Independent Review of Coal Seam Gas Activities in NSW

Information paper: Fracture stimulation activities

September 2014

EXECUTIVE SUMMARY

Fracture stimulation is a technique used in underground resource development including coal seam gas extraction, mining, geothermal, shale and tight sands activities to fracture rock and place a proppant and, in the case of coal seam gas, to enable methane to move more readily through and from coal seams. In addition to enhancing gas production, fracture stimulation is used earlier in drilling programs to help characterise the local stress and reservoir conditions and to test and understand the response of the target resource to stimulation treatment.

Prior to any drilling or fracture stimulation activities, the geology of a basin must be well understood, for safety, environmental protection and economic reasons. Coal is heterogeneous and complex. Significant exploration effort using sophisticated characterisation and monitoring technologies is undertaken to gain a better understanding of local geology and hydrogeology. This influences decisions about where production wells will be drilled, and what well-types, design and technical approaches will be used to extract the resource.

Geophysical and reservoir characterisation and mapping of the resource formations are essential in determining whether fracture stimulation is required. Fracture stimulation techniques vary across individual resource basins as well as between different resource types such as coal seam gas, shale gas or oil, tight gas or basin centred gas and conventional oil or gas. Worldwide conventional and unconventional petroleum resources have been subject to about two million individual well fracture activities under many different geological conditions with a substantial literature record providing valuable engineering and environmental information to inform regulators and operators across the world. The coal resources of New South Wales have different basin characteristics; fracture stimulation techniques appropriate for the local geology will be required to optimise resource recovery and to account for environmental protection constraints.

Significant advances in modelling capabilities have occurred. The application of models enable petroleum engineers to plan the technical approach (design) of a fracture program to match the constraints of the geological setting; select the optimal stimulation techniques, fluid types and additives and injection rates for application; and plan and predict the pressure response and fracture propagation pattern with increasing accuracy.

Once fracture stimulation begins, there are a range of technologies and software programs (with varying degrees of accuracy) to monitor and visualise the progress of a fracture treatment, and allow interventions (e.g. stopped, and shut-in or flowback – depending on whether pressure is to be maintained) to be undertaken should the fracture treatment deviate from that planned.

The development of newer directional drilling techniques means that wells can access more gas resources. In NSW, in many situations directional drilling can mitigate and in places eliminate the need for stimulation. Furthermore, coals drilled horizontally in NSW often don't respond with enough additional production to justify fracture stimulation.

In the last decade, there has also been focus on developing tools and materials to increase the efficacy of fracture stimulation treatments and exploring alternatives to, or strategies to minimise, the use of water and chemicals, driven by resource recovery economics and public concerns.

To date, hydraulic fracture stimulation using water-based fluids has been the predominant commercially deployed technique in Australia with limited experimental application of high pressure nitrogen and propellants (high energy gas fracturing). Elsewhere, a wide range of fluids and gases has been deployed for high pressure stimulation at scale where the geology, well constraints and business risk allow. As with other technologies in this field, the quality and accessibility of information and data is fundamental to our understanding and management of risk. Closing the loop between data captured during and following a fracture into the planning and modelling process for future activities helps to refine modelling and improve the understanding of the risk and management of fractures to a specific setting.

Given the heterogeneous nature of coals and basins, it is important that we have appropriate legislative and regulatory mechanisms in place to manage and optimise the growing body of knowledge and research. Knowledge of local and basin geology combined with advances in drilling and fracture stimulation techniques and capabilities in subsurface characterisation, modelling and monitoring must be employed to produce best practice. Emerging knowledge should inform both industry practice and the regulatory framework.

