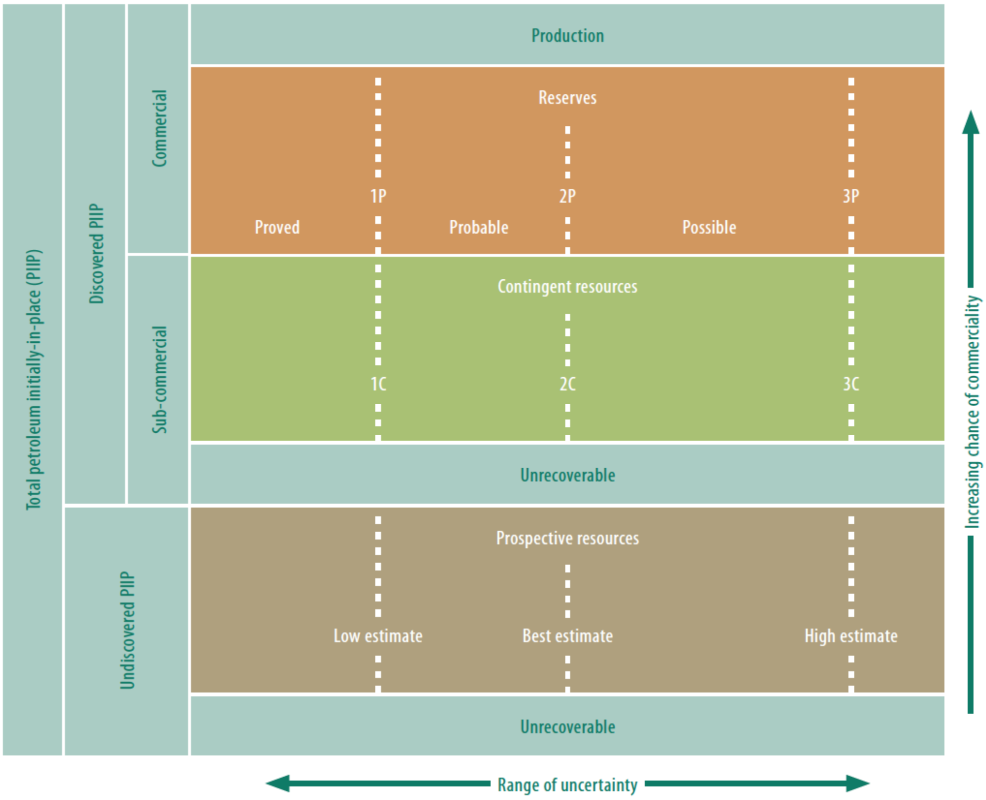
This then is the generalised process that is followed for an exploration program perhaps first in a limited area and then over an entire exploration tenement. Most geological formations and particularly coal-bearing formations are very heterogeneous. In other words, they vary laterally, largely in response to the original depositional environment. The greater the variability, the greater the number of exploration wells needed to adequately delimit the CSG opportunity.

Each CSG company will have its preferred exploration process and the tools it will use in that process, depending on its experience elsewhere and the particular features of the CSG prospect being explored. However all, to varying degrees, aim to define the gas in place and characterise the coal "reservoir" using three critical pieces of information, namely the coal volume (influenced by the depositional and the structural settings), the level of gas saturation (influenced by coal rank) and the permeability of the coal. In addition, account must be taken of the hydrodynamics of the coals and associated sediments. Together these help to define the nature of the assessment program, which is discussed next.

A.2 ASSESSMENT

As a result of an encouraging exploration program, the exploration company may now decide to undertake a full assessment of all, or the most promising parts, of the exploration licence area. This will enable the CSG project to progress from having a somewhat speculative value for the amount of CSG in the coal or coals in the area, to a more meaningful figure of how much can be extracted. In other words, the project will aim to move from having uncertain figures for the amount of CSG present, to extractable CSG figures with a high degree of confidence attached to them.

Simplistically, the confidence with which the quantity of CSG in a field can be determined and the cost of production (particularly whether or not production of CSG is likely to be economically viable), together determine whether the quantity of CSG is a "resource" or a "reserve". However, if for some reason an otherwise-economic deposit cannot be developed because, for example, an endangered species is found to occur in the immediate vicinity and drilling is not allowed by the regulator, then it may be classed as a resource. At the early exploration stage, when the quantity of CSG in situ is poorly known, perhaps only in a very speculative way, then it is called a resource. If it is known with great confidence because it has been extensively drilled and tested and it is very likely to be economic to extract the gas, then the quantity of CSG in the field is called a reserve (see Society of Petroleum Engineers (SPE), 2012 website for definitions of resources and reserves). A two-axis resource-reserve system used by the SPE is shown in Figure 7.



Source: Society of Petroleum Engineers, http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

Figure 7. The resource-reserve system of the Society of Petroleum Engineers. (Source: SPE, 2007)

A project is classified by the Society of Petroleum Engineers (SPE Oil and Gas Reserves Committee, 2011) according to its maturity or status (approximating to its chance of commercial success) using three main classes: Reserves, Contingent Resources, and Prospective Resources. Separately, the range of uncertainty in the estimated recoverable CSG is categorised based on at least three estimates of the potential outcome: low, best, and high. For projects that satisfy the requirements for commerciality, reserves may be assigned to the project, and the three estimates of the recoverable sales quantities are designated as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible) Reserves (see Figure 7). There are fundamental differences between resources (often a very large, ill-defined number, which may not be commercially significant) and reserves (a much smaller number but commercially significant).

Determining resources and reserves

The concept of reserves and resources is often represented as a pyramid (Figure 8), with the broader base of the triangle representing the CSG resource. As the resource becomes better defined and better understood and the proportion of the gas that can be commercially extracted (usually a small proportion only of the initial resource volume) can be more confidently predicted, the CSG “moves up” the pyramid with the relatively small volume at the apex representing the reserve. If the price of gas increases then the volume of the pyramid representing the reserve may increase in volume as the amount that can be extracted commercially becomes greater. If the cost of extracting the gas increases, then the volume representing reserves may decrease in size.

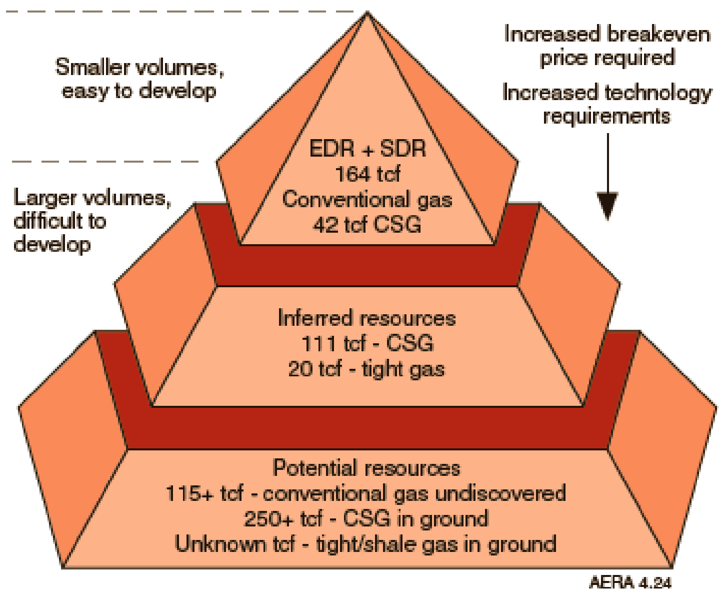


Figure 8. The resource-reserve pyramid. (After McCabe, 1998; Branan, 2008; AERA, 2010, p 100) EDR – economic demonstrated resources. SDR – Subeconomic demonstrated resources. tcf – trillion cubic feet of gas (an industry measure of reserves and resources).

If a project is going to proceed to the stage of commercial production, then a high level of confidence must be attached to reserve figures by the project proponents, by the purchasers of the gas and by the banks and the shareholders who will provide the funding to enable the project to go ahead. Therefore, the assessment phase of a project is very important in determining whether a CSG project goes into production.

In a comprehensive review of CSG by Moore (2012), the process of moving from resource to reserve certification (described as the point where science meets economics) is outlined in some detail. He points out that "in order to achieve certification at the reserve level, commercial flow rates must be demonstrated. The amount of reserves certified can be dependent on several factors including the extent of wells with gas data throughout the permit, number of permeability tests conducted and demonstrable extent of the reservoir among other factors". Arguably, flow modelling is the second most important input into the assessment process after permeability and more than 20 parameters are described by Moore (2012, Table 1, p 68) as being "essential data input values for gas flow modelling" In other words, the assessment process for CSG requires a lot of data collection and rigorous analysis if it is to have any meaning. It also requires a number of wells, although where possible, previously-drilled exploration wells are also used as appraisal wells. In addition there are many wells that have been drilled in NSW coal basins in order to delineate coal distribution which may provide information relevant to CSG assessment. For example, over 20,000 bores have been drilled in the Sydney Basin, although most of these are located around the basin margins, where the Permian Coal Measures are at the surface or at minable depths below the cover. Therefore, despite the abundance of existing wells, many of them are of limited value for evaluating CSG reserves and new appraisal wells are required.

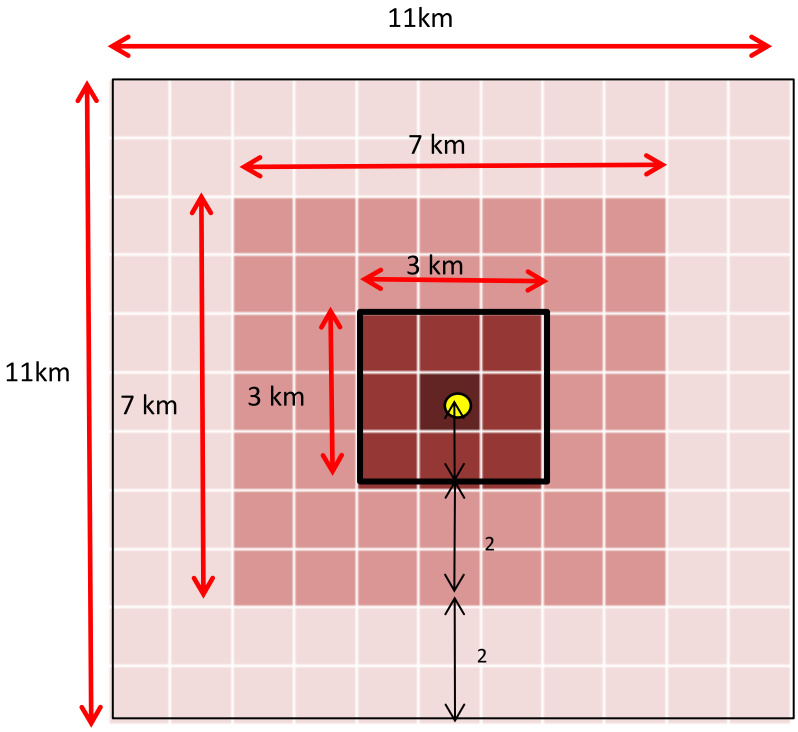


Figure 9. Representation of contingent resources and reserves areas based on anchor wells in pre-determined areas. Booked areas remain discrete until enough data is collected to confirm continuity of subsurface parameters within a given area. (Source: Santos and Moore)

Whereas exploration wells may have a density of the order of one well per 30 km^2 and production wells have a spacing of the order of one well per 1 km^2, appraisal wells are between these two extremes, with density dependent in part on the heterogeneity of the deposit and the opportunity to identify “sweet spots” (locations that are particularly favourable for CSG) from the exploration program. By way of example, AGL Ltd indicated that the existing Camden Gas Project has 134 producing wells in an area of 70 km^2. Moore (2012) discusses the spacing required for appraisal wells and also the type of wells needed to determine “bankable reserves”. Whilst stratigraphic drill holes can establish prospective resources (see Figure 9), wells specifically drilled to determine gas volume (and gas saturation) and permeability allow contingent resources to be determined. However, a pilot well is needed to demonstrate commercial flow and establish reserves. If an observation well is available to establish connectivity within the intervals, then the probable reserves can be further extended with a reasonable degree of confidence. The drilling of a pilot well requires not only compliance with the existing exploration licence but also new monitoring and reporting under the Aquifer Interference Policy and also water bore testing over an extended period.

Pilot well stage

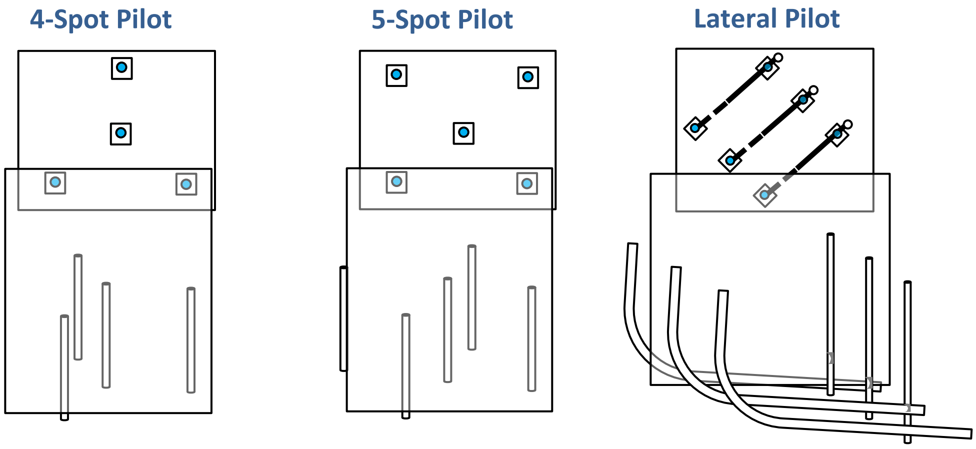


Figure 10. A CSG pilot consists of drilling, completing and producing a cluster of wells. A typical initial pilot design is a four spot or five spot vertical well, but in some circumstances, lateral wells coupled with vertical wells may be used to assess the variability of reservoir parameters , including simulating gas production in order to estimate project reserves. (Source: Santos)

The use of a pilot test is a particularly useful part of the assessment phase of the project. It involves the drilling of a cluster of 3-6 wells (Figure 10), depending on the anticipated production scheme. In some instances the wells are all vertical; in some cases a combination of vertical and lateral wells may be used. After the wells are drilled and cased (see later), the CSG is produced by decreasing the pressure in the coal (usually by dewatering), which desorbs the gas from the seam. The amount of gas that can be produced is then measured and used as the basis for estimated reserves if simulated economic gas rates can be achieved in the test. These are usually given as proven reserves close to the pilot well; proven and probable reserves, including those close to and further out from the well; and proven, probable and possible reserves close to, further out from and farthest from the well (Figure 9) – the further from the well, the less certain the reserves. Depending on the results of the pilot test, the configuration of wells may be changed to produce more optimum rates of CSG production. Usually one or more monitoring bores are also used to determine the impact of CSG production on the water table and to determine likely pressure communication between wells and beyond. This also provides a guide to heterogeneity of the coal and related geological formations. In addition, core samples are usually obtained as part of the pilot test, so that tests of gas desorption, coal rank etc. can be determined. Using the pilot test, a final scheme is developed for well spacing, whether or not fracking or horizontal wells will be necessary, that might improve the overall economics of the field. This in turn provides the basis for calculating the CSG reserves at 1P, 2P and 3P levels.

A.3 PRODUCTION

Having established that there are commercial (1P, 2P, 3P) reserves of CSG in the exploration area, the project is now ready to move to the production stage, but first it must obtain the necessary approvals, with the Minister for Resources & Energy responsible for issuing the PPL lease A development consent and Environmental Impact Statement are required and the project is required to meet monitoring and reporting regulations and, in some instances, the conditions of the Environment Protection and Biodiversity Act. Licences are also required for noise, waste water and air pollution. In other words, the approval process for moving into production is rigorous and can take some considerable time depending on the complexity of the proposal

An additional element of the production process is surface engineering such as the gas collection system, the major pipeline, processing and gas storage facilities. These topics are dealt with later. Here, only the subsurface components are considered.

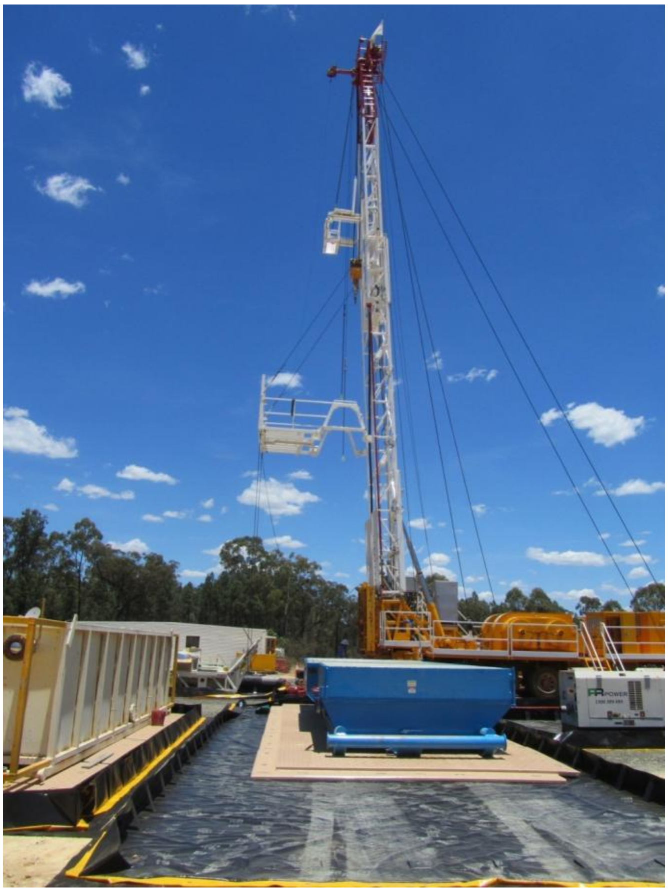


Figure 11. Typical drilling rig used for coal seam gas exploration or production wells. (Source: Santos)

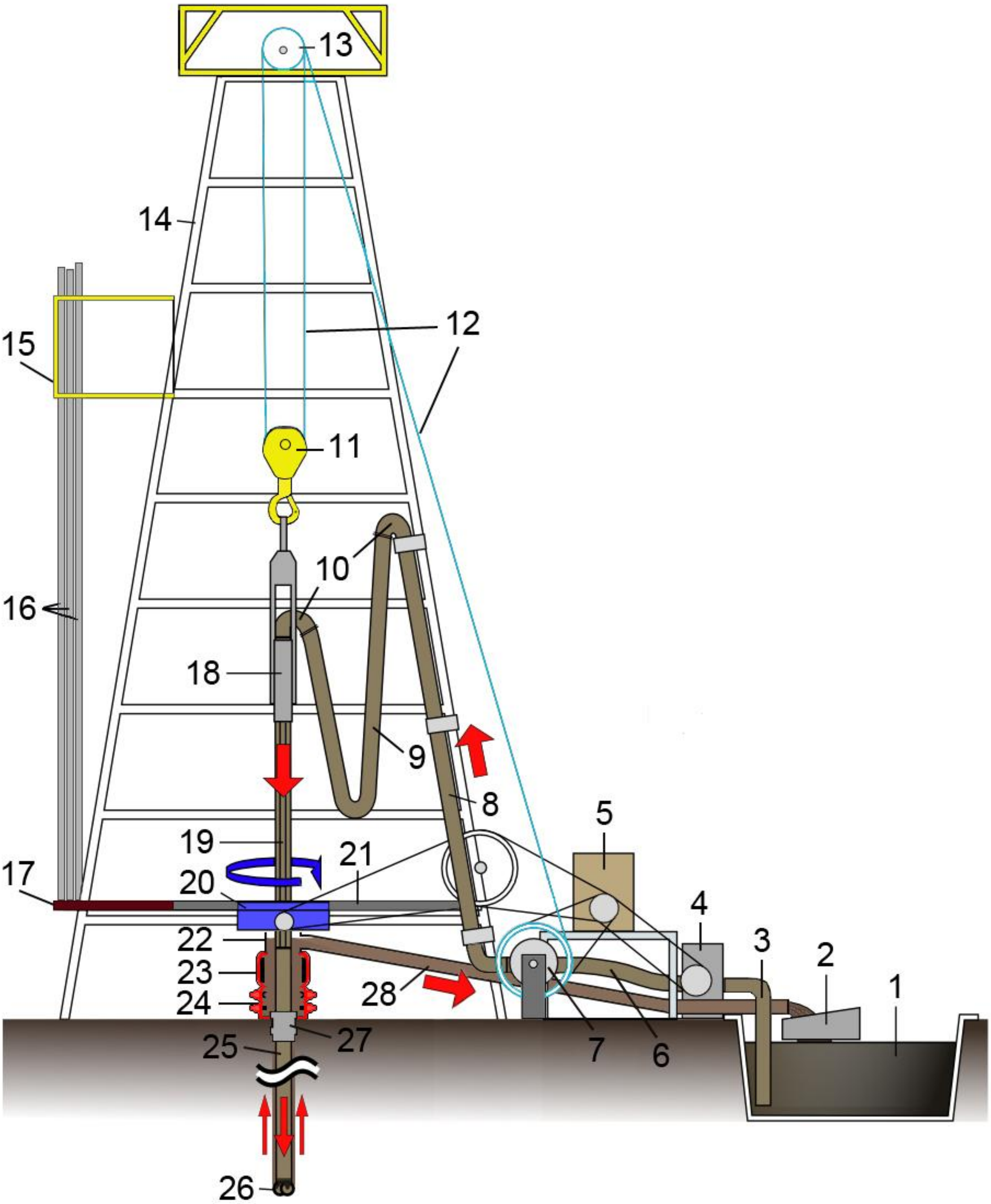


Figure 12. Schematic representation of a drilling rig (Source: SPE, 2007).

1. Mud tank, 2. Shale shakers, 3. Suction line (mud pump), 4. Mud pump, 5. Motor or power source, 6. Vibrating hose, 7. Draw-works (winch), 8. Standpipe, 9. Kelly hose, 10. Goose-neck, 11. Traveling block, 12. Drill line, 13. Crown block, 14. Derrick, 15. Monkey board, 16. Stand (of drill pipe), 17. Pipe rack (floor), 18. Swivel (On newer rigs this may be replaced by a top drive), 19. Kelly drive, 20. Rotary table, 21. Drill floor, 22. Bell nipple, 23. Blowout preventer (BOP)

Annular, 24. Blowout preventers (BOPs) pipe ram & shear ram, 25. Drill string, 26. Drill bit, 27. Casing head, 28. Flow line

Drilling a vertical well

Once all the approvals have been obtained, the project is free to enter a new drilling phase (Figures 11,12,13) which may consist of multiple vertical wells (with or without related horizontal wells), each approximating to the following schema:

- setting up the drilling rig and ancillary equipment and testing all equipment
- drilling the hole
- logging the hole (running electrical and other instruments in the well)
- running casing (steel pipe lining the well)
- cementing the casing (to hold it in position and to provide a barrier to fluids)
- logging the casing using a range of equipment that is lowered down the well
- removing the drilling rig and ancillary equipment
- perforating the casing (making holes in the casing to allow gas to enter the well) or using casing with pre-existing perforations
- hydraulic fracturing or stimulating the well (to allow to more easily flow to the well) if necessary
- installing surface production equipment
- putting the well in production
- monitoring well performance and integrity
- reclaiming the parts of the drilling location that are no longer needed and removing equipment to the next drill site (API 2009).

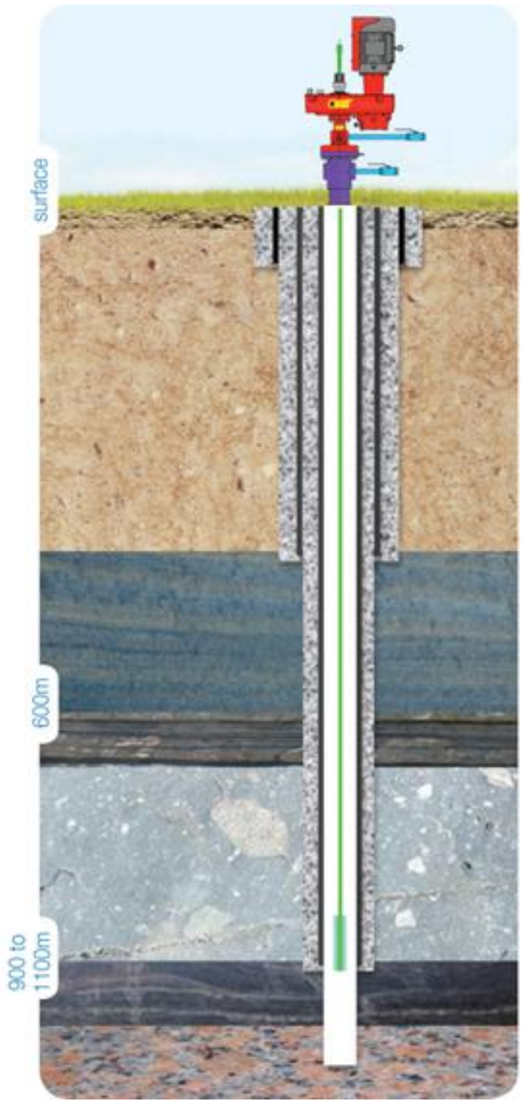


Figure 13. Typical design for a vertical well to confirm formation tops and to link in with horizontal wells where appropriate. (Source: Santos)

A well may require several of the cycles outlined above, depending on the depth of the well, as progressively deeper casing is installed, the diameter of the succeeding casing will be smaller than the diameter of the previously installed casing. The design of the well is specific to the local geological conditions.

The recent development of coiled drilling for vertical wells, using purpose built hybrid rigs has proved to be very successful in Queensland. It is being considered for parts of NSW, because of its significant noise reduction, the small size of its footprint and its greater efficiency in terms of drilling and mobilisation-demobilisation time (API, 2009).

Drilling a conventional vertical well utilizes what is called a "drill string". This consists of the drill bit which cuts through the rock, drill collars (heavy weight pipe to put weight on the bit), and the drill pipe.

The drill string is assembled, lowered into the drill hole from the mast (the crane-like top of the rig – see Figure 12) and then rotated by the use of a turntable (rotary table) or other types of motor drive. During the drilling, fluid (drilling mud) is circulated down the drill string and up the space between the drill string and the casing. This drilling mud is used in order to cool and lubricate the drilling bit, remove the rock cuttings (the bits of bedrock broken off during the drilling process), maintain pressure control of the well (to prevent gas escaping from the coal into the well), and stabilize the hole being drilled (to prevent it collapsing due to pressure or stress in the walls of the well). As the mud is pumped from a mud storage tank, down the rotating drill string, it exits the bit, lifting the cuttings to the surface, where the cuttings are separated and filtered out of the mud, which is returned to the storage tank. Some of the cuttings are saved for analysis; the rest are disposed of in a landfill if there is no contamination, or in an approved facility.

Drilling fluid is generally a mixture of water, clays, fluid loss control additives, density control additives, and viscosifiers, which together provide a fluid which has the right properties in terms of specific gravity, viscosity and geochemistry. The drilling fluid is a carefully monitored and controlled mixture designed to achieve best drilling results. The weight of the mud controls underground formation problems such as formation pressure or swelling clays. Fresh water is usually used in the shallower stages of a CSG well to minimise problems such as small leaks to shallow permeable formations. As the well is drilled deeper, weighting agents are added to control the increasing pressure. Air drilling can also be used and avoids the potential of chemical spills, although there can be temporary, non-toxic effects on freshwater aquifers such as taste due to aeration of the water.

Well logging

Once the well is drilled, and before the casing is installed and cementing begins, various instruments are often run on an electric cable into the drilled hole to locate and evaluate the various geological formations in the hole, in an operation known as well logging. This also allows casing strings to be correctly placed to properly achieve the isolation provided by the casings and cement. Common logging tools used for evaluation include:

- Gamma Ray—detects naturally-occurring gamma radiation which enables the geologist to interpret the rock types in the well
- Resistivity—measures the electrical resistance between probes on the logging tool in the wellbore. At least three resistivity logs are run, with the radius of investigation increasing with the distance between probes
- Density—measures the bulk density of the formation
- Caliper—measures the diameter of the wellbore. A 26 calliper log is used to calculate the hole size and volume of the wellbore, and therefore provides critical data that is used in the design of the cement job
- Image—involves taking a 360 degree photograph (or uses some other video imaging technology) so that the physical state of the well and also any evidence of fracturing or faulting, can be directly observed.

Well logging produces information, which is useful in optimizing the well design and drilling operation. It also determines the actual depth and thickness of the geological formations in the well, which in turn allows the installation of the casing in exactly the right place to achieve the well design objectives and to properly achieve the isolation benefits of the casing and cement and the protection of aquifers (API 2009).

Engineering the well

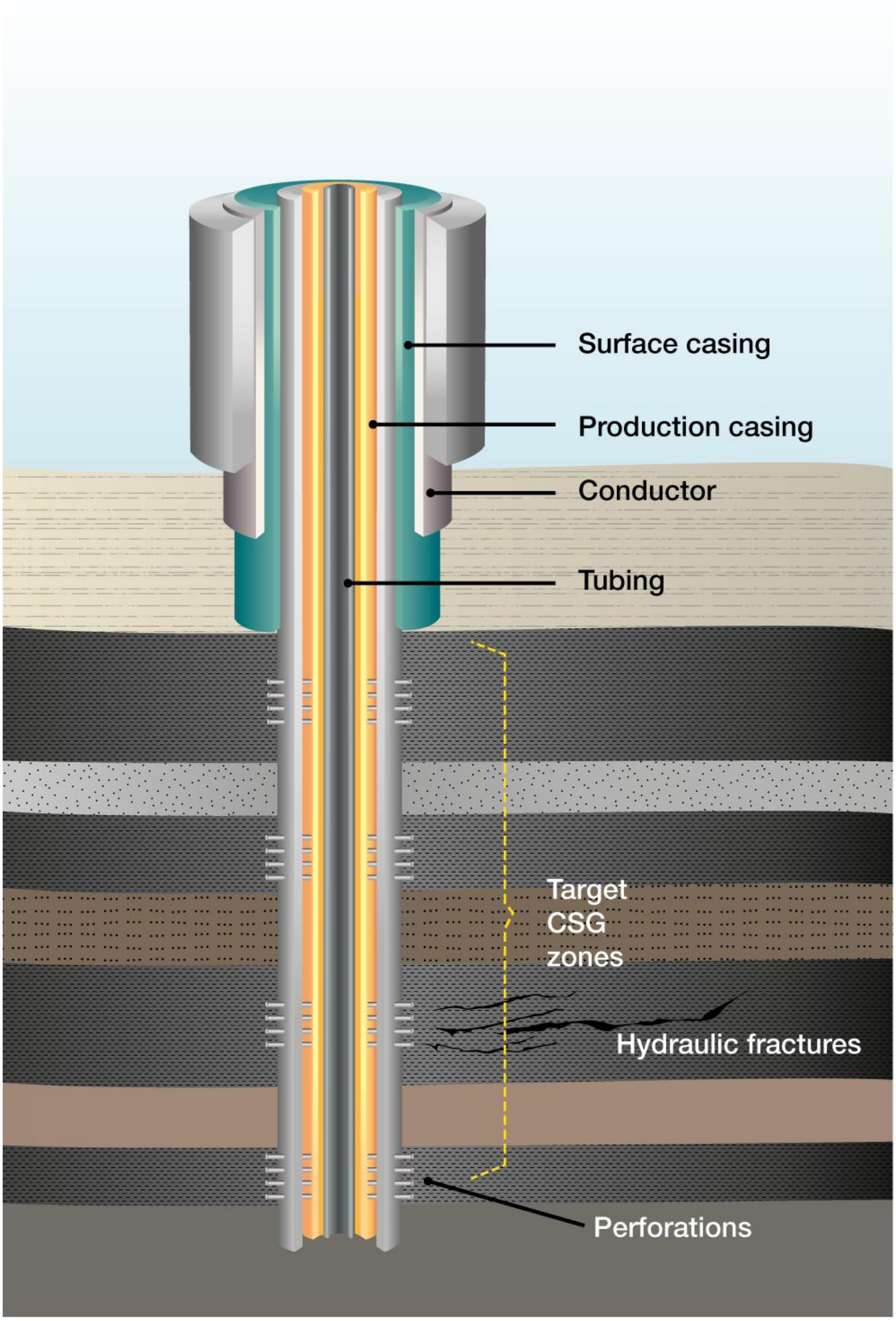


Figure 14. Schematic engineering detail of a typical vertical well, showing the casing sequence used to stabilise the well, seal off aquifers and provide the pathway for gas to be produced. Perforations are indicated for all seams; those with high permeability do not require fracking. For the purposes

of illustrating the technology, one seam is assumed to have low permeability and is therefore shown as hydraulically fracked.

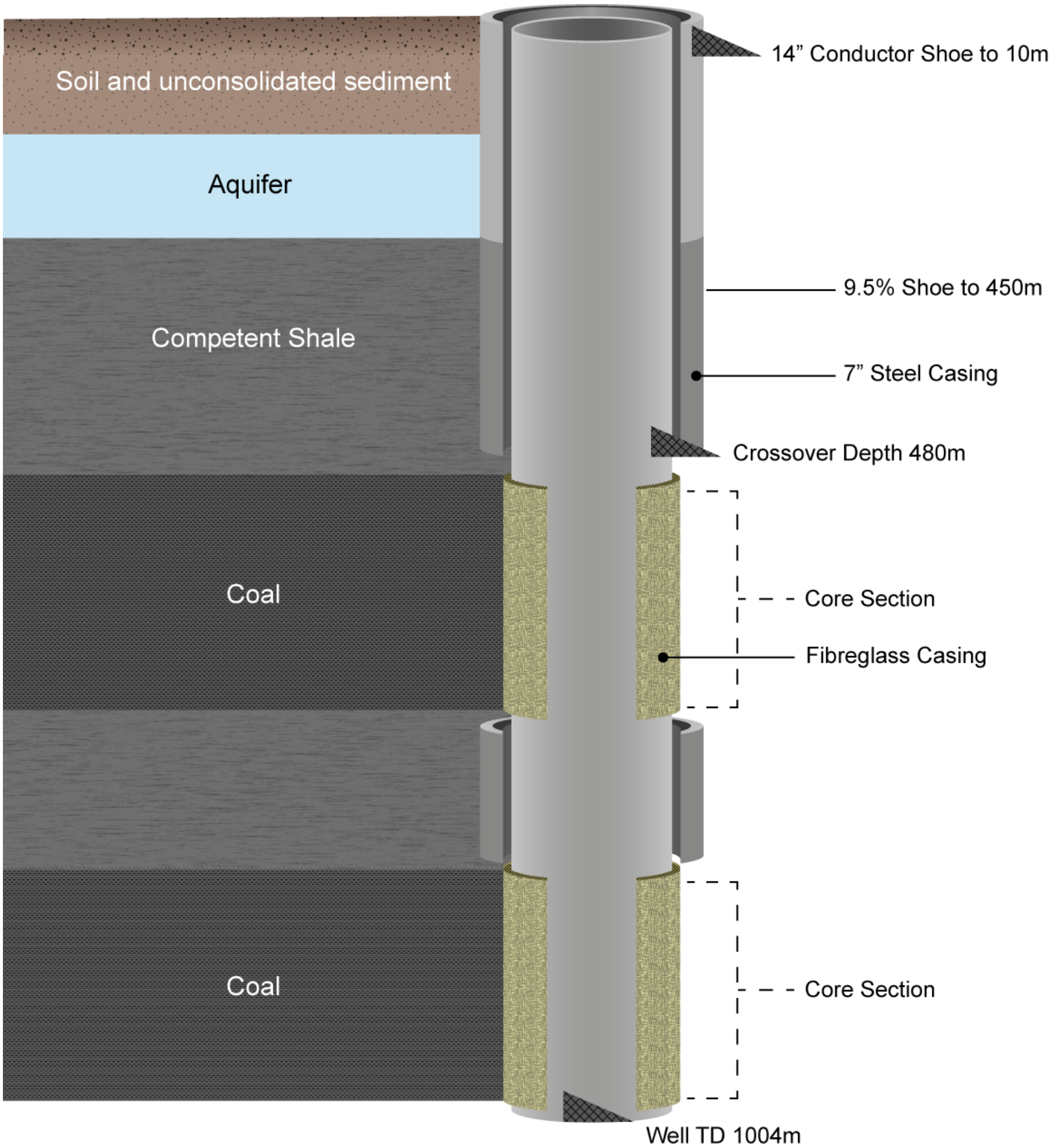


Figure 15. Schematic representation of how the geology influences the approach taken to casing the well. A 14” (approx. 35cm) conductor is set at about 10m depth to secure unconsolidated surficial sediments. A 9 5/8” (approx. 25cm) casing is set into competent shale below the aquifer and cemented to the surface. A 7” (approx. 18cm) casing is set above the targeted coal with fibreglass casing over the coal and cemented to the surface.

The term casing is used for the piping that is put into a well in order to stabilise it and prevent collapse and allow flow of CSG from the coal seam to the surface. At each stage, a (jointed) steel casing is inserted after drilling and cement is pushed down the casing’s inner diameter to its end, forcing the cement back up the annulus between the casing’s outer diameter and the drilled rocks. The cement is also forced between the sleeved casings themselves where they overlap, forming a multiple-layer impermeable seal to protect underground aquifers. Near-surface casing strings protect aquifers and extend below the deepest freshwater sands, preferably into sealing rock strata. The casing prevents unwanted flow of water or drilling fluid or gas, into or out of the well. Usually the casing is steel, with the composition depending on the nature of the gas being produced, although it can also be plastic. First a large diameter surface casing is set (Figure 14). Once the casing or sections of the casing (depending on the needs of the well and the presence or absence of aquifers) are positioned in the well, they are cemented to ensure the casing is fixed in position and also to protect aquifers from any leakage from the well (Figure 15). The well is then deepened and the production casing lowered into the well and cemented to ensure no leakage of produced gas. Finally the production tubing is lowered into the cased well. The design and selection of the casing is of utmost importance and is quite specific to the needs of the well. As pointed out in the API (2009) guidelines:

> The casing must be able to withstand the various compressive, tensional, and bending forces that are exerted while running in the hole, as well as the collapse and burst pressures that it might be subjected to during different phases of the well's life. For example, during cementing operations, the casing must withstand the hydrostatic forces exerted by the cement column; after cementation, the casing must withstand the collapsing pressures of certain subsurface formations. These subsurface pressures exist regardless of the presence of hydrocarbons. Design of the steel casing strings is a key part of the well design and a key factor in well success, including assurance of zonal isolation and wellbore integrity. It is the prime responsibility of operating companies, drilling contractors, and their drilling engineers and supervisors to design and review the design of the casing, as well as the plan to run and install the casing during well construction. Casing design and running are carefully executed technical processes.

Further,

> stringent analysis and execution of well construction and integrity is of key importance in eliminating potential leak paths. For 75 years the industry has successfully drilled and produced wells using modern drilling techniques. Continuous improvements in technology and practices have allowed these wells to maintain their integrity and provide the required isolation. The ultimate goal of the well design is to ensure the environmentally sound, safe production of hydrocarbons by containing them inside the well, protecting groundwater resources, isolating the productive formations from other formations, and by proper execution of hydraulic fractures and other stimulation operations. The well design and construction must ensure no leaks occur through or between any casing strings. The fluids produced from the well (oil, water, and gas) must travel directly from the producing zone to the surface inside the well conduit.
>
> The design basis for well construction emphasizes barrier performance and zonal isolation using the fundamentals of wellbore preparation, mud removal, casing running, and cement placement to provide barriers that prevent fluid migration. The selection of the materials for cementing and casing are important, but are secondary to the process of cement placement. The performance of the barrier system to protect groundwater and isolate the hydrocarbon bearing zones is of utmost importance. All well designs and well plans include contingency planning. Although seldom needed, these contingency plans are in place to mitigate and eliminate the risk failure due to unplanned events, and most importantly, to ensure the protection of people and the environment (API, 2009).