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1 INTRODUCTION

Fracture stimulation (fracturing, fracking or fraccing) is a technique used to fracture rock to encourage economic production flows from wells. It is a technique that has been used in a wide range of applications, including water wells, oil, conventional gas, shale gas, coals seam gas, geothermal, mining, etc. In the case of coal seam gas (CSG), fracture stimulation is undertaken to increase permeability thus enabling gas to move more readily through and from a coal seam to the well. *Hydraulic fracturing* utilises pressurised fluids to fracture the reservoir rocks and includes the use of water, foams and liquefied gasses (such as carbon dioxide), acids and petroleum liquids. However, water and water based gels are by far the most common fluids used. Other stimulation techniques include the use of pressurised air or other gases, propellants, electromagnetic pulses and heat.

Term of Reference 6 for the independent review of coal seam gas activities in NSW (the Review) entailed the preparation of papers on specific elements of CSG operations, including hydraulic fracturing, to inform the public and policy development.

Hydraulic fracture stimulation has been examined in a number of the expert information papers (Anderson, Rahman, Davey, Miller, & Glamore, 2013; Carter, 2013; Cook, 2013; Drummond, 2013; Gore & Davies, 2013; Khan & Kordek, 2014; O'Neill & Danis, 2013; Ward & Kelly, 2013) and other expert opinion (Cook, 2012; Jeffrey, 2012; Pinczewski, 2012, 2013a, 2013b) commissioned by the Review. This paper draws on this advice, supplemented with other expertise to examine factors influencing the decision to use fracture stimulation in CSG activities; to report on current stimulation techniques and to report on current technologies used to model and monitor fracture growth, e.g. Economides and Martin (2007); Holditch (2007); King (2012); Thakur, Schatzel, and Aminian (2014); US EPA (2004). Scientific understanding of CSG associated with fracture stimulation and their management are summarily canvassed, but are dealt with separately in the Review paper “Managing environmental and human health risks from coal seam gas activities” (CSE Risks, 2014a). While focusing primarily on hydraulic fracturing, other techniques are described given the interest expressed during the course of the Review regarding perceived risks and alternatives.

As noted in the Initial Report, many industry stakeholders placed hydraulic fracturing low on the list of risks associated with CSG extraction (CSE, 2013). In contrast, expressed public concerns centred on its perceived associations with water consumption and contamination and other negative health and environmental effects. For example, 24% of submissions to the Review related to chemicals used in the process and its effect on water quality.

It is important to recognise that much of the discussion about fracture stimulation is based on the experience in the United States and Canada in relation to shale deposits, accounting for some 85% of the worldwide use of the technology (Beckwith, 2010, cited in Commonwealth of Australia, 2014), whereas NSW efforts are currently focused on extracting gas from coal seams under very different geological conditions. This has important implications both for the value proposition of applying the technology and understanding of associated risks.

There is a major difference in the scale of operations in hydraulic fracturing between CSG and shale resources. Across the world, development of CSG resources have been in the depth range 200-1,000 metres (m) whereas shale resources are typically between 1,500 to 3,000m. The fracture stimulation pumping setup (frac spread) on the surface for CSG may run to 10,000 hydraulic horsepower with four to six high pressure pump units whereas for shale stimulation the power demand may be as high as 50,000 hydraulic horsepower and use 30 pump units. Water use is also much greater for shale than for CSG. Given these substantial differences caution must be applied when considering comment on hydraulic fracturing in the absence of resource description.

1.1 FRACTURE STIMULATION EXPERIENCE TO DATE

Experiments with and industrial treatments using hydraulic fracturing in oil and gas reservoirs date from the late 1940s in the United States (CSE, 2013) although it wasn't until the late 1960s that significant expansion occurred with advances in technologies enabling extraction from unconventional sources (e.g. CSG, shale, tight sands) (Jeffrey, 2012). Additional advances occurred with developments in drilling techniques (late 1980s) and fracture stimulation techniques and constituents (late 1990s) (CSE, 2013). According to industry figures, over 2 million stimulations have been undertaken worldwide to date (APPEA, n.d.), with around 8% of over 4,200 production wells stimulated in Australia (APPEA, 2014).