Horizontal Wells

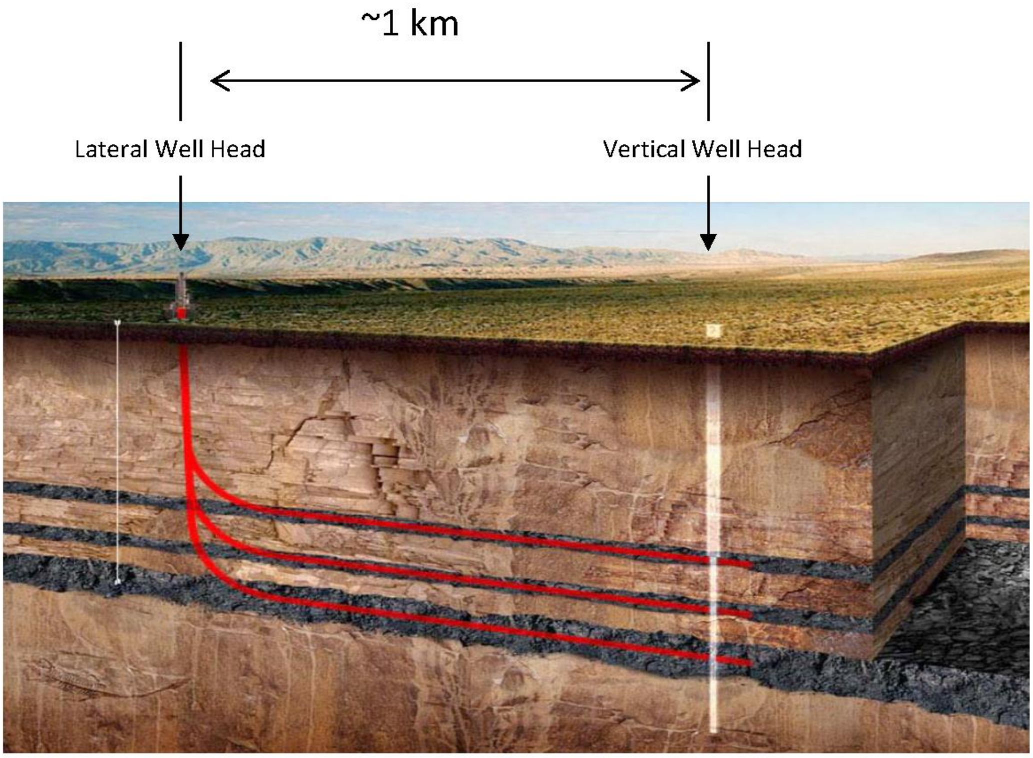


Figure 16. The use of vertical and lateral drilling to access multiple coal seams as a concept for optimum gas recovery in the Narrabri area. (Source: Santos)

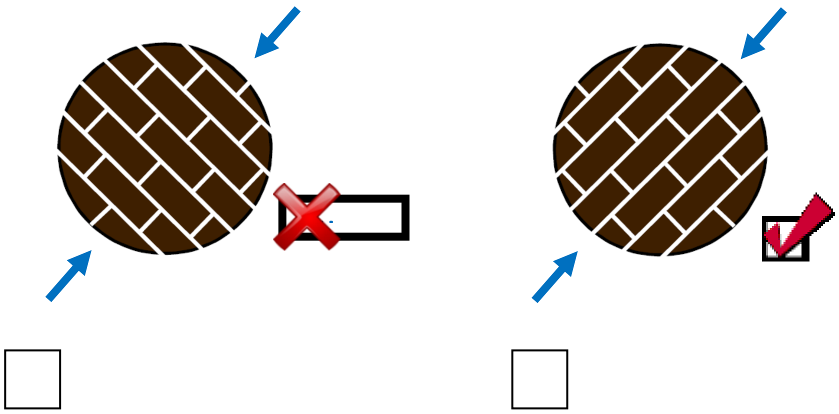


Figure 17. Geomechanical information provides a picture of subsurface stress magnitudes and orientation, which is then used to plan the optimum direction of a lateral well to access maximum permeability. For example, in the Bibblewindi area of the Gunnedah Basin, lateral wells would be used rather than fracking to maximise gas production. (Source: Santos)

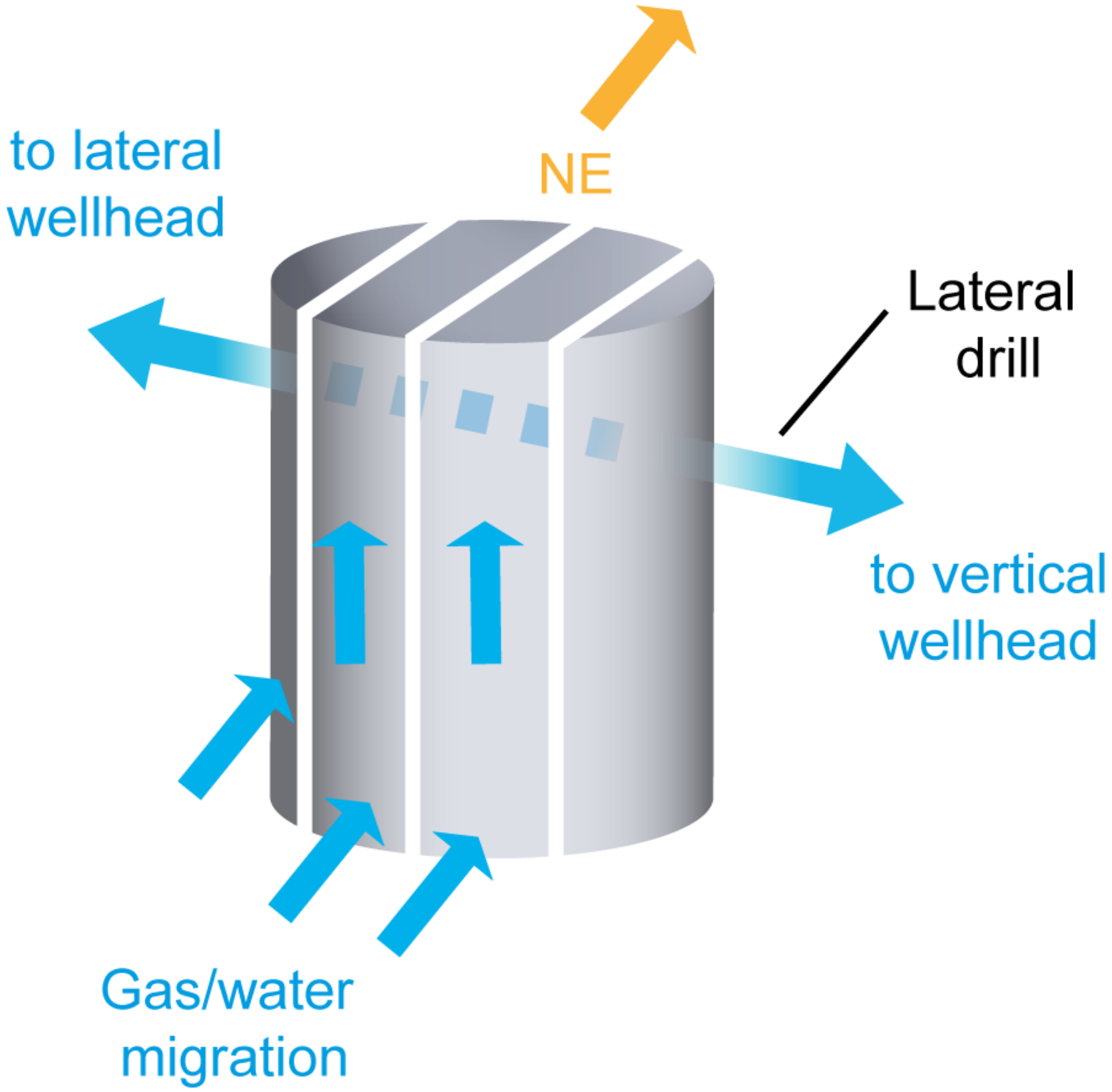


Figure 18. Detailed schematic to show how a lateral well is oriented at right angles to the northeast trending master cleat direction. (White lines represent the master—or dominant—cleat direction; the prominent blue arrows represent the orientation of the horizontal well ; the smaller blue arrows represent the direction of migration of the water and gas.

In some instances, where the rate of gas production is sub optimal from a vertical well, it may be necessary to drill one or more lateral horizontal wells from the vertical well, which intersect the length of the coal seam for up to 800m or more from the well (Figure 16). There are various ways that this can be done, but most commonly the aim is to intersect the coal seam perpendicular to the coal seam fracture orientation, which allows the natural permeability to be used to most effectively drain gas from the seam (Figures 17, 18).

Where the coal has low permeability, then a horizontal well, or wells, may enhance the rate of production of gas by contacting a much larger volume of gas-bearing coal (Figure 19). This may be done by first drilling a conventional vertical well, lowering a steerable downhill motor mechanism to the bottom of the well and using that to drill a horizontal well or multiple horizontal wells, in the preferred

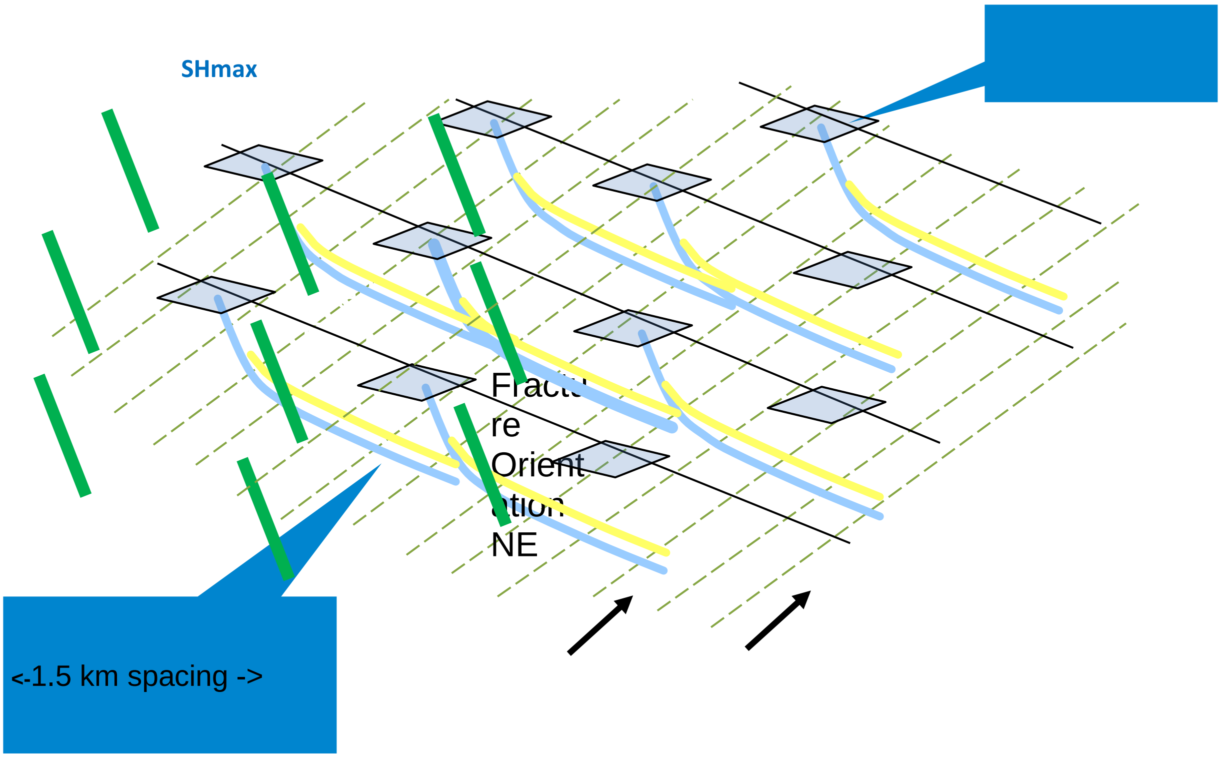


Figure 19. Subsurface development concept for the Narrabri area based on multi well pads, with stacked lateral wells perpendicular to the coal seam fracture orientation and vertical well intercepts at 1-1.5km spacing. (Source: Santos)

orientation. Alternatively a deviated well is drilled, which commences as a vertical well but then at the optimum depth will be steered out of the vertical into a progressively less inclined well, with the aim of drilling horizontally for up to several hundred meters distance within the coal seam. A GPS system and the Earth's magnetic field, is used to monitor and steer the drill bit in the right direction. Increasingly, several deviated wells /horizontal wells are drilled from the same well pad, so that a web of horizontal wells radiates out from the site. This has a number of advantages including lower cost, faster drilling times and smaller surface footprint.

Santos have found in the Narrabri area that the existence of a very prominent "master cleat" in the Bohena Coal means that lateral wells perpendicular to this master cleat are very effective as a way of accessing the gas and obviates the need for fracking the vertical well. If there is more than one seam then a second and a third lateral well may be drilled. Whilst it varies from place to place, in the Gunnedah Basin for example, a new vertical well may be drilled from the same well pad to intersect the lateral well and more efficiently drain the seam (Figure 19).

A variation on the use of lateral horizontal wells is provided by radial drilling from the vertical well into the coal, using a modified coiled tubing technology to drill multiple small diameter lateral wells up to 100m from the vertical (like a hub and spoke configuration) using high pressure jets.

Depending on the geomechanical properties of the coal, the lateral wells are often not cased. However they can become less efficient over time due to build-up of sand-size particles of coal within the lateral well and need to be cleaned perhaps once a year to maintain optimum gas flow.

Fracking a well (see also p 66)

Hydraulic fracturing, or fracking, has been used by the oil and gas industry since 1947 and the Society of Petroleum Engineers (SPE) estimate that 2.5 million hydraulic fractures have been undertaken worldwide, with over 1 million in the United States (King, 2010d; King, 2012). In Australia, deep hydraulic fracturing has been previously carried out in 70 wells in the Cooper Basin. In the CSG industry, shallow hydraulic fracturing (less than 1000m depth) has been undertaken in hundreds of wells in eastern Australia.

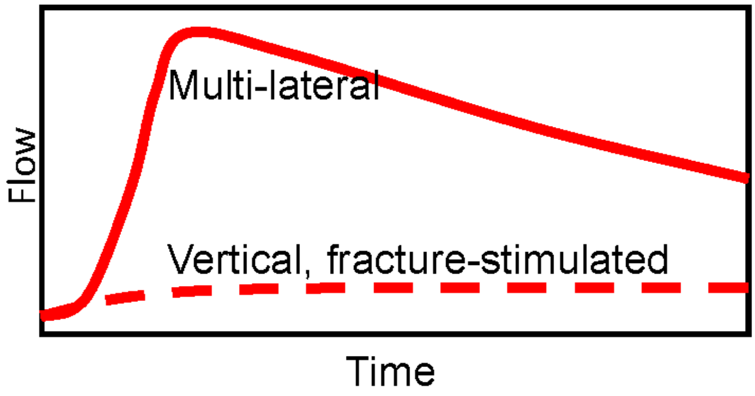


Figure 20. Schematic illustration of the difference between the relatively modest gas flow from a single vertical fracked well compared to the much higher flow rate from horizontal multilateral wells.

In some instances, the dewatering and depressuring of the coal seam is insufficient to stimulate gas flow in quantities that make the well a commercial success. In this case it may be decided to carry out fracture or stimulation, usually in a vertical well to allow gas to move more readily through and from the coal seam (Figure 20). Not all wells require fracking; if there is adequate natural permeability then fracking is not necessary. From the point of view of a CSG company, fracking is expensive and can be complex. Therefore if it can be avoided, then it will be. For example in the Gunnedah Basin, the major cleat pattern is optimally oriented for gas production and whilst it is necessary to drill a horizontal well or wells to intersect that preferential fracture pattern, it is not necessary to enhance the fracture pattern by fracking. In most if not all cases, fracking is not used to enhance production in horizontal wells in coal seams, because the well is uncased and the coal would not be suitable for fracking.

In some circumstances, fracking is undertaken in vertical wells through the perforations in the steel and cement casing, to establish or enhance the connectivity between the producing coal seam and the well. The deciding factor in whether or not to frack a well is the natural rate of gas production without fracking, the natural fracture pattern and the stress field in the vicinity of the wells. Not all coals are suitable for fracking because of the stress field at the site. A schematic representation of a fracked coal seam is shown in (Figure 14).

Fractures form in the direction perpendicular to the least stress. At shallow depths, the Earth's overburden pressure is the least principal stress and horizontal fractures will occur usually parallel to the bedding plane. As depth increases, overburden stress in the vertical direction increases and the overburden stress (stress in the vertical direction) becomes the greatest stress and fractures tend to be vertical. However the stress direction is also a result of tectonic forces within the plate and in the case of the Australian plate, compressive forces tend to dominate which can have a major impact on the manner in which fractures propagate. It is also strongly influenced by the nature of the rocks above and below the coal, which tend to act as confining layers, which can serve to limit the vertical extent of any induced fracturing either because of the strength of the overlying or underlying layer or because of their elasticity, which serves to contain the pressure of the injected fluids within the target formation.

In order to undertake hydraulic fracturing, the fracking fluid is pumped at high pressure through the production casing that has been cemented and is able to withstand the hydraulic pressures. A so called "frack string" may be used to isolate the high pressure fracking fluid from the production casing. Because of the high pressures involved in the fracking operations, the operator has to take great care to ensure that there are no leaks that could result in loss of fluid or present a health and safety issue. The process of fracking may be carried out in stages that are varied depending on the downhole conditions. The fracture is initiated in the targeted coal. In some cases, very small amounts of sand may be added in short bursts in order to abrade or fully open the perforations and enter the coal to form fractures. As part of the next stage, varying concentrations of proppant, (sand that has been sieved to a particular size), are added to the fracking fluid. Other specialized proppants include sintered bauxite, which has an extremely high crushing strength, and ceramic proppant, which is an intermediate strength proppant. The purpose of the proppant, which is chemically quite inert, is literally to prop open the fractures that have been propagated within the coal. Excess sand is then flushed out of the well to be either recycled or disposed-of at an approved site.

Whilst fracking generally uses a liquid, it is possible to undertake fracking using air or nitrogen or carbon dioxide. This obviously reduces the possibility of fracking fluid contaminating groundwater or surface water, but it is a noisy process which can adversely impact on a nearby community and to date has not been widely used in Australia.

The hydraulic fracturing process, which is usually carried out by a specialised service company, requires a range of specialist equipment and materials including fluid storage tanks, proppant transport equipment, blending equipment, pumping equipment, and all ancillary equipment such as hoses, piping, valves, and manifolds. An essential element of the fracking process is careful surface and subsurface monitoring, using a range of instrumentation that enables the operator to ensure the fracking is proceeding satisfactorily, or if it is not, to remediate or terminate the operation if necessary. Data being acquired could include fluid rate from the storage tanks, slurry rate being delivered to the high-pressure pumps, wellhead treatment pressure, density of the slurry, sand concentration, chemical compositional changes and so on. A key element to watch for is that there is no induced fracturing occurring beyond the target interval that could, for instance, result in contamination of an aquifer. It is also important to ensure that there is little likelihood of an induced seismic event occurring. Some of these potential impacts are discussed later.

Producing CSG from a well

Once the well has been successfully drilled, cased, perforated and, if required, fracked, it is necessary to bring it into production. In order to produce CSG from a well it is necessary to decrease the pressure so that desorption of the coal takes place from the coal surface (Figure 21). In addition there will be diffusion and release of the methane through the coal matrix and micropores. Further, there is then movement of gas through the cleats and fractures within the coal. Dewatering is usually required to depressurise the seam and enable the gas to flow out of the coal and into the production well. The ratio of water to gas produced from a well may vary from more than x20 in a wet coal to x1 or less in a dry coal. In most CSG wells, water production is a major component of gas production and requires careful monitoring to ensure that the chance of adverse impacts on aquifers is minimised. However this cannot be done solely by monitoring the pressure or the water level in a single well, for the effects of water production can extend far beyond a single well, producing a more areally extensive draw down (lowering) of the water table. It is with this potential impact in mind that the NSW Aquifer Interference Policy was drafted.

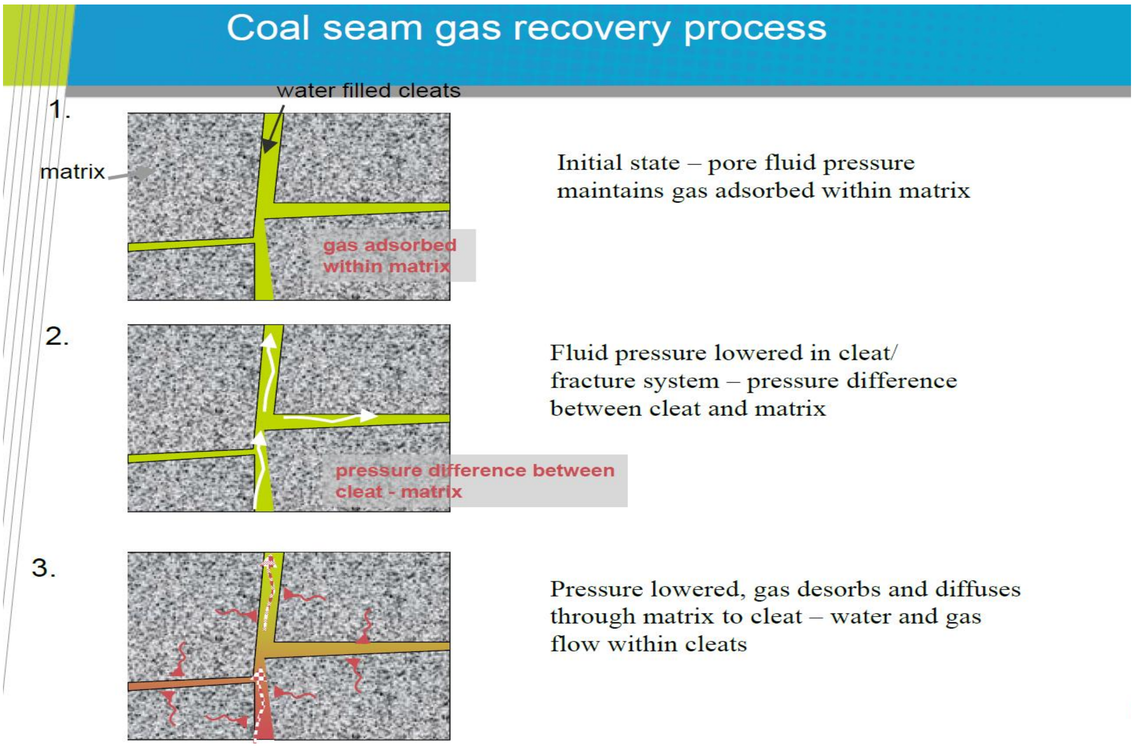


Figure 21. The coal seam gas recovery process as the pressure in the seam is progressively lowered. (Source: CSIRO)

In order to allow the gas to flow from the coal into the well, it is necessary either to use a preperforated casing in the well or to perforate the casing in the well. By far the most common perforation method utilizes jet perforating guns loaded with specialized shaped explosive charges that are lowered down the well to the depth at which perforation is to occur. The shaped charge is detonated and a jet of hot, high-pressure gas vaporizes the steel pipe and cement and for several centimetres into the coal seam. The result is a series of small diameter isolated tubes or tunnels that connect the well inside the production casing to the gas-bearing coal formation. The producing zone is isolated from adjacent intervals (including aquifers) by the cement, which is set above and below the production zone. The perforated vertical well may also be fracked, to increase gas production.

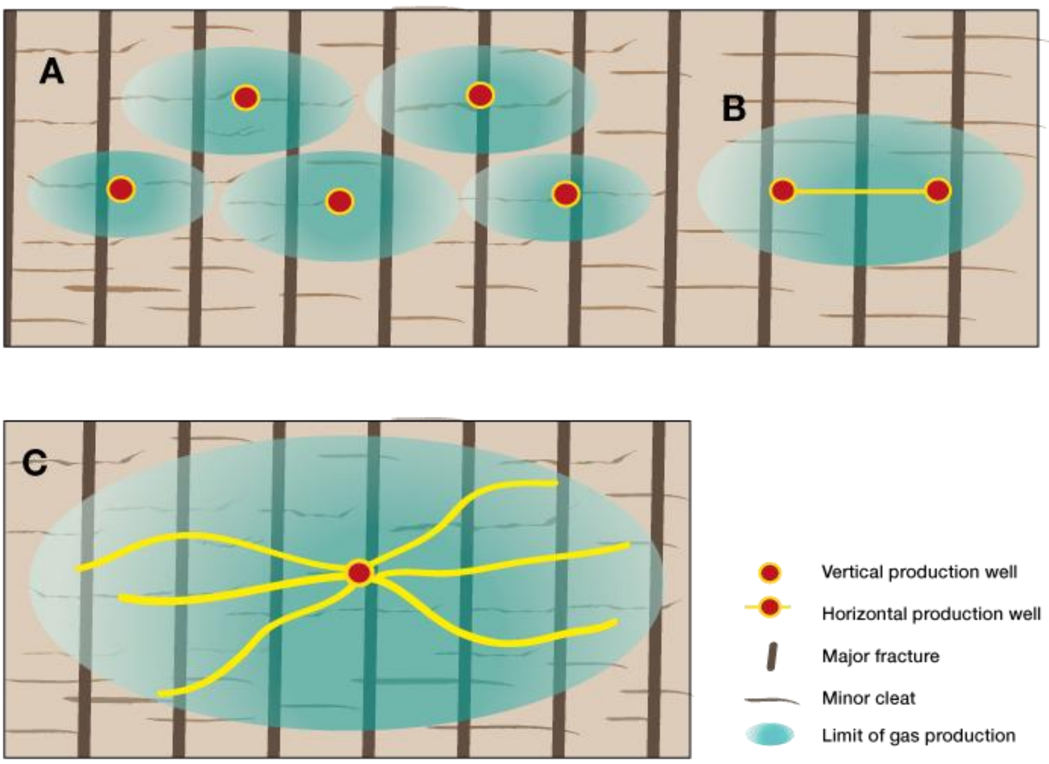


Figure 22. Schematic representation of various configurations showing in plan, the outline of the area of coal drained during CSG production wells. A) Multiple vertical conventional wells each draining a relatively small area/volume of coal. B) A single vertical plus horizontal well draining an intermediate area/ volume of coal. C) A series of multilateral wells drilled from a single well pad draining a large area/ volume of coal.

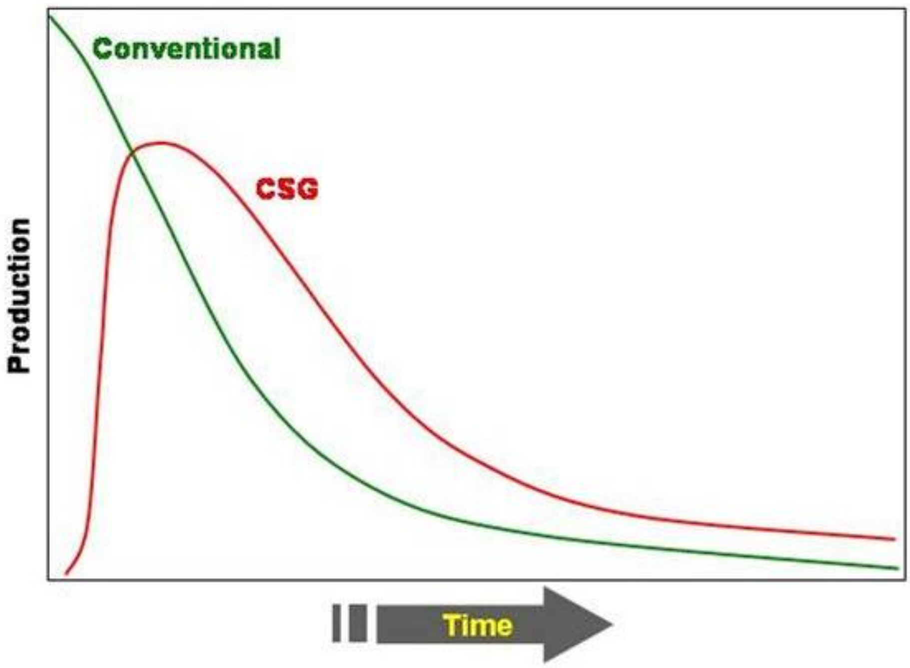


Figure 23. Comparison of the gas production profile over time for a conventional gas well and that for a CSG well.

It is important to once again stress that each CSG field and each well is different in terms of how it is brought into production. Nonetheless, the key elements remain the same, namely of ensuring that a sufficient volume of the coal can be accessed (and drained) by drilling vertical and in some cases also horizontal wells, that it is sufficiently permeable either naturally or through hydraulic fracturing of a vertical well, and that the methane can be released from the coal by producing water and decreasing the pressure.

Unlike a conventional gas field which may need just one or two wells, because of the nature of CSG deposits, and the limited volume of coal (and gas) that can be accessed from a single vertical CSG well, it is necessary to drill many production wells at quite close spacings, of 1-2 km or less. Although as pointed out earlier, increasingly, multiple wells are being drilled from the same pad and long-reach deviated or horizontal wells are being used to maximize the production zone within individual coal seams (Figure 22). Nonetheless there can, in places, be a high concentration of production wells, particularly in some of the fields that were brought into early production like those in Queensland.

In a conventional gas well, maximum production of gas occurs at the start and declines from thereon. The production curve of a CSG well is quite different in that there is a steep initial increase to a peak following the dewatering operation (Figure 23). As the gas flow continues, the amount of water produced tends to decrease. However the flow of the groundwater from a CSG well is extremely variable, as is also the quality of the water produced. The rate of gas production decline can also be highly variable from well to well, which can cause difficulties in reserve estimation. Over the life of the well, which is probably on the order of 20-30 years, the total amount of water produced can be highly variable ranging from megalitres to gigalitres per annum, which in some circumstances, though certainly not all, can have a significant impact on some aquifers if there is any connectivity with the coal. It can also mean that a large amount of water has to be disposed of, either by reinjection into the subsurface or by surface discharge or surface use (in agriculture for example); or in the case of saline water, it may be left in surface ponds to evaporate, though this can lead to other problems and is generally strictly regulated. Therefore the handling of water in an effective and responsible manner is a very important and integral part of the gas production process.

In the case of the South Sydney Basin, the coals are relatively dry and are fully saturated with methane. Consequently, a CSG production well typically produces no more than a few thousand litres of water over 1-2 weeks. The coals of the Gunnedah Basin are somewhat wetter and therefore have a much higher rate of water production associated with gas production, although the total volume will be less than that abstracted by existing users. The issue of groundwater is considered later in more detail.

A.4 SUSPENSION, CLOSURE, ABANDONMENT

Suspension

On occasions, production of CSG from a well may be suspended for days or weeks. Reasons for the suspension include the need to remediate the well because there has been a failure in the steel casing or in the cement casing in a vertical well. In the case of a horizontal well, the well may have become clogged by sand size particles of coal which can gradually accumulate in the well during gas production and result in a significant decrease in gas production. This is a not uncommon reason for a suspension and horizontal wells often need a “cleaning” operation every 12 months or so to remove the sand. This requires that a workover rig be brought to the site for a day or two. A workover rig is usually a smaller and less sophisticated rig than the one used to drill the original well. However it is able to undertake tasks such as positioning a patch on the casing or remediating the cement if a leak has developed, or cleaning out the well. In order to undertake these tasks safely it will be equipped with a blowout preventer, which ensures that the gas does not constitute a hazard, and is required to undertake all tasks in a manner that meets all industry standards and government HSE requirements.

Closure

Closure of the well may be carried out if the rate of gas production has dropped to a level where it is no longer economic to produce from the well. Less commonly, closure may occur because a well has developed a leak or has malfunctioned in some other way that requires that the well first be remediated where necessary or is plugged prior to it being abandoned.

Abandonment

Abandonment of a well has to follow clear guidelines and is carefully regulated under the NSW Code of Practice for Coal Seam Gas (September 2012), to ensure that there is no possibility of a long term hazard or a pollution event arising from the well. First the production tubing and any other related equipment is pulled out of the well, then steps must be taken to maintain isolation of potable or useable aquifers from each other and from the CSG zone (Figure 24). Then in order to minimise risk to future coal mining operations, there may be a need to mill out some of the vertical or deviated steel casing. If there is any horizontal fibreglass casing, the regulator may agree to this being left in the well as it would be unlikely to interfere with mining operations.

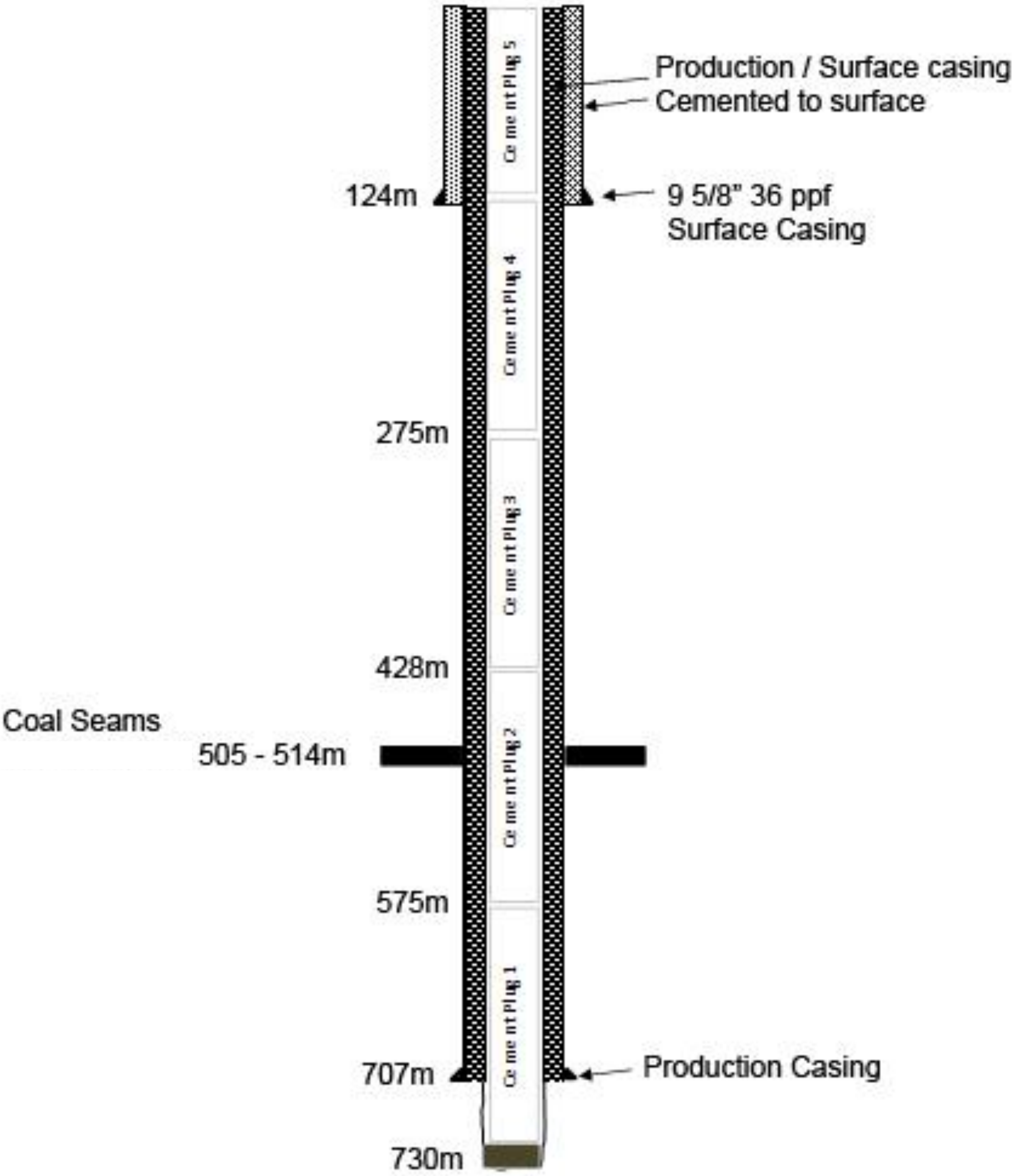


Figure 24. A proposed well abandonment scheme (Wilga Park No 2), showing the isolation of the aquifers from each other and from the gas-bearing coals. The well is cemented to the surface with a series of cement plugs. (Source: Santos)

Finally the drill hole is cemented from the bottom to the top of the well. In order to ensure that the cement sets satisfactorily, this is done in maximum lengths of 200m with the first cement plug set inside the casing and tested to ensure it is able to withstand pressures in excess of 500 psi above the formation pressure. The well is also usually geophysically logged to confirm that the steel casing is in a satisfactory state, prior to setting casing to the top of the well (API, 2009).

As part of the abandonment process, the operator is required to rehabilitate the area around the well. The gathering lines are usually left in position as they are buried to a depth of around a meter and therefore it is less disruptive to leave them buried than to retrieve them. The well is capped and may be protected by a wire enclosure. A condition of abandonment might be to be that monitoring of one or more aquifers be undertaken. This can be done using a monitoring borehole near the production well, equipped with a series of piezometers to measure the pressure in the aquifer or aquifers.

A.5 TRANSPORT PROCESSING AND STORAGE OF GAS

Transport

Transporting and processing gas is a surface or near surface process which requires that all operations and processes are undertaken with full regard for health, safety and the environment. Whilst no operation of any sort can be totally risk-free, they are performed to best practice, with risk as low as reasonably practical (ALARP). All gas companies are expected to have incident management and safety audit systems in place for recording all hazards and incidents, not just to minimise them but also to learn from them if they do occur. Safety in terms of the general public is handled by excluding the public from installations through fencing and monitoring, or in the case of pipelines by burying them at a depth below agricultural activities.

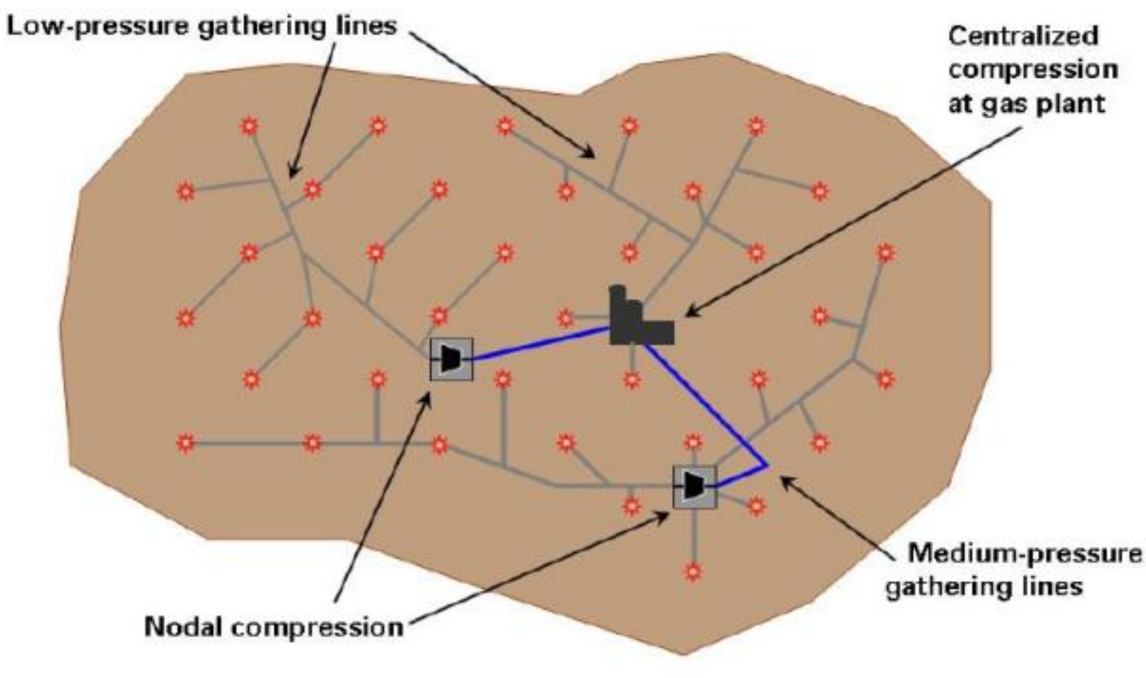


Figure 25. Typical scheme for CSG gas gathering and compression. (Source: BP)

Transport of the gas from the well head is through polyvinyl gathering lines, which vary in diameter with the volume of gas being carried (Figure 25). The gathering line is buried to a depth of approximately one metre. Because the produced gas is at a low pressure, the transport in the gathering lines is a relatively low risk operation. Nonetheless it is carefully monitored at the well head and at the processing point. Any pressure drop between these points is immediately registered and triggers a series of procedures to identify the leak or the malfunction and take remedial action. There is also an automatic cut-off at the well head should there be a rapid increase or decrease in pressure. There is also an automatic cut-off if the level of radiant heat increases due to a fire, although the possibility of a well head being damaged by a bush fire is minimised by having a zone of low grass and no trees or bushes around it. The operating company will also have its own protocols in place on days of high bush fire danger and all well heads have video monitoring that transmits back to the central monitoring station, which is manned 24/7.