The NSW experience of fracture stimulation is more limited. From records available to the Review, 148 wells of 897 drilled (580 of which are CSG wells) have been subject to fracture stimulation in this State, undertaken in the period 1981-2010, of which 66 are still producing (NSW Trade & Investment Division of Resources and Energy (DRE), personal communication, 25 September 2014). In May 2011 the NSW Government imposed a temporary ban on fracture stimulation. Initially for a period of 60 days, it was extended until the September 2012 release of two Codes of Practice for CSG – one on well integrity, the other on fracture stimulation activities. In July 2011 the NSW Government also announced a ban on the use of benzene, toluene, ethylbenzene and xylenes (BTEX chemicals) in all CSG drilling and fracture stimulation activities. This was formalised in policy from 6 March 2012 (Policy Number TI-O-120) which also required that all CSG drilling additives and CSG fracture stimulation additives must be tested by a National Association of Testing Authorities (NATA)-certified laboratory and demonstrated to meet Australian drinking water health guideline values for those chemicals.

Since the lifting of the prohibition and introduction of the *NSW Code of Practice for Coal Seam Gas fracture stimulation activities* in September 2012, only one proposal has been approved in NSW, the AGL Waukivory Pilot Project (PEL 285) in Gloucester which includes the fracture stimulation of four exploration wells (OCSG, 2014).

1.2 STRUCTURE OF PAPER

The remainder of this report summarises and reports on expert advice:

- Chapter 2 reports on current fracture stimulation techniques
- Chapter 3 outlines factors influencing the decision to use fracture stimulation
- Chapter 4 reports on approaches for subsurface characterisation, modelling and monitoring
- Chapter 5 provides observations from the Review and states that the key issue is whether emerging knowledge is informing industry practice and government regulation.

2 TECHNIQUES USED IN FRACTURE STIMULATION

Fracture stimulation is used in CSG to widen existing fractures and create new ones. Proppant (usually sand) is placed into the hydraulic fractures to keep them open and preserve their conductivity. It enables extraction from otherwise unrecoverable or economically unviable resources; an increase in the rate of extraction by up to ten times to that of unstimulated wells and is sometimes used to boost declining productivity, particularly towards the end of the life-cycle of a well or reservoir. As previously discussed, fracture stimulation is not required in all wells and the decision to use the technology will be subject to cost-benefit considerations, having regard to the likelihood of success, the additional cost of treatments relative to site-specific characteristics and regulatory requirements.

The dominant international fracture stimulation technique in use to date remains hydraulic fracturing. However, driven by public concerns about environmental and human health impacts and costs, there has been significant research effort on developing other materials and approaches to increase the efficacy and decrease adverse risks of fracture treatments; devising less environmentally damaging additives; and exploration of alternatives to or means of minimising the use of water and chemical additives.

Where a decision to deploy fracture stimulation is made, factors influencing choice of technique include basin, geology and coal characteristics; availability of expertise in technological advances and the efficiencies they offer; regulatory requirements and associated risks and costs. The factors are discussed in Chapter 3.

2.1 HYDRAULIC FRACTURING TECHNIQUES

Hydraulic fracturing involves the injection of fluids to the point where the fluid pressure is higher than the minimum in situ stress and may include the use of water, foams or fluidised gases such as carbon dioxide (CO_2). The fluid is combined with a solid proppant (typically sand) to keep the fracture open and may include chemicals or other additives.

In a fracture treatment, a suite of liquid mixtures are progressively injected into a cased well at pressure, travelling through the designed perforations in the well casing to reservoir coals, widening existing cleats, or creating new fractures in the process. The fracture will be extended by continued injection of liquid. The proppant assists to keep the fractured channel in the coal open and the injected liquid and water from the seams is produced back at the end of the treatment as flowback water.