Monitoring for gas leaks is a feature of CSG transport and processing. Although there is obviously a risk of fire and explosion if there is a gas build-up from a pipeline leak or a processing plant, danger posed by gases that can occur along with the methane, is generally low because there is little or no hydrogen sulphide (which is a highly toxic gas) in CSG in NSW. The dangers posed by leaking methane beyond the processing plant are guarded against by adding an odouriser to the methane, such as a mercaptan, which can be detected at very low concentrations. Overall there are no additional dangers posed by CSG, compared with conventional gas production; indeed it could be argued that CSG in the gathering lines is at a significantly lower pressure than conventional gas and therefore poses less of a hazard.

Figure 26. The AGL Rosalind Park Gas Plant at Camden (photo by author).

Processing

The processing plant for CSG is relatively simple, both because of the comparatively small volume of gas processed and the low concentration of contaminants. The plant is also small with a modest visual impact. For example the Rosalind Park Gas Plant near Camden covers an area of an estimated 5-10 hectares and the installations have an average height of 3-4 m (Figure 26). The main plant comprises gas-fuelled engines, a reciprocating compressor with four-stage compression and inter-stage cooling, and treatment facilities for dehydration using triethylene glycol. In addition, a gas odourant injection system and an oily water scrubbing plant are needed. A horizontal flare system is in place as a safety measure in case over pressuring of the gas occurs. The plant is continuously monitored for gas, smoke, fire and water removal. Monitoring for noise and ambient light suppression is in place. The Rosalind Park Plant has a visual screen of trees up to the boundary of the plant as a condition of planning approval.

The gas is then delivered to the market through a high pressure steel pipeline which is required to conform to the Australian Pipeline Industry Association (APIA) Code of practice. The pipeline is continuously monitored and there are shutdown protocols in place. Gas detection surveys are undertaken and the status of the pipeline is reviewed through regular “pigging” programs of subsurface inspection. A pipeline inspection gauge or "PIG" is a tool that is sent down a pipeline and propelled by the pressure of the product flow in the pipeline itself. The PIG is used for internal cleaning of pipelines and inspection of the condition of pipeline walls (also known as an Inline Inspection (ILI) tool).

Storage

Storage of gas occurs *de facto* through the volume of gas in the pipeline, though the volume is small. The main storage facility attached to the operations of AGL is through a mini LNG plant near Newcastle which can be activated to respond to increased demand or reduced gas supply. Deep geological storage (in deep aquifers) is a widely used gas storage option, with many hundreds of such sites operating around the world. In eastern Australia, there is only one operational geological gas storage site, the Iona Storage Facility in the Otway Basin of Victoria. In the Sydney Basin, the opportunities for this sort of storage option are limited by the generally low permeabilities in the Basin. A comprehensive program of exploration for permeable sandstones in the Sydney, Gloucester or Gunnedah basins might reveal some storage options (Ozimic, 1979).

B. FACTORS THAT CONTRIBUTE TO SITE SELECTION FOR CSG ACTIVITIES

A number of factors contribute to the choice of sites for CSG activities, including geology, likely environmental impacts, the potential environmental and social impact of drilling and construction activities; operations and issues of waste management.

Geology

Arguably, geology is the single most important factor in selection of a site, to the extent that the rocks have to be the "right" rocks. In other words they have to contain sufficient gas in a sufficiently thick coal seam that can be produced at a sufficient rate to make a project commercially viable. It is of course possible to influence the extent that the CSG can be produced by drilling a horizontal well or fracking a vertical well, provided the mechanical properties of the strata are suitable.

However there are also a number of other factors that need to be taken into account to ensure that a location is suitable for development. Many of these are summarised in the "Exploration" section of this report (see earlier). A geological parameter that can influence location is the composition of the gas which can vary from location to location. For example, in some areas, the CSG is so high in carbon dioxide that it is not worth producing the gas. A site may be preferred because it is geologically simple; extensive folding or faulting may add considerably to the cost of development or limit the volume of gas-bearing coal that can be easily accessed. A site with complex hydrogeology is likely to be avoided because of the difficulties in aquifer management that might be encountered during the dewatering process. A major fault zone will almost always be avoided because of the difficulties in predicting the subsurface conditions of the site and the prospect of this leading to increased risk and uncertainty. There is also the possibility that hydraulic fracturing or disposal of waste water at such a site could lead to induced seismicity. All of these factors are taken into account in what is often referred to as site characterisation and one of the tasks undertaken by all companies is to ensure that they have a sufficient understanding, so that they can predict with a high degree of confidence how the site will "behave" once CSG production commences. The earlier discussion pointed to the importance of downhole logging in understanding the subsurface and this technology is usually a critical component on the site characterisation process.

Environmental and cultural impacts

Environmental considerations can be very important indeed to the precise location of a drill site. Whilst the geology dictates the general location from where the CSG can be produced, it is possible to drill a well in such a way so that it deviates from the vertical, making it possible to avoid drilling on a site which is environmentally or culturally sensitive or one which will impact unduly on a farm or a community. The advent of horizontal drilling is particularly useful in this regard. There is a limit to the extent that a well can be deviated or to the reach of a horizontal well, but the surface location of the drill rig and the subsequent well head can normally be moved by up to several hundred metres to meet environmental or cultural needs. In addition, issues such as noise, particularly at the drilling stage, can be mitigated by measures such as sound screens. The Government decision to establish buffer zones between CSG activities and residences has been taken to minimise the social impact of the activities.

Engineering and construction

Impacts that affect siting can include increased road traffic during and after the drilling phase. Water disposal is a potentially significant issue in some areas. For example in the Gunnedah Basin, water disposal influences not only the route for water pipelines but also the location of holding ponds and water disposal facilities. The route of a gathering line to take the methane from the well head to the major pipeline or the processing plant can usually be varied to handle local needs. The location of the processing plant can similarly vary, but is the subject of planning, environmental and other regulations which serve to dictate where the plant will be sited. Obviously a number of these issues come into focus where CSG production occurs in areas of intensive agriculture and within or close to urban areas or rural 'lifestyle' areas (Figure 6), although in the Camden area CSG production, agriculture and the urban fringe have co-existed for a number of years. In the Gunnedah Basin, PPLs and PALs for CSG are located several kilometres from Narrabri (Figure 27).

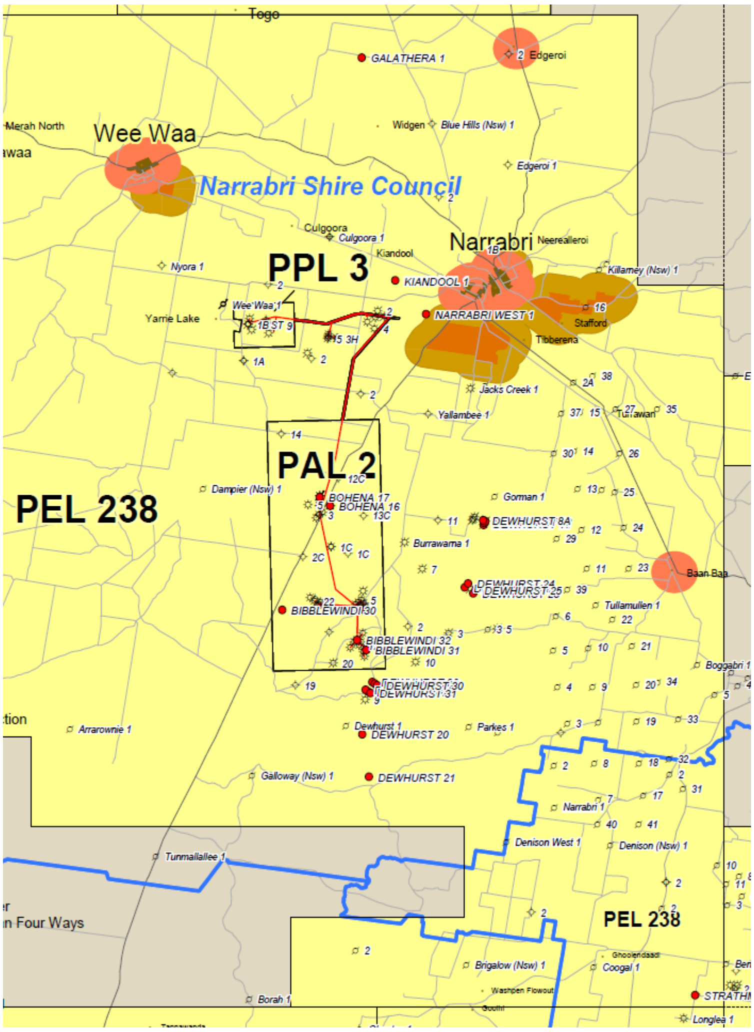


Figure 27. The proximity of CSG operations to towns and residential developments is dependent on the geology and the production scheme for the gas field. In some instances (for example in the Sydney Basin) issues arise from the spread of residential development into an area of pre-existing CSG activity. Proximity of a residence to a CSG well is limited under current regulations in NSW. In the case of the Gunnedah Basin, CSG activities are located some distance from towns. (Source: Santos)

C. HOW DIFFERENT GEOLOGICAL CONDITIONS IMPACT ON CSG DEVELOPMENTS

Wet and dry coals

There are marked differences in NSW between wet coals such as those of the Gunnedah Basin, where gas production and dewatering can involve extraction of very large amounts of groundwater, and dry coals such as those of the Sydney Basin, where the amount of produced water is quite modest. However it is important in comparing basins to also consider the maturity of the field, in that produced water progressively decreases with time. By way of example, AGL reports that in the Camden field, some 80 CSG –producing wells in this operationally mature basin produce less than 5 ML of water a year. In the Hunter Valley, two exploration wells produce 1ML of water a year. In the Gloucester Basin, 15 exploration wells produce approximately 4 ML a year but the expectation of AGL is that the 110 production wells needed would produce approximately 730ML of water a year. Santos estimates that in the Gunnedah Basin, the water treatment plant would need to handle 5-7ML a day or approximately 1800-2500 ML a year. Therefore the effective handling of produced water has to be a major component of a project that is producing from wet coals.

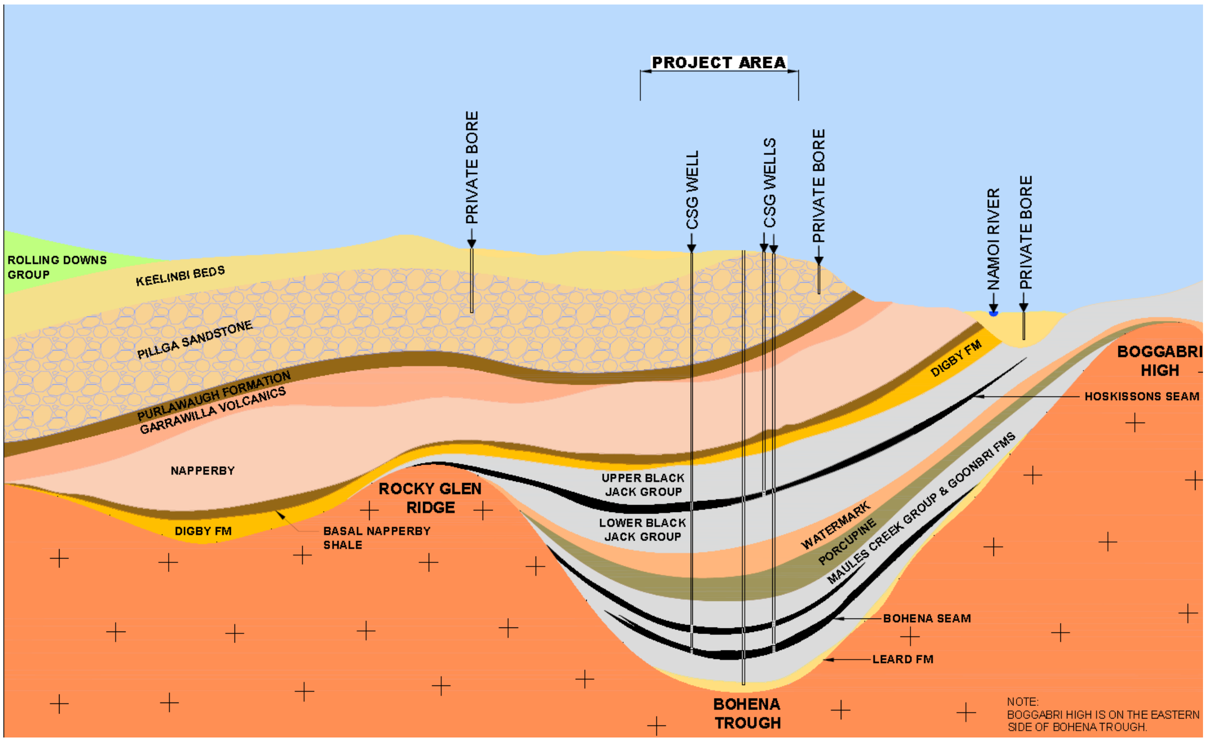


Figure 28. Schematic regional geological section across part of the Gunnedah Basin, showing several hundred meters of separation between the CSG producing zones, and the major aquifers, such as the Pilliga sandstone or some of the shallow sediments in the vicinity of the Namoi River.

(Source: Santos)

Why are some coals wet and others not? It is a function of the basin geometry and groundwater recharge coupled with the permeability of the coal. As pointed out earlier, the deeper the coal, the lower the permeability and therefore the lower the water content of the coal. However it is important to point out that the amount of groundwater produced as a by-product of CSG production is not just a function of the “wetness” of the coal, but is also dependent on the extent to which there is connectivity between the coal and the sandstone aquifers that may overlie or underlie the coal. In areas where there are hundreds of meters of separation and one or more thick aquitard between the CSG zone and the main aquifers (Figure 28), the chance of water from CSG production impacting on the shallow aquifers is likely to be low over the life of the project. Conversely, in parts of Queensland where the CSG-bearing coals are shallow and the aquifers relatively deep, there is a high likelihood that CSG production will adversely impact on some aquifers. In the South Sydney Basin, very little water is produced and there appears to be little or no impact on aquifers.

Stress regimes

The stress regime within a coal sequence influences the production of CSG in several ways. It can for example have a significant influence of the way a well has to be engineered. If there is over pressuring (the pressure in the geological formation is greater than the hydrostatic pressure), then heavier drilling muds have to be used, which can then result in formation damage and a decrease in permeability. It can also result in instability within the well.

The stress field can also play a major role in enhancing the productivity of gas from a coal. For example, if there is a major and consistent open fracture pattern oblique to the cleat direction, then a greatly enhanced rate of CSG production can be obtained by drilling a horizontal well at right angles to the fractures (Figures 17,18).

The stress pattern can also have a major influence on the effectiveness of fracking and the type of fracking undertaken. Rarely if ever is fracking undertaken in horizontal wells in coals, but if it were, the aim would be to generate vertical fractures if the overall stress field were extensional. In fact the stress field in Australia is generally compressive and fracture patterns resulting from fracking are more likely to be horizontal. Therefore in Australia, the fracking undertaken for CSG is in vertical wells. A further influence that the stress field can have is on the potential to generate induced seismic events either due to fracking or, more likely, due to the subsurface disposal of fluids, in that if a fault is critically stressed, then injection of fluids into the fault plane can induce some movement on a critically stressed fault. It is therefore necessary to understand the stress field to minimise the chance of induced seismicity occurring, though it is important to recognise that overall, the likelihood of significant induced seismicity is low.

Rock type

The lithology of the coal is a major influence on the potential for the occurrence of abundant CSG and the prospect of commercial flows of CSG being generated. As pointed out earlier, the higher the rank of the coal (its level of maturity, measured by determining the vitrinite component and its reflectance), the higher the likely gas content of the coal. The rank of the coal also influences the composition of the gas, with higher rank coals tending to contain a greater proportion of carbon dioxide in the CSG, although the composition can also vary with other factors such as the presence of late stage volcanic activity or the presence or absence of bacterial activity. Permeability is also related to coal rank, in that the higher the coal rank is, the lower the permeability.

The lithology of rocks in juxtaposition to the coal seam can also have an influence on the production of CSG. In some circumstances where coal is overlain by reservoir rocks, such as a porous and permeable sandstone, methane can leak from the coal into the sandstone and be trapped (if there is suitable closed structure, such as an anticline) resulting in a conventional gas prospect. Where there is a permeable sandstone which is an aquifer, in juxtaposition to the coal, then dewatering of the coal to induce CSG production can also draw down the water table i.e. reduce the pressure, in the aquifer. The presence of such a juxtaposed aquifer can also constitute a potential pathway for contamination (for instance from drilling or fracking fluids) from the producing horizon into the aquifer.

Depth

There is a general trend of permeability decreasing markedly with depth, with Moore (2012) reporting that coal at 100m depth may have permeability of hundreds of millidarcies, whereas that same coal at a depth of 1000m may have a permeability as low as 1-2 millidarcies. This obviously has a major impact on production of CSG, and may increase the likelihood that fracking may have to be used to obtain an adequate rate of CSG production from the well. Depth also has an impact on drilling costs which in turn affects the economics of the project. As pointed out previously, deep coals are more likely to be dry coals, which means that less dewatering is required, although the overall rate of CSG production may be less. In addition, the deeper the coal the less the likelihood of biogenic enrichment of methane, with methanogenesis generally ceasing at a depth of approximately 600m, depending on the groundwater flow within the basin.

Differences between NSW and Queensland coals

There are a number of important differences between NSW and Queensland coals, the manner in which CSG is produced and the impact of that production. That difference has absolutely nothing to do with the presence of a state boundary and everything to do with the geology of the coal bearing basins. The main basins for east Australian CSG production are those of the Bowen–Gunnedah-Sydney Basin System, which is Permian-Triassic in age and the Surat Basin System which is Jurassic-Cretaceous in age. The discussion is perhaps better related to these systems than to the state boundary *per se*. Essentially all of the CSG production in NSW is from rocks of Permian age, whereas production in Queensland is from both basin systems, i.e. Permian and Jurassic-Cretaceous. This, coupled with the related rocks and aquifers and their juxtaposition, has a major influence on many aspects of CSG production in the two states, particularly the very large amounts of water produced by CSG operations in Queensland compared to the quite small amounts produced by NSW CSG operations in the south Sydney Basin. Water produced from the Gunnedah Basin Project would be greater than the Camden area but Santos anticipates that it would still be much less than the Queensland CSG operations.

<u>Bowen-Gunnedah-Sydney System</u>

These basins, as shown in Figure 3, extend from southern NSW and the Sydney Basin through the Gunnedah Basin and to the Bowen Basin in north central Queensland. The coals are generally bituminous and high rank throughout, formed under deltaic conditions in a foreland basin setting. These conditions produced the great lateral continuity and thickness of the coals, ranging from 3-35m in thickness. In areas of Queensland such as the Fairview area, high permeabilities have resulted in high rates of production of CSG. There are well defined CSG “fairways” in the Queensland Bowen Basin extending from the Fairview area into Scotia, Mooranbah and Moura and it is from these areas that a major part of the CSG production is, or will be delivered to LNG projects at Gladstone. The production of CSG from the Bowen Basin is complicated by the fact that much of the basin is overlain by the Surat Basin, which not only contains CSG-producing coals but also major aquifers. Most of the Queensland production is from relatively shallow coals and because of the presence of shallow overlying aquifers there is more connectivity between the coals and the aquifers than there is in NSW, which results in far more produced water of varying quality in the Queensland Bowen Basin

In the Sydney and Gunnedah Basins of NSW, the CSG is generally produced from greater depths; the coals have lower permeabilities and are much “drier” than those of Queensland. Therefore produced water is less of a challenge though CSG volumes may be less in NSW than in Queensland. The Gunnedah Basin is perhaps intermediate in terms of volumes of produced water, between the Sydney Basin to the south and the Bowen Basin to the north and it has a well-developed Permian fairway in the Bando-Narrabri area. Overall, the Queensland Permian coals have a higher vitrinite content (55%) than the Permian coals of NSW (40%) which is reflected in the CSG and the fact that the Queensland coals tend to be under-saturated with respect to methane, whereas the NSW coals are saturated (meaning that less dewatering is required to initiate degassing).

Surat Basin System

The fluvio-lacustrine Jurassic Walloon coals of the intracratonic Surat Basin System are thinner (0.5-5m) and more discontinuous than the Permian coals, although their total thickness can be up to 50m with an average of 30m. This means that CSG production is from more intervals and there is greater connectivity of coals and sandstone aquifers than in the Permian rocks and as a consequence, far more produced water. The groundwater picture in Queensland is further complicated by many of the Jurassic CSG areas that are also recharge areas for the Great Artesian Basin. The fact that much of Queensland CSG production is quite shallow (as little as 200m depth in places) means that there can be significant draw down of the shallow water table.

Surat Basin sediments extend into northern NSW but to date there has been no significant CSG production from them, because the coals are thinner and of poorer quality. This also applies to the similar age sediments which occur in the Clarence–Moreton Basin of northern NSW, where exploration is underway, but to date little production. The northern part of the Gunnedah Basin is overlain by sediments of the Surat Basin such as the Pilliga Sandstone, which is an important aquifer system, but as the CSG production from the Bohena Trough is from 600-1200m depth, there is little or no connectivity with the shallow aquifers (Figure 27).

In summary then, the differences between CSG projects in NSW and those in Queensland, are that those in NSW are from older Permian coals that are lower in permeability, methane–saturated, generally drier with much less produced water, and, therefore will likely have much less impact on shallow aquifers. Conversely, NSW coals of the Sydney Basin overall are rather less prolific producers of CSG than those of Queensland, but some of the coal seams of the Gunnedah Basin may approach Queensland coals in terms of potential CSG productivity.

D. TECHNOLOGY AND IMPACT ON ECONOMICS & DYNAMICS OF CSG EXTRACTION

Over the past 10-20 years, a range of technologies, many of them developed for conventional oil and gas exploration and production, have been introduced to the CSG industry, making the industry not only technically viable but also more financially viable. A comprehensive discussion of all these technologies would double the length of this report and therefore the discussion is restricted to some of the key technologies, but in summary the new techniques have been targeted at improved exploration, faster drilling times, improved production, enhanced monitoring capability and decreased footprint.

Exploration techniques

Perhaps the single most significant technology advance in the past two decades has been the improvements to 2D and especially to 3D seismic techniques, which allow an accurate picture of the subsurface geology to be developed. This, along with our improved knowledge of depositional systems, coupled with geophysical methods such as magnetic and gravity surveys, allow an accurate analogue model to be developed. When coupled with new digital reservoir modelling techniques and improved software, it is possible to develop a comprehensive dynamic geological model which predicts with some accuracy, the behaviour of a coal seam and associated sediments, the likely recovery of CSG and the potential impact of CSG production on groundwater. The modelling is further enhanced by the inclusion of geomechanical and geochemical data as well as permeability data (where available), which together make it possible to predict the stress fields and the gas volume—important parameters when planning the pilot program and the likely production regime—as well as recovery factors and well trajectories (Figure 19).

Modelling is a rapidly developing area of technology, largely because it is used so widely by the conventional oil and gas exploration industry. The techniques deployed are effective, but there is no doubt that in the coming years the techniques will improve further and will provide a much higher resolution of the subsurface geology than is possible now. One of the single most important, yet most difficult, parameters to obtain with any confidence is the in situ permeability of the coal. It would be useful to be able to obtain this information at an early stage in the project. The options that exist at the present time for determining permeability include in situ measurements through a modular dynamics tester tool available through Schlumberger or Halliburton, or through a magnetic resonance tool. The accuracy of these methodologies for coal is uncertain, which means that expensive injectivity tests, or more likely pilot tests, are usually necessary as well.

Drilling techniques

There have been a number of improvements to drilling techniques in recent years. Smaller more mobile rigs have brought down drilling costs, reduced drilling times and minimised the footprint of a single rig. The advent of multi-well drilling from a single pad has similarly brought down drilling costs, drilling times and the footprint. Coupled with the capability to drill deviated wells, the technology has provided far greater flexibility to the explorer and producer in terms of well positioning. The accuracy with which wells can now be steered is a very important component of the success of the long reach wells. One of the greatest technology breakthroughs has been the ability to drill horizontal wells for up to a kilometre or more, thereby providing access to a far greater volume of coal than is possible from a single vertical well. The use of horizontal wells designed to intersect paired vertical wells within the coal seam, with the assistance of a rotating magnet rotating service to facilitate well intersection, is an example of a more advanced configuration, of the type proposed for the Gunnedah Basin which will serve to decrease costs and maximise gas recovery (Figure 19).

The composition of drilling muds has advanced in recent years using more effective polymers to control viscosity and also more benign additives such as fertilizer-based fluids, thereby providing a simpler and better option for recycling (reducing the waste stream considerably), with 90-95% recovery of drilling muds now possible, or if necessary disposal of drilling muds on an approved landfill site. It is worth noting that some of these same developments are being applied to fracking fluids (API 2009).

Horizontal drilling has had a major impact on the economics of CSG projects and will continue to do so, with the main developments in the future being ever longer horizontal reach and steering with ever more precision. In 1986, a total of 41 horizontal wells were drilled worldwide by the oil and gas industry; there are now thousands drilled worldwide each year, many of those by the CSG industry. Recent developments are enabling companies to now integrate horizontal drilling operations with resistivity tools and high resolution imaging devices, to create very accurate structural models of the downhole conditions. The use of radial drilling techniques for horizontal drilling has promise, but at the present time the principal shortcoming of the method is the need to engineer a large cavity at the bottom of the well from which the radial device can be deployed.

Engineering the production well

The improvements in recent years to the suite of geophysical downhole logging techniques available for accurately measuring the properties of rocks intersected in a well, has resulted in far greater precision and confidence in designing and engineering a production well. Setting and cementing the casing is now done with a high degree of confidence. At the same time if a well unexpectedly fails for some reason, the range of remediation options that can be put quickly in place has increased. Costs have also been brought down by design repeatability. Perforation of the casing is now performed more effectively thereby further enhancing gas production (API, 2009).

The ability to monitor the downhole performance of a well in real time helps to identify any potential problems and enhance performance. The capability to do this is now available for example through the installation of fibre optic cables in the well casing. The technique is used in a variety of research applications, and increasingly is being deployed in monitoring wells (Figure 29), though not necessarily routinely in CSG production wells.

Hydraulic fracturing

After drilling a well and establishing the casing, the drill rig is removed. To connect the interior of the final casing to the coal, a perforating gun configured with electrically-triggered shaped charges is lowered by wireline into the vertical well. The explosive charges generate a jet that cuts through the casing and its cement seal at this point into the reservoir (several 10s of cm penetration) to create holes through the casing and into the rock formation, or if the casing has already been perforated then the fracking fluid will "jet" from the perforations into the coal (Figure 14).

Hydraulic fracturing does not have the significance for CSG production that it has for shale gas production (see later). In that many CSG wells do not require fracking, it is nonetheless an important component of the technology mix for CSG. The topic of fracking has been dealt with in some detail by King (2012), the US National Academy of Sciences (2012) and the Royal Society (2012) and most recently by Cook et al (2013). It is also considered again later in this report, but in summary, depending on the permeability, fracking for CSG is carried out in many but not all vertical wells. It is seldom if ever used in horizontal CSG wells. A significant proportion of the vertical production wells in the Camden area for example, do need to be fracked because of the nature of the geology, whereas this is not the case in the Narrabri area where horizontal wells are more widely used. A number of techniques have been developed to monitor the effectiveness and extent of fracturing and these are discussed later.

Water management

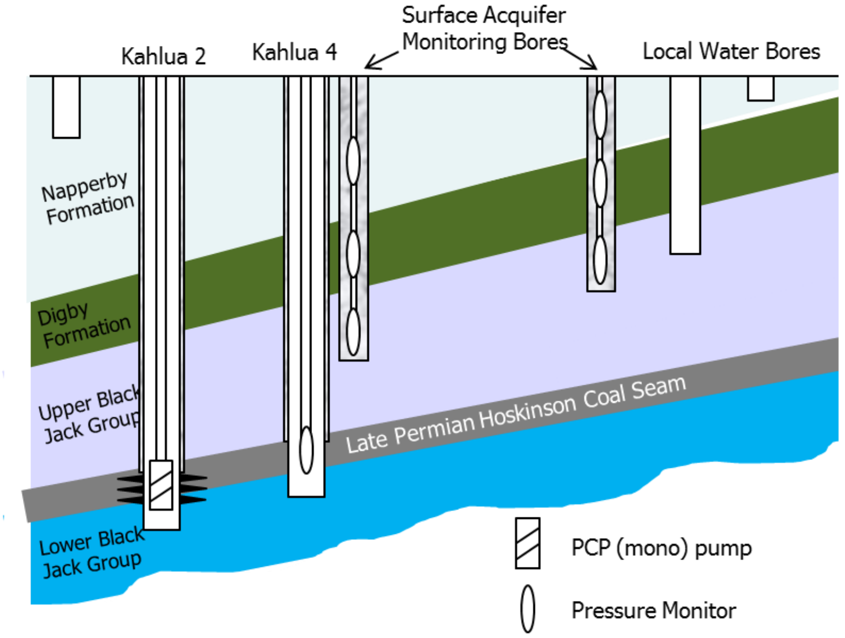


Figure 29. Groundwater monitoring scheme proposed for the Gunnedah Basin. (Source: Santos)

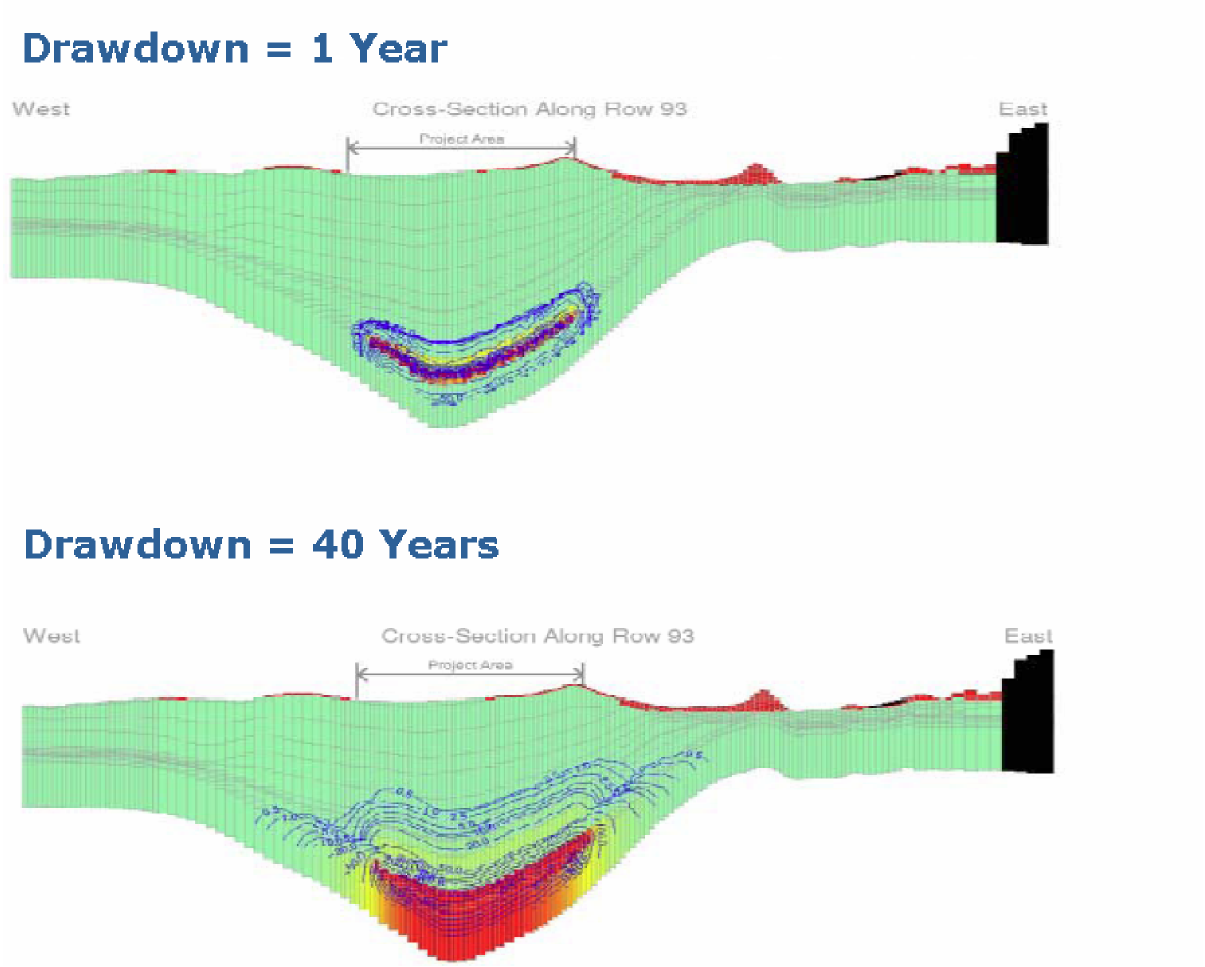


Figure 30. Groundwater modelling is an important tool in ensuring that impact of gas production and associated water does not impact on shallow aquifers. In this example from the Bohena Trough, the model suggests that there is no drawdown of the shallow water table in response to deep production of CSG after 40 years. (Source: Santos)

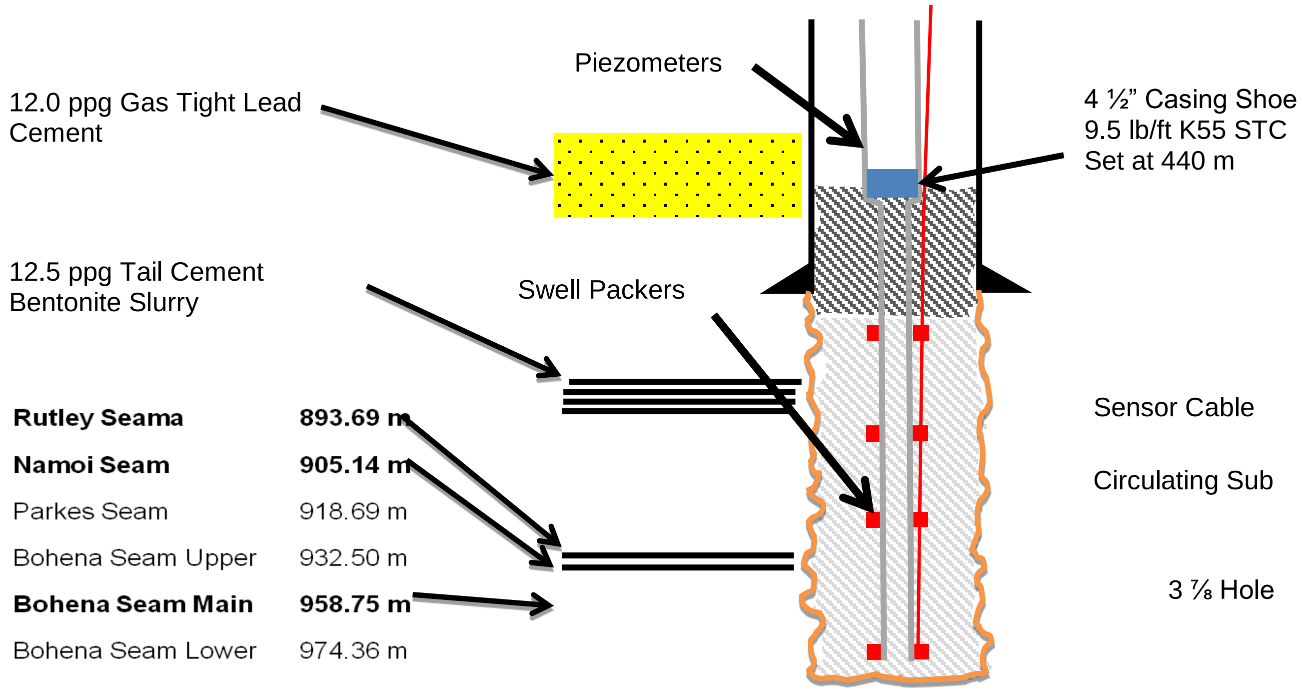


Figure 31. Example of a deep aquifer monitoring bore incorporating piezometers at several levels within the well. (Source: Santos)

As previously explained, management of produced water is a major issue for some CSG projects. The starting point for effective water management is to obtain a comprehensive understanding of the hydrogeology of the CSG basin, and advances in technology have greatly enhanced that understanding. Using isotopic analysis, the source and the age of groundwater can be established with a high degree of confidence. This provides the starting point for being able to model the impact of water produced on existing groundwater resources, including water and pressure drawdown in overlying aquifers, as part of a CSG operation and minimise that impact. The use of enhanced modelling software such as MODFLOW, which is able to integrate hydrostatic units with hydraulic heads, provides the capability to numerically model a range of development scenarios to minimise impact. If there is a need for any reason to model the geochemical behaviour of produced and groundwater, for example if the possibility of contamination exists, then additional components of the MODFLOW package can be used; also the specialist geochemical TOUGHREACT software package is available. In addition, systems for monitoring groundwater (Figure 29) and for the automation of individual bores (Figure 30) have advanced considerably in recent years.

Technologies have also greatly improved for managing produced water including flow back water associated with fracking, and recycling and blending of produced water. Desalinisation techniques have also improved, for example through reverse osmosis. Regulations in Queensland now ban the use of evaporation ponds and there is far greater consciousness of the need to manage surface water, particularly where salinities are high and this is likely to apply in NSW.

E. POTENTIAL IMPACTS OF A CSG DEVELOPMENT

E.1 FUGITIVE EMISSIONS

Fugitive emissions from CSG projects may arise from a number of sources. In the case of methane, these can include during pre-production operations associated with well completions, during gas production operations and leakage from pipelines and gas storage facilities. In addition, carbon dioxide emissions result from gas sweetening where the original gas is high in CO_2, from the fuels and energy used during operations and compression and, it could be argued, from end use such as in heating or power generation. However, here the discussion is restricted to the exploration phase through to transport stages and is not concerned with end use. It also focuses on methane. Methane has a global warming potential (GWP) of 25 compared to carbon dioxide (DCCEE, 2010). Cook et al (2013) quote the Climate and Clean Air Coalition (CCAC, 2013),

> that over 8 percent of total worldwide natural gas production is lost annually to venting, leakage, and flaring. In addition to U.S. $27 to $63 billion in energy and economic losses, these activities result in nearly two gigatonnes of CO_2 equivalent of greenhouse gas emissions per year, over 80 percent of which are methane emissions – making oil and gas operations the second-largest source of global anthropogenic methane emissions behind agriculture.

It is not known what proportion of this is from CSG, but it is likely to be no more than a few percent. Nonetheless, fugitive emissions are clearly a consequence of CSG activities and require consideration. In a review prepared by for the Department of Climate Change in 2012, Saddler lists the sources which account for the majority of methane emissions relating to CSG operations together with their share of relevant emissions and this information is provided below:

Normal operations: pneumatic devices and pumps	41%
Well workovers with hydraulic fracturing	19%
Well completions with hydraulic fracturing	16%
Pipeline leaks	8%
Gas engine compressor exhaust	7%
Dehydrators	3%
Gathering compressor leaks	2%
Produced water from coal bed methane wells	2%

As Saddler points out,

> In assessing the relative significance of these figures, it is essential to bear in mind the relative production volumes from the various types of gas resource. The 41% from normal operations is likely to be sourced mainly from conventional gas production, which accounted for about two-thirds of total US gas production in 2010. Hydraulic fracturing predominates in shale gas production, which supplied around a quarter of total gas in 2010, while CSG supplied only 7% or so. It follows that produced water from coal bed methane wells is a very

much more important source of emissions from CSG than the above percentages would, at first, suggest the approximate annual emissions factors used for the above sources expressed in terms of mass of methane, averaged over the regions and converted to metric units are as follows.

Normal operations: pneumatic devices and pumps	13 kg per device
Well workovers with hydraulic fracturing	177 t
Well completions with hydraulic fracturing	177 t
Pipeline leaks	0.65 kg/km
Gas engine compressor exhaust	5 g/h
Dehydrators	0.3 g/t methane

Fugitive emissions during exploration

Most of the fugitive emissions from this phase are similar to those arising from many commercial and industrial operations rather than specifically relating to CSG in that they are derived from transport (not necessarily regarded as fugitive emissions) and other field and office activities and are mainly CO_2. However it is important to make the point here that some areas underlain by CSG-bearing coals are characterised by natural venting of methane to the atmosphere through faults or via groundwater. In some instances exploration has been undertaken on the basis of identifying areas with anomalously high fluxes of methane in the soils, water or the atmosphere. This type of emission should not be regarded as “fugitive” to the extent that it is a natural phenomenon. But it does serve to make the point that it is important to document background levels of methane, so that natural methane emissions can be clearly distinguished from any fugitive methane emissions arising from CSG projects.