The amount of pressure and liquid required will be primarily influenced by the type of rock, target depth, permeability, design fracture half length, and materials used. For example, the pressure required to fracture shale is high due to the depth of the rock; its typical depths (1,500–3,000m) and higher in situ stresses that exist at that depth. Some additional pressure is also required to overcome fluid friction when injecting at the rates used. In contrast, the pressure used for CSG is lower due to the typical depths involved (<1000m) with lower stress levels and using lower injection rates because the need to restrict the reach of the hydraulic fractures in the thinner coals. The quantity of water required for a treatment will vary for similar reasons as will the rate of fracture growth. In CSG typical propagation length or distances from wells range from 200-300m and generally speaking, the rate of growth in coals early on will be approximately 10m per minute and slowing to less than a few metres per minute towards the end (Jeffrey, 2012).

Unlike shales, which can be several hundreds of metres thick, coals are more often thin and comprise several layers inter-bedded with shales and sands. As a result, hydraulic fracturing design may extend across several seams if they are in relative close proximity and the energy requirements are not excessive. Otherwise individual seams will be targeted. The choice of design will depend on the nature of the coal deposit. For example, in the Queensland Surat Basin, coal seams are described as “stringy” where individual coal deposits are discrete but are repeated in the overall measure.

2.1.1 Fracture fluid constituents

There is significant literature on chemicals and other material additives used in fracture stimulation (Commonwealth of Australia, 2014; Cook, 2013; CSE, 2013; Jeffrey, 2012; Kucewiez, 2014). Key performance qualities for fracture fluids include viscosity (aiding creation of a fracture of optimal width and improved proppant transport); capacity to maximise fluid distance (to extend the fracture); capacity to transport optimal amounts of proppant; and capacity to minimise the need for gelling agents (reducing the complexity of the fracturing activity and the number of pumping stages required and reduced costs) (US EPA, 2004).

While varying from company to company and well to well, the proportions are typically 90% water, 9% proppant and ~1% chemicals. The latter serve specific purposes centred on operational efficiencies – maintaining permeability, transporting proppants in and optimising gas flow out at the lowest fracture injection rate with the least amount of pressure required. The various chemicals and mixtures would be pumped underground in separate injection stages. There may be up to 100 for a well over a period of hours when multiple seams are targeted.

While sand is the most common proppant, alternatives include nut shells, ceramics or bauxite (Beckwith, 2010, cited in Commonwealth of Australia, 2014). Ceramics and sintered bauxite would only be considered for shale operations where significantly higher pressures are expected. As CSG basins across Australia are relatively shallow the preferred proppants are typically graded silica sands. Despite size fraction processes used in their preparation where contaminants may be separated, fine particles continue to be present in the final product. These particles may be released at various points during transfer (e.g. from the bulk product containers through to eventual sand blending in the hydraulic fracturing spread). Material released to the atmosphere including fine silica dust can reach high airborne concentrations near the plant and can migrate off site to adjacent property. The United States Department of Labor have issued a hazard alert and information sheet on the issue (OSHA & NIOSH, 2012a, 2012b). The various source areas in the sand handling train can be addressed through basic dust emission control measures (Anderson et al., 2013).

The number and combination of additives used in a typical fracture treatment depends on the well conditions, water characteristics and rock properties. Typical additives include acids and alkalis to control the pH balance of the fracture fluid (which affects the fluid viscosity); acids (to dissolve residual iron, cement, and rock particles from drilling operations and perforations, and calcium carbonate if present in the coals); bactericides to prevent bacterial growth (which could contaminate the formation and inhibit gas flow); gels, including cross-linked gels to enhance proppant transport performance (addressing viscosity limits of water and improved functionality over less expensive linear gels); guar gum to create a gel (to transport the proppant; enzyme breakers to dissolve fracture gels (to aid fluid extraction and gas transmission); and friction reducers and surfactants such as emulsifiers and non-emulsifiers (to increase fluid recovery).

In the US, ‘slickwater’ stimulation fluids are widely used in shale formations. These are low viscosity fluids designed to travel very long distances with lower friction pressure (e.g. up to two kilometres). They carry the proppant burden by higher fluid velocity in the wellbore and by ‘dune transport’ in the fractures (a type of repeated re-suspension movement). The vertical wells typical of the CSG industry in Australia pose less of a fall-out problem until the perforation is reached. At this point, horizontal wells are not typically fractured (see Chapter

3) and the geological conditions may make it more likely that a gel formulation is used initially for this purpose (possibly transitioning to slickwater if the conditions are suitable).

In Australia, most operators currently use water-gel mixtures (APLNG, 2013 and Golder Associates, 2010, cited in Commonwealth of Australia, 2014). There has been a growth in proprietary formulas and 'green' additives or alternatives in response to expressed concerns about chemical use – for example, use of UV light instead of a biocide to remove unwanted bacteria (Cook, 2013).

While water is the predominant fluid base, it can be problematic e.g. due to volumes required; causing water saturation and hindering gas flows in water-sensitive coal formations; and adding to the volume of produced water that needs to be subsequently managed.

2.1.2 Non-water based fracture fluids

Fracture fluids can also be based on oil, methanol, or a combination of materials to produce foams (US EPA, 2004), however oil and methanol are not relevant to CSG. Each principal fluid system entails management of complex characteristics and interactions and each has challenges and relative advantages and disadvantages. In respect to CSG, cross-linked gels typically demonstrate the greatest proppant placement and propped length, but can cause formation damage and are more costly than water. Water with or without proppant is lower cost and causes little damage, but more volume is required to extend the fracture to the same distance and place sufficient proppant. Nitrogen foam is good for proppant placement and fracture length but has a high cost and, when used in deeper wells at higher pressure, it loses its advantages (Gandossi, 2013).

Liquid CO_2 has been used at commercial rates in Canada and the US with environmental advantages including reduction or elimination of water and chemical use. It is particularly advantageous in coal seam gas formations as it has a higher solubility and displaces the methane, enhancing gas production and achieving some degree of carbon sequestration as it remains underground. Used for stimulation, its advantages include creation of more complex micro-fractures and better clean-up performance of any residual fluids. However, it presents both advantages and disadvantages in terms of proppant; it must be transported and stored under pressure and is corrosive in the presence of water.

Literature on cryogenic liquids (liquefied gases that are kept in liquid state at very low temperatures) suggests they have specialised roles that may not be applicable to CSG; e.g. cryogenic liquid nitrogen (N_2) has been used as a fracture fluid but is rarely employed in commercial operations due to special piping and equipment requirements; while the combination of hydraulic fracturing with the injection of cold CO_2 is at concept stage, with application proposed for tight formations. These fluids also have potential to damage the wellbore because of the large thermal-induced stress changes that occur.

Foams, including those created from combining N_2 gas and liquid CO_2 have been used at commercial scale (e.g. Canada; the Appalachians in the US); advantages including reducing or eliminating water usage, reducing chemical additives, posing fewer environmental challenges and easier clean-up post-treatment) (Gandossi, 2013; US EPA, 2004). It is understood nitrogen foam has been tested in Australia (R. Jeffrey, personal communication, 17 September 2014). However, in the case of N_2 or CO_2 only fluids, these are costly; require higher surface pumping; their flow behaviour can be difficult to predict and the material displays decreased fracture conductivity due to low proppant concentration.

Air or gas (e.g. N_2 gas) can be injected at pressures exceeding those in the target formation and flow volumes exceeding the natural permeability of the rock to generate fractures. Advantages include eliminating the need for water and chemical additives and use in water-sensitive and low permeability basins. However, use of gas is limited at depth and suffers from poor ability to transport proppant, with associated susceptibility to closure. In the case of air, introducing oxygen into the coal seam is hazardous.

Nitrogen gas (without proppant) has been used extensively in the shallow and dry formations in Alberta's Horseshoe Canyon, where low reservoir pressure (permeabilities <1-20mD) and water sensitive coal precludes the use of water. Gas production is from multiple overlying seams. This technique does not appear to have been trialled in Australia (where coals are not water-sensitive).