Emissions during the assessment and production stages

As in the exploration stage discussed earlier, CO_2 emissions at the assessment and production phases mainly relate to combustion of fossil fuels to drive the engines of the drills, pumps, compressors etc. required to produce CSG and to transport equipment, water and drilling muds etc. on and off the well site together with the preparation of the well pad.

There appears to be only limited information available on fugitive methane emissions associated with CSG production, with few recorded measurements in the USA (see O’Sullivan and Paltsev 2012 for discussion on shale gas, but relevant to CSG). In Australia, Southern Cross University (Santos and Maher) have measured methane emissions in southern Queensland; the study is presently undergoing peer review. However it is likely that emissions from CSG will be lower than for shale gas or conventional gas at the well head, given the somewhat simpler extraction and treatment processes involved with CSG including the lower gas pressure (close to atmospheric pressure). In most cases the CSG is of “pipeline quality” and requires minimal treatment. However in some areas, carbon dioxide can be up to 10% which is dealt with by blending it with low CO_2 gas rather than removing it. Whilst this produces a pipeline quality gas, it does mean at the end use, there is additional emission of CO_2 over and above that resulting from the combustion of the methane.

Emissions can also be generated during well completions, flowback and well workovers. The impact of these emissions can be reduced by flaring the gas or capturing the gas and using it. However under the present CSG PAL regulations in NSW, it is not possible for the gas company to sell gas from wells tests, meaning that there is a potential regulatory disincentive to minimize the fugitive methane emissions at the flow back and pilot stage. This issue of flowback methane and its mitigation is a much more significant issue for shale gas and has been discussed at length by Howarth et al (2011), O'Sullivan and Paltsev (2012) and Cathles et al (2012). The United States Environmental Protection Agency (EPA, 2012) has recently issued a set of standards for the oil and gas industry relating to reduction of emissions, including methane, from gas wells.

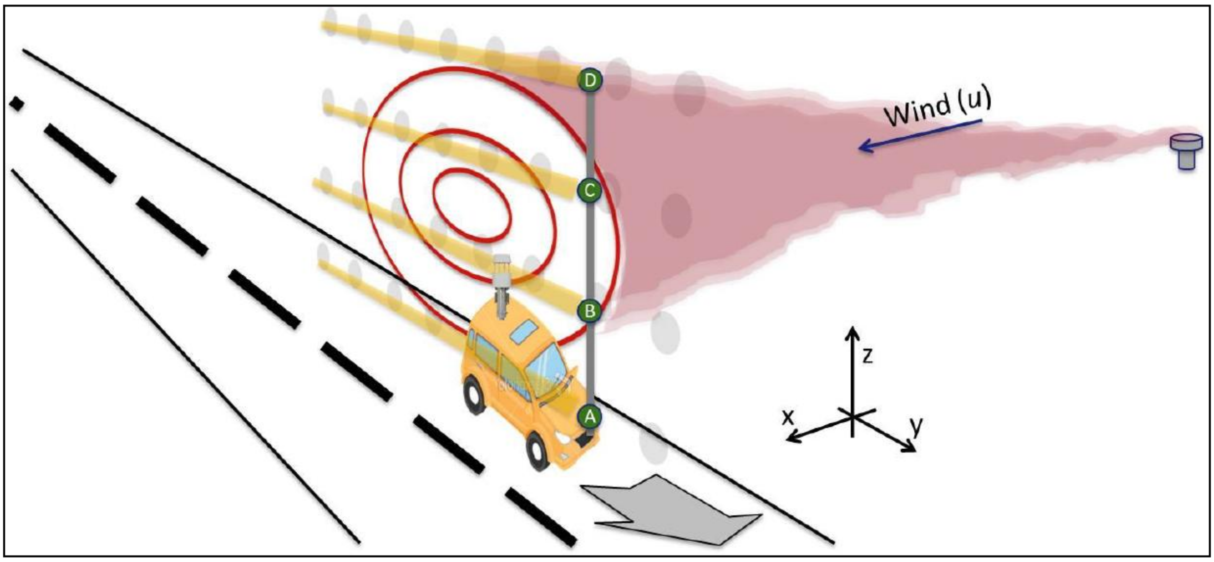


Figure 32. The Picarro Surveyor (shown here schematically) has the potential to provide clarity on the extent of fugitive methane emissions from a range of natural and anthropogenic sources. (Source: Picarro)

Fugitive emissions during processing and transport

Once production commences, any methane emissions are from unavoidable venting of methane during subsurface operations such as remediation operations, or exceptionally, unintentional leaks from pipelines and CO_2 emissions from the processing plants (companies have strict monitoring regimes to detect leaks should they occur due for example to a pipeline or valve failure . Measurements by Southern Cross University of atmospheric methane in areas of CSG activity have produced high atmospheric methane values apparently in excess of what might be expected. However the sampling program was quite limited and without a proper understanding of the background methane emissions prior to drilling, it is impossible to comment on the relevance of the reports in the press on the Southern Cross results.

In summary, inevitably some fugitive methane emissions result from CSG production and transport. The relatively low pressure of the gas in the gathering lines (see earlier) suggests that leakage from this stage is likely to be minor, with losses more likely occurring at the well head and the main pipeline. The lack of field data makes it difficult to be definitive about the magnitude of the losses. However as pointed out by Beck et al (Appendix 2; Cook et al, 2013), if the gas is displacing coal-fired power generation, then there is a significant net benefit in terms of greenhouse gas emissions from that gas use even when fugitive emissions are taken into account in a full lifecycle analysis. At the present time, there is only limited information available on fugitive emissions of methane associated with CSG operations. However the advent of the new Picarro instrumentation for methane measurement does provide a potential technology option for developing a better database, both prior to and during operations (Figure 32). (See the Air Pollution section below for a discussion on non-fugitive emission, CSG-related air pollution sources.)

E.2 CHEMICAL RELEASE

Accidental release of chemicals used in, or resulting from, CSG activities can potentially have adverse impacts on the natural environment. While spills are an issue that require specific mitigation, the industry already has in place rigorous procedures for minimising spills. If despite everything, a spill occurs; there are well-established industry procedures for remediation and for reporting the quantities of chemicals used (and spilled) and the number of impoundment ponds and holding tanks.

All companies have protocols in place for minimising the prospect of such incidents occurring and for remediating them, should they occur. Whilst the chances of them occurring may be low, they nonetheless can potentially result from the spillage of materials such as diesel used in the surface operations, subsurface injection or surface spillage of drilling mud additives and fracking fluids and emissions to the atmosphere.

Drilling fluids

Water-based drilling mud most commonly consists of bentonite clay (gel) with additives such as barium sulfate (barite increases the density of the drilling mud), calcium carbonate (chalk) or hematite. Various thickeners are used to influence the viscosity of the fluid, e.g. xanthan gum, guar gum, glycol, or starch of drilling fluids into permeable formations [Caenn et al, 2011]). The water-based drilling fluids used for CSG wells are for the most part relatively benign in terms of their chemical composition, for example, fertilizer-based (potassium sulphate) drilling muds are now commonly used for CSG–related drilling because they have a low salinity. In addition, companies increasingly aim to recycle the drilling muds to minimise disposal. The expectation of governments and communities (Cook et al 2013) is that companies provide full disclosure of all chemicals used in drilling muds, given that their composition, of necessity, varies with the geological conditions encountered in the well.

Hydraulic fracturing fluids tend to be more specialised and their composition (Table 1) is in part dependent on the preferences and experience of the service company. A fracking fluid may have 3-12 additive chemicals depending on the characteristics of the water and the coal being fractured. Each component serves a specific, engineered purpose. The United States Department of Energy (2009) has published a table of additive type, main chemical compounds and common use for hydraulic fracturing (US DOE, 2009), shown in Table 1 with specific concentrations of proppant and other additives. The proppants are typically inert materials such as silica and should not be regarded as “chemicals” in the sense that that do not constitute a potential chemical pollutant.

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive by-products	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion inhibitor	N, n-dimethyl formamide	Prevents the corrosion of the Pipe	Used in pharmaceuticals, Acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make up remover, laxatives, candy
Gel	Guar gum or hydroxyethyl	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavouring in food and beverages; lemon juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale inhibitor	Ethylene glycol	Prevents scale deposits in the Pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color

Table 1. Hydraulic fracturing fluid additives.

Note: The specific compounds used in a given hydraulic fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales. Sources: US Department of Energy, Office of Fossil Fuel and National

Technology Laboratory (April 2009). Modern Shale Gas Development in the United States: A Primer (p63) (US DOE, 2009).

The chemicals used during hydraulic fracturing, although at very low concentration (by volume) in the hydraulic fracturing water (0.1 to 0.5%), are causing gas producers to choose to adopt a number of actions summarised by Cook et al (2013):

- Revealing what chemicals are used in fracture stimulation treatments,
- Pointing out that those chemical are at very low concentrations,
- Communicating other areas where the public comes into contact with the same chemicals: for example the 'gel' used in fracture stimulation treatments is also found in cosmetics,
- Removing/ reformulating chemicals where needed and where possible. For example some fracture stimulation contractors can use UV light instead of a biocide to remove unwanted bacteria.

Drilling fluids and fracking fluids can be introduced into an aquifer if fractures from fracking extend beyond the coal and into an aquifer. However, provided best practice is adopted, the chances of this happening are low and in most instances, there is a high degree of vertical separation between the CSG source and the freshwater aquifer. (As previously mentioned, accidental surface spills can also constitute a source of chemical contamination and it is important to have reporting and remediation protocols in place.)

Air pollution

A further source of chemical contamination can arise from the discharge of volatile organic compounds (VOCs) to the air during production of the well (diesel fumes from generators, or from associated road traffic) or from the processing plant. A number of studies have been undertaken of the potential impacts of these chemicals on human health (American Public Health Association, 2012), though for the most part these studies have been concerned with shale gas. In Australia, the Queensland Department of Health (2013) undertook a study in the Darling Downs area and concluded that there was no evidence of adverse health impacts resulting from CSG operations in that area.

The occurrence of methane in aquifers in areas where CSG activities are underway has received some attention. Leakage of methane into an aquifer can occur as a result of a poorly completed well. But as pointed out earlier, a great deal of attention is paid to the satisfactory completion of production wells, with several barriers in the well and the casing-off of aquifers. Therefore the chance of leakage occurring from this route is low. Methane can also leak directly from the coal up along fractures and faults. The chances of this occurring could be increased if hydraulic fractures become over extended, although again there is usually a high degree of vertical separation between the coal seam and the fresh water aquifer, which minimizes the chance of this happening. As revealed by the NSW Department of Industry and Investment review of bore water geochemistry, in many areas of the state, water bores are naturally high in methane. It is therefore important to be able to determine whether anomalously high methane values in bores are a natural feature or the consequence of CSG activities.

E.3 IMPACT OF INFRASTRUCTURE

Infrastructure can impact both positively and negatively on the local community. The positive benefits can include new or improved roads, improved water supply and enhanced communications and job opportunities. The negative impacts can include noise, more road traffic, greater pressure on services and the local housing stock and land use conflicts. These have been discussed in some detail by a number of authors including ACIL Tasman (2011), Carrington and Perreira (2011) and Haslam Mackenzie (2008).

Impact on the natural environment

The environmental impacts of infrastructure developments can include the localized impact of noise associated with drilling activity, road traffic, impacts on some species, or the regional impact on the landscape. Retention ponds storing produced water may attract wildlife, but fauna deaths in treatment dams are not likely to be significant (Hein, 2012; Ramirez, 2009; Eco Logical Australia, 2013), and should be put in context of the loss of native wildlife in and around rural farm dams and the positive impact arising from access to a new source of potable surface water. Storing of saline or polluted water at the surface is likely to have a greater adverse impact. Access roads and well networks can compromise the landscape for productive agricultural and pastoralist activities as well as habitat values and scenic assets-–all evidence of the complex interplay of factors that require consideration.

As pointed out by Cook et al (2013, Chapter 7), landscape ecology, land use and water resources are all components of a highly connected and complex landscape system and it is necessary to take account of the cumulative impacts on this connected and complex landscape when considering broad scale CSG activities. At the same time it is important to take account of the fact that whilst many potential hazards and their consequences can be documented, it is necessary to also consider the likelihood of that event happening. Here, a risk analysis has not been undertaken as that was not within the terms of reference. All that has been done here is to describe some of the potential impacts on the environment, whilst bearing in mind that the likelihood of some of them occurring may be quite low.

Environment Australia (2000) provides a broad ecological characterisation of Australia and in NSW, the bioregion with the greatest level of CSG activity, is the Sydney Basin which is described as comprising:

> Mesozoic sandstones and shales, producing skeletal soils, sands and podzolics that support a variety of forests, woodlands and heaths within a distinctive landscape of sandstone plateaus and valleys. The Sydney Basin contains a number of important freshwater catchments that supply drinking water to Sydney and other major centres. It is a highly diverse region, containing coastal swamps and heaths, rainforests, tall eucalypt forest, dry eucalypt woodlands, and a number of important wetlands. It supports the Blue Gum High Forest, the Cumberland Plain Shale Woodlands and Shale-Gravel Transition Forest, the Littoral Rainforest and Coastal Vine Thickets of Eastern Australia and the Turpentine-Ironbark Forest in the Sydney Basin Bioregion ecological communities which are each listed as Critically Endangered under the EPBC Act, and also the Shale/Sandstone Transition Forest and Upland Basalt Eucalypt Forests communities, listed as Endangered under the EPBC Act. The Sydney Basin is a highly populated bioregion and is subjected to a number of development pressures.

Within the Sydney and Gunnedah Basins, there has been extensive land clearance and land use change including irrigation, grazing and agriculture as well as urban development. Nonetheless there are some important areas of natural vegetation remaining that could be potentially impacted by a range of developments, some of which, for example urban sprawl, are likely to have a more severe environmental impact than CSG developments. In addition there can be multiple vehicle visits required to a well site at the drilling stage and on-going traffic at the production stage, although the automation of production facilities and water handling has cut back vehicle movements considerably and again, against a background of traffic relating to urban spread, is likely to be quite modest.

Cumulative impacts have already occurred in Queensland, as a consequence of CSG projects and as summarised by Cook et al (2013, Chapter 7) include impacts on:

- habitat destruction and fragmentation by clearing of vegetation, potentially effecting biodiversity of local fauna and flora and to threatened species (Cushman, 2006)
- landscape function and on competing land uses
- impacts on drainage lines, flow regimes, volumes of surface waters and groundwater systems from water extraction and disposal, with implications for terrestrial and groundwater-dependent ecosystems
- contamination of water quality (surface and groundwater).

Of these, development of the infrastructure associated with CSG projects might occur due to clearing of bushland, fragmentation of patches of native vegetation and related impact on the ecology fauna mortality. This represents one of the more obvious potential impacts of intense development of CSG if it were to occur at the level of intensity evident in Queensland. A number of studies of fragmentation have been undertaken (Wiens, 1985; Forman & Gordon, 1986; Franklin & Forman, 1987; Saunders, et al., 1991; Ries, et al., 2004; Cushman, 2006; Fischer & Lindenmayer, 2007), related to various land use activities including agriculture, mining, urbanisation and recreation (e.g. Nelson, et al., 2006; State of the Environment, 2011; Riitters, et al., 2012). The large scale, permanent loss of vegetation has been demonstrated to result in land degradation (Standish, et al., 2006) and declining biodiversity (Wiens, 1985; Johnson, et al., 2007; Saunders, et al., 1991; Robinson, et al., 1995).Small sub-populations, which are not viable in their own right and where isolation prevents dispersal, can be vulnerable to impacts, resulting in a rate of local extinction that exceeds the rate of re-colonisation (Lambeck, 1997). Empirical observations suggest that population size is the main determining factor in extinction probabilities which is often approximated by patch area. Therefore, connectivity to existing local populations is very important. Within a bioregional context, the creation of new roads into intact areas can facilitate the establishment of invasive fauna, including invertebrates, which can disrupt ecological systems (Lach & Thomas, 2008; Eco Logical Australia, 2013). New road creation can also introduce weeds along the roadside and beyond.

These then are some of the potential impacts of a fragmented landscape. However it is important to bear in mind a number of factors:

- the experience of fragmentation in Queensland due to CSG has not yet happened in NSW and does not need to happen, as industry is now much more aware of the fragmentation issue

- technology developments, particularly the advent of multi-well pads and long reach horizontal wells has greatly decreased the footprint of CSG developments and decreased the likelihood of fragmentation in particular due to fewer well pads and connecting roads
- the water issues that have been so significant in Queensland are not of the same magnitude in NSW; for example in the Sydney Basin, water production is very minor and in the Gunnedah Basin is modest and improved systems for water reuse have been developed
- drilling muds and fracking fluids are now commonly recycled
- equipment is smaller and more manoeuvrable, meaning that tracks can be narrower
- the positioning of well pads is now more flexible due to the advent of long-reach wells, enabling more sensitive areas to be avoided.

Figure 33. Example of an AGL gas production facility at Spring Farm in the Camden area. (Source: Author)

In conclusion, the positioning and the nature of CSG infrastructure will vary with the geology and the topography. CSG developments do have an impact on the natural environment. However, impacts on vegetation and habitat in NSW are likely to be far smaller than the historical impacts of land clearing for agriculture, or urban development. Nonetheless, further loss on an already highly fragmented vegetation cover is obviously to be avoided and is subject to the NSW Government Department of Environment and Heritage (2013) regulations. The NSW Government's Strategic Regional Land Use Plans seeks to identify criteria for strategic agricultural land and define appropriate protection requirements under a risk management framework (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). The regional plans will aim to identify the most appropriate land use, whether mining, CSG extraction, conservation or urban development or a mixture of these activities and plans are being prepared for the Upper Hunter and Gunnedah regions

Impact on water

Issues relating to water have been discussed in various sections of this report, but it is perhaps useful to draw together some of those threads. The potential impacts of CSG on water resources arises from the quantity of water extracted from useable water resources, the quantities discharged into streams and water courses, impacts on groundwater aquifers and the contamination of water. Water management to minimise the extraction of and disposal to the surface of CSG-related groundwaters is important to minimise the impact of CSG on the environment, particularly at the pilot and production stages. However it is important to not generalise about water issues, as they vary greatly from basin to basin. For example CSG production in the Sydney Basin produces very little water whereas comparable developments in the Gunnedah basin produce much greater quantities

Surface water and groundwater are often connected components of the one hydrological system (Barlow & Leake, 2012). If drilling and hydraulic fracturing operations intersect aquifers and aquitards, this may cause contamination of potable aquifers. It may also interfere with aquifer discharge and recharge flow regimes. It is therefore important to take care to case producing gas wells (see earlier) to avoid extraction of potable water from aquifers, and protect them from contaminants. It is also important to re-use (where possible) or safely dispose of any “produced” water and avoid aquifer interference and perturbation of groundwater flow. Impacts might include those arising from abstraction of water on stream flow and on dependant ecosystems or the contamination of those systems. These could in turn impact on the connectivity of aqueous ecosystems. In addition, surface installations, roads, holding tanks and pipelines have the potential to interfere with surface flow of water. Subsurface activities can affect groundwater dependent ecosystems (Hatton and Evans, 1998) and perhaps some wetlands.

Care is necessary to ensure the safe storage, both on-site and offsite, of chemicals used for hydraulic fracturing, and impoundment and treatment of waste water. Spills could impact the surrounding ecosystem and result in the dieback or death of vegetation or contamination of riparian areas. The gas industry is very conscious of the need to take all precautions to avoid a major incident. The storage, treatment, transport and disposal of liquids including wastewater and saline water are also matters for regulation.

Eco Logical Australia (2013) summarises the potential incidents for shale gas that can lead to the contamination of aquatic systems and some of these may apply to CSG:

- spillage, overflow, water ingress or leaching from cutting/mud pits
- spillage of concentrated hydraulic fracturing fluids during transfer and final mixing operation (with water) that occurs onsite owing to:
    - spillage of flowback fluid during transfer to storage
    - loss of containment of stored fluid
    - spillage of flowback fluid during transfer from storage to tankers for transport
    - spillage of flowback fluid during transport to wastewater treatment works.

The issue of methane in wells has been previously discussed and can occur from CSG developments through unanticipated faults and fractures, but as pointed out previously, methane also occurs naturally in many aquifers. The source of the methane can often be determined by analysing the isotopic signature of the gas, with different isotopes of carbon indicating different gas sources (Osborn, et al., 2011).

Key concerns in the responsible management of the produced fluid are (USEPA, 2011; Frogtech, 2013):

- Unregulated release to surface and groundwater resources;
- Leakage from on-site storage ponds;
- Improper pit construction, maintenance and decommissioning;
- Disposal of large volumes of brine;
- Incomplete treatment;
- Spills on-site; and
- Wastewater treatment accidents.

Policies to manage co-produced water during CSG production have been developed in Queensland (Queensland Department of Environment and Heritage Protection, 2012) and NSW (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). Some of the re-use and recycle options include irrigation, stock water, aquaculture and industrial uses. Water entitlements compliant with the National Water Initiative (National Water Commission, 2003), and aquifer management plans are aimed at minimising changes to flow regimes in streams and water levels in groundwater aquifers, and the potential for contamination of both types of water resource. The allocation, entitlement, and use of surface and groundwater resources are covered by the Council of Australian Governments (COAG) *Water Reform Framework and the National Water Initiative.*

In 2010 and 2012, the National Water Commission (NWC) recommended a number of principles to manage the cumulative impacts of CSG water, summarized by Cook et al (2013, Chapter 8, are:

- The interception of water by CSG extraction should be licensed to ensure it is integrated into water sharing processes from their inception.
- Project approvals should be transparent, including clear and public articulation of predicted environmental, social and economic risks along with conditions implemented to manage the risks.
- Adequate monitoring, including baseline assessment of surface and groundwater systems, should be undertaken to provide a benchmark for assessing cumulative impacts on other water users and water-dependent ecosystems.
- Jurisdictions should work to achieve consistent approaches to managing the cumulative impacts of CSG extraction. Such arrangements should consider and account for the water impacts of CSG activities in water budgets and manage those impacts under regulatory arrangements that are part of, or consistent with, statutory water plans and the National Water Initiative.

- Potential options to minimise the cumulative impacts of extraction on the water balance should be pursued as a first priority. These options include aquifer reinjection, where water quality impacts are acceptable, and groundwater trading or direct substitution for other water use.
- If discharges to surface waters are unavoidable, discharges should be conditioned so that environmental values and water quality objectives, including water quality to meet public health objectives, are protected. In such circumstances discharges to ephemeral streams should be pulsed to avoid flows in naturally dry periods.
- Jurisdictions should undertake water and land-use change planning and management processes in an integrated way to ensure that water planning implications of projects are addressed prior to final development approval.
- Clear accountabilities should be identified for any short- or long-term cumulative impacts from CSG processes, clarifying which organisations are responsible for managing and rectifying or compensating for any impacts.
- The full costs, including externalities, of any environmental, social and economic water impacts and their management should be borne by the CSG companies. This includes, if not already in place, mechanisms such as bonds and sureties that deal with uncertainty and the timeframes associated with potential impacts. Given that these timeframes may extend for 100 or more years, current systems need to be re-evaluated.
- A precautionary and adaptive approach to managing and planning for CSG activities is essential to enable improved management in response to evolving understanding of current uncertainties. This includes impacts such as long-term reductions in adjacent aquifer pressures and levels, and impacts on environmental assets that are not adequately protected by current 'make good' mechanisms.
- Water produced as a by-product of CSG extraction, that is made fit for purpose for use by other industries or the environment, should be included in NWI-compliant water planning and management processes. This will enable CSG producers to manage this resource in accordance with the principles of the National Water Initiative.

New South Wales also has policies regarding aquifer interference (NSW DoPI, 2011; NSW DoPI, 2012; NSW EPA, 2012). Under the NSW *Water Management Act 2000*, aquifer interference includes (NSW Government, 2013):

- Penetration of an aquifer;
- Interference of water in aquifer;
- Obstruction of water in an aquifer;
- Taking water from an aquifer in the course of carrying out mining or any activity prescribed by the regulations;
- Disposal of water taken from an aquifer in the course of carrying out mining or any activity prescribed by the regulations.

Therefore in summary, aquifer interference and contamination could potentially occur as a result of CSG production, but if best practice is followed, the likelihood of this occurring is low.

E.4 CUMULATIVE IMPACTS

Many parts of eastern Australia are being subjected to a range of developmental issues and cumulative impacts relating to urban growth, transport, increased water needs, mining, agriculture, tourism and forestry. These activities impact on biodiversity, vegetation, flora and fauna species, soils and local water supplies for ecosystems, on people and other industries. CSG developments add to these cumulative impacts through surface activities (roads, drill pads, storage areas, water storage and use, pipeline installation, processing plants) and subsurface activities (production of CSG, production of water, disposal of water, fracking). Therefore it is important to extract CSG in a manner and in locations that do not unduly compromise agriculture, water resources, alternative land uses, and landscape function (O'Neill, et al., 1997; Tongway, 2005) using knowledge of Australian landscape processes, together with specific landscape, geological and hydrological data. These and other elements are all components of a highly connected and complex landscape system and it is important to take account of the cumulative impacts on this connected landscape that are important. As pointed out in Cook et al (2013, Chapter 7), "Planning tools are now being developed to assess cumulative risk (Shoemaker, 1994; Eco Logical Australia, 2012) and these, along with older risk assessment tools, appear to provide a means to manage multiple land use pressures and protect biodiversity and landscape function".

Like many other land uses, CSG poses some risks to water, soil, vegetation and biodiversity, and has the potential to impact on the capacity of natural resources to supply existing and future human and ecological needs. Nonetheless it also has to be recognised that CSG operations may have far less impact on the natural environment than agricultural and urban developments. Rehabilitation is a feature of the CSG industry and it is often difficult and sometimes impossible to recognise areas that were once well pads a few years ago or where a pipeline was installed a year or two ago. Similarly the production area is usually a low profile, fenced area of approximately 6mx6m (Figure 33). The gas processing plant (Figure 26), such as that in the Camden area, has an impact comparable to that of a small industrial facility with related (though generally modest) traffic, noise, waste, visual and light impacts in an area of a few hectares The less obvious potential impacts of CSG that could add to regional cumulative impacts relate to water extraction, water disposal, water storage and chemical contamination (Nelson, *et al*., 2006; State of the Environment, 2011; Riitters, *et al*., 2012). Cumulative impacts may potentially be on drainage lines, flow regimes, volumes of surface waters and groundwater systems including terrestrial and groundwater-dependent ecosystems, and contamination may affect water quality (surface and groundwater).

Landscape fragmentation such as that which has occurred largely as a result of past practices is one of the most obvious and perhaps one the most significant cumulative impacts. As discussed earlier, it can result in habitat destruction and fragmentation by partial or complete clearing of vegetation associated with roads, tracks pads (the extended pad along which a drill rig can be moved) and infrastructure, and the effects on biodiversity of local fauna and flora, potentially including threats to threatened species (Cushman, 2006). The creation of new roads into previously undisturbed (intact) areas can facilitate the establishment of invasive fauna species into remote areas and can also introduce weeds along the roadside and beyond (via vehicles and fauna). However it has to be said that as a result of regulations and company best practice, there is a clear recognition of the need to avoid such an outcome. Increased fire risk is one of the impacts also mentioned from time to time, but there is no evidence that this is significant; on the contrary, the gas companies have systems in place to minimise this danger, with rapid response protocols that would serve to decrease rather than increase the impact of bush fires in CSG areas.

Cumulative impact on agricultural land has been one of the more contentious issues in recent years, particularly in Queensland and to a lesser extent in NSW, with competing land and water issues. Landscape fragmentation due to the density of drilling in some areas is perhaps an especially obvious cumulative landscape issue which can be disruptive to agricultural activities; this may be less of a problem in the future in some areas, with the advent of multi-well pads. The issue of cumulative impact on water resources whether actual or perceived is also highly contentious in some areas. Legislation and planning is in place which seeks to repair or prevent these and other impacts (Cook et al 2013).

In summary, the infrastructure required by the CSG industry does have a cumulative impact on the landscape, but it is important to keep the extent of that impact in perspective; it is generally less than that associated with many agricultural land clearance practices and far less than that associated with urban development. Nonetheless it is additive to a range of other activities that also impact on the landscape, the natural environment and resources and agricultural land.

F. FRACTURE STIMULATION AND WELL INTEGRITY

F.1 FRACKING FOR CSG AND SHALE GAS

Hydraulic fracturing (fracking) to stimulate gas production has been used by the petroleum industry for many decades, including in Australia (see earlier discussion on fracking). There are some similarities in its application to coal and shale in that in both instances, the purpose is to increase the permeability of the rock, thereby increasing the flow of gas from the coal seam or the shale to the production well. In addition to increasing the fracture permeability, it also gives access to a greater volume of gas-bearing rock thereby increasing the total volume of gas that can be produced from a single well. However there are a number of important differences between coal seam gas and shale gas production that reflect their differing geology. A number of these features impact on the application of fracking to the two types of gas production

Frequency of fracking

All shale gas plays need to be hydraulically fractured (fracked) to stimulate gas production. Many of these wells need to be fracked multiple times. In contrast, many CSG projects do not requires fracking. For example there are no plans to use fracking in the Gunnedah Basin; in the Sydney Basin, CSG wells are commonly fracked but the number of fracks per well is small, with just a single phase of fracking. In contrast shale gas wells often require many phases of fracking.

Type of fracking

In the United States fracking is almost invariably undertaken for shale gas projects in horizontal wells to produce vertical fractures. In Australia it is unclear the extent to which vertical fracking from horizontal wells will be used for shale gas, because in many areas, the Australian stress field is predominantly compressive, meaning that fracking in vertical wells may be the preferred method for Australian shale gas. Fracking in CSG wells in Australia is seldom if ever undertaken in horizontal wells; where it is deployed, in the Sydney basin for example, it is always undertaken in vertical wells.

Hydraulic pressures

The pressure required to frack shale is high due to the depth of the rock (2-3000m), the relative strength of the shale rock and the need to maximise the reach of the hydraulic fractures. In contrast, the fracking pressure used for CSG is low due to the rock being shallower (less than 1000m), the comparative weakness of coal and the need to restrict the reach of the hydraulic fractures because the coals are generally much thinner than the shales.

Induced seismicity

Overall the likelihood of fracking resulting in induced seismicity is judged to be low in both shales and coal although the fact that higher hydraulic pressures are needed for shale may mean that it is slightly more likely to occur in shales than in coal. Conversely the coals are weaker and shallower, which may mean that CSG fracking is more likely to be felt at the surface than fracking in shales. However the evidence overwhelmingly suggests that the risk of induced seismicity is low . For example in its review of shale gas The Royal Society and the Royal Academy of Engineering (2012) states: “There is an emerging consensus that the magnitude of seismicity induced by hydraulic fracturing would be no greater than 3 ML (felt by few people) and resulting in negligible, if any, surface impacts.” A number of studies conclude that induced seismicity is more likely to arise from deep disposal of fluids than from fracking (see recent review by Ellsworth, 2013).

Fracking fluids

The composition of fracking fluids is adjusted to match the requirements of the rock being fractured. In general the composition of the fracking fluid used for CSG is likely to be less viscous than that required for shale gas (because coals are “softer” than shales) and is also likely to have a lower volume of proppants (because coals are more likely to have open fractures or cleats than shales). The USDoE (2009) has summarised the additives in a fracking fluid used for shale gas projects (which will differ somewhat for CSG–related fracking). This information is provided in Table 1. It should be noted that since this Table was compiled in 2009 there have been a number of improvements made to fracking fluids, with the aim of ensuring more benign additives. The specific compounds used in a given hydraulic fracturing operation will vary depending on company preference, source water quality and site-specific characteristics.

F.2 MANAGING THE RISK OF CONNECTIVITY BETWEEN THE COAL SEAM AND AQUIFERS DURING FRACKING

One of the primary tools for managing risks to containment arising from fracking is by developing an accurate picture of the subsurface geology including the hydrogeology and the geomechanics of the various rock types. Once fracking is underway, there is a need for careful monitoring (see below for discussion on methodologies). This provides a guide to whether or not hydraulic fractures have remained within the coal seam or have extended beyond the seam and into an overlying or underlying geological formation (which may or may not be an aquifer). One of the most common indicators that a fracture has extended beyond the seam is a marked change in pressure, indicating that the fracture has penetrated a rock type with a different characteristic (such as rock strength or permeability) than the target coal. Sometimes the extension of the fractures beyond the coal may become evident from a marked increase in the amount of water produced from the coal and/or a change in the chemical composition of the water.

It is also possible for fractures to propagate towards an aquifer along a pre-existing transmissive fault. This possibility can be minimised by undertaking geomechanical modelling to predict fault orientation behaviour and avoid fracking in the vicinity of faults using high resolution seismic surveys to accurately map faults. These prior steps, along with application of one or more of the monitoring techniques discussed below, minimise risk. Finally it may be necessary to stop hydraulic fracturing if fracture growth is observed beyond that which might reasonably be expected. A “traffic-light” system has been suggested for shale gas fracking, where green (go ahead) amber (caution) and red (stop) that relates to the increasing magnitude (1 or less, to 3 or more in magnitude) of microseismic activity (Royal Society, Institution of Engineers, 2012).

F.3 TECHNIQUES TO MONITOR THE PROGRESS OF HYDRAULIC FRACKING

A comprehensive summary of techniques for monitoring hydraulic fractures (quoted below) is provided by Cook et al (2013, p 63-64) and whilst this was undertaken primarily with shale gas in mind, it is nonetheless relevant to CSG.

1. Microseismic Sensors: The key measurement during hydraulic fracturing is fracture growth, both in orientation and extent. This is required in real-time (< 5 minute time delay). Fracturing fluid injection can cause lateral movement or slip along natural fractures in the reservoir and the surrounding rock, and this produces a microseismic signal that can be measured by a long array (60-120 m) of accelerometers/geophones located in an offset monitoring well, situated approximately 100 m or more away at comparable depth. In essence, this technique triangulates the location of sounds made by rock breaking during fracturing. Accuracies of 15m are cited, using one to three listening arrays (Schlumberger, 2006; Halliburton, 2007). In actual operations, microseismic measurement may only be used if an appropriate (deep) offset well is available. The sensors and insertion tools are generally designed for temperatures up to 175ºC (~350º F), and between 175-200º C (~350-400º F) is a temperature range where specialist suppliers are required. Microseismic measurement can be problematic above 200º C (~400º F) (Santos Limited, 2013). (Temperatures of this magnitude are not encountered in CSG wells, because they are much shallower than shale gas wells.)

2. Tiltmeters: The opening of a fracture at reservoir depth causes small displacements (rock deformation and tilt) that can be sensed (with resolution better than one nanoradian) by an array of tiltmeters either located in shallow (~10 m) offset wells at the site surface, or more sensitively in a deep offset well at comparable depth to the fracturing events, providing information on fracture orientation and direction (azimuth) (Schlumberger, 2006). Tiltmeter resolution can be better than 1 nanoradian, although background noise and drift can be problematic in certain locations (Pitkin, et al., 2012).

3. Pressure Sensors: Downhole pressures provide an indirect measurement of fracture height, showing characteristic features that correlate with fracture initiation, propagation, height growth (or lack of height growth), containment and closure. Pressure sensors are connected to the production casing, as well as the outer casings to monitor well integrity.

4. Temperature and Flow Logging: After a hydraulic fracturing operation, logs of temperature and flow along the well provide information correlated with fracture location and hence growth (and also fracture height for vertical wells).

5. Proppant Tagging: Radioactive isotopes tagged to the proppant can be subsequently analysed to locate where different stages of proppant go, and hence the fracture location.

6. Chemical Tracers: can be added to the hydraulic fracturing fluid to improve understanding of fracture fluid loss and flowback efficiency.

7. Temperature Measurement: Shale formations are at higher temperatures than hydraulic fracturing fluid at the surface. Cooling due to injected fluids can be detected to provide data on hydraulic fracturing performance.

8. Fibre-optic Sensors: Measuring temperature, pressure and sound provide real-time information on fracture location in a well. Fibre-optic sensors are particularly useful for downhole measurements of high pressure/high temperature conditions, beyond the limits of electronic gauges (Pitkin, et al., 2012).

9. Photography: Downhole, side-looking cameras have been developed to provide images of fracture growth. They are limited to low pressure and clear fluid regimes.

10. 3D Seismic: Using a seismic source and a grid of geophones on the surface, a 3D seismic survey can accurately image reflected seismic waves utilising multiple points of observation, to provide a representative image of a volume of subsurface geologic features and formations via a computer-aided reconstruction. Importantly this can map the location of aquifers and pre-existing fault risks to be avoided by fracture stimulation (Resolution Resources International, 2009).

Whilst the above list of techniques is comprehensive and all can potentially be applied to CSG wells, the reality is that for the most part they are applied to more expensive and deeper wells rather than to shallower, relatively simple and less costly CSG wells. As a consequence, monitoring of CSG-related fracking is more likely to be done using pressure monitoring and flow logging. However, tiltmeters and the use of fibre-optics monitoring cables, may also be fairly cost effective for CSG.

F.4 TECHNIQUES TO ASSESS WELL INTEGRITY

The engineering of wells has been previously outlined and demonstrates that the setting of casing for example relies on a high level of knowledge of the downhole conditions, including the location of the coal seams, the disposition of aquifers etc. In general, only the vertical well is cased with steel casing, which delivers drilling and fracking fluids down the well at the drilling stage and the gas and water at the production stage. Where a horizontal well is used in conjunction with a vertical well, the horizontal well is seldom if ever cased and steel casing would not be used. A blow-out preventer is connected to the casing at the surface to control pressure while drilling. A well integrity test is carried out after each casing string has been cemented by pressurising the well bore with water, with the pressure depending on the depth and the type of casing; pressure monitoring is important to identify potential leaks in the casing. Ensuring that the cement seals are effective is important to prevent aquifer contamination (American Petroleum Institute guidance document HF1, 2009). Downhole acoustic logging is used to test the bond strength of the cement to the pipe and to the formation wall for each cemented string (Cook et al, 2013).

Cement is a long-lived seal, with examples of 40-year-old cemented wells exhibiting good isolation under pressure testing. Centralisation of the casing strings, displacing all mud prior to cementing, achieving sufficient cement height and avoiding gas migration through the cement as it sets, are some important details to be addressed. Special additives to the cement protect against gas migration, high temperatures, mineral acids and other factors. Non-toxic cementing additives based on cellulose have been developed and applied.

It is relevant to note in the context of well integrity that as part of a program to assess well head safety, 2719 well sites across Queensland were inspected (http://mines.industry.qld.gov.au/safety-and-health/well-head-safety.htm). The key findings were that of the 2719 sites:

- 5 well sites had leaks of a recognised flammable risk. These posed a minimal safety and health risk to workers and the community given the volume of gas emitted and other safety controls in place.
- 29 well sites had leaks that were below the flammable range but at a level requiring action under the Code of Practice. These posed very little or no safety and health risk to workers and the community.
- All 34 leaks were fixed.
- Gas stream testing showed there were no public health risks from these gas emissions and no toxic substances were found.

In summary, all of these measures discussed to this point help to ensure that aquifers are protected from risks arising from well failure, such as radial leaks (movement of contaminated or saline water or methane through casing into rock formation) or annular leaks (vertical movement between casings, or between casing and rock formation). Best practice guidelines for well construction and integrity are set down by the API (Well Construction and Integrity Guidelines, 2009) and it is important to recognise that well failure is rare in a well-regulated environment (Watson & Bachu, 2009). Nonetheless as pointed out in the Alberta Government discussion paper (2012),

> hydraulic fracturing has expanded in use to many different reservoir rock applications with a range of types and sizes of fracture treatment. This evolution has raised the potential risk of wellbore failure both in the well being hydraulically fractured and surrounding wells. Consideration of these advanced drilling and completion technologies for the development of unconventional resources must be undertaken with the goal of ensuring that wellbore integrity is maintained.

Long-term management (50 years or more) of abandoned gas wells to avoid the risk of cross-contamination of waters or gas emissions to the atmosphere is vital and must receive regulatory attention.

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