2.2 NON-HYDRAULIC TECHNIQUES

Other fracture stimulation techniques in use at commercial scale or at experimental/ pilot stage include electric pulses, solid propellants, and heat. Key advantages of most include reduction or elimination of water and chemical use in the process. Some may have application to CSG, although most are more specific to shale or oil production.

While trialed in shale, traditional explosives (e.g. nitroglycerin in various forms) have been largely superseded by newer technologies due to well damage; unpredictable results and safety considerations. However, solid propellants that deflagrate rather than detonate (similar to rocket fuel, a burning process that splits rather than compacts rock), create a series of fractures propagating along a direction dictated by the perforation geometry. These have been used in the US and are in early trial stages in Australia. However, its application appears specialised. It has the advantage of not requiring proppants or other chemicals while achieving permanent fracture openings, but fractures are typically of limited extent (in the order of 20-25m and around 65m in hard rock), limiting the stimulation effect (D. Campin, personal communication, 28 September 2014).

Using pressure waves or high energy pulses generated by electrical discharge are also reported at concept or pilot stage (Gandossi, 2013; US EPA, n.d.-b). A review by Knight (2012) of available literature on use of lasers to fracture reservoir rock concluded the technology for enhancing productivity is not yet at a commercial stage although work was progressing on the use of laser perforation tools to improve the liquid flow characteristics of the reservoir rock and to facilitate hydraulic fracturing. It could also enhance drilling efficiencies (Gahan, 2006).

2.3 FRACTURE PROGRAM DEVELOPMENTS

There have been increasingly sophisticated developments in fracture stimulation programs, particularly in shale operations to increase the efficiency of extraction, matched by drilling advances (discussed in Chapter 3). This includes developments in multi-stage fracture stimulation programs combined with multi-lateral horizontal drilling, including the ability to compartmentalise lateral wells and stage treatments; undertake simultaneous, discrete or repeat treatments; enhanced drilling and visualisation capabilities; and both an increase in and reliability of fracture and completion options and materials (e.g. coiled tubing equipment for targeted fracturing; pressure controls).

The impact of advances can be seen in completion times - for example the average completion time per stage of lateral drilling and fracture programs decreased to two hours per stage in 2010 from 85 hours per stage two decades earlier (Bobrosky, 2010). Similarly, drilling experts advised the Review of significantly improved visualisation capabilities in seams as narrow as 20-30cm.

While concurring with Carter (2013) that well completions and fracture propagation to aquifers are the key risks (that can be effectively mitigated or avoided), Pinczewski (2013b) notes the high rate of innovation and wider trend in the petroleum industry towards use of mini-fractures along the length of horizontal drilled sections. This approach may prove most effective in coals with well-developed natural fracture or cleat systems, and is less likely to result in fracture propagation outside coal seams, and therefore mitigate (or even largely eliminate) risks to aquifers.

Although still at the 'emerging directions' stage is use of N_2 and CO_2 gas alone or together to enhance recovery, which in low-permeability coals is used in conjunction with fracture stimulation.

The most effective applications for use of CO_2 to enhance recovery and for sequestration is subject to major R&D programs (e.g. Center for Oil and Gas- Energy & Environmental Research Centre Bakken CO_2 Storage and Enhanced Recovery Program). However, there has also been growing interest in combining gas applications. The two-facet approach uses N_2 to reduce the partial pressure of methane (CH_4) so it will more readily desorb, while maintaining total pressure (and therefore the cleats open and the flow towards the well). Carbon dioxide, having a higher affinity to adsorb in coal will 'swap' with methane – the CO_2 adsorbing and CH_4 desorbing. The combination of N_2 and CO_2 also helps overcome the problem of using CO_2 on its own – the molecules being larger than methane, the coals expand, making the cleats smaller and decreasing production flows (US EPA, n.d.-a; Zuber, 2014) , and as discussed previously, poses an advantage for CO_2 storage. The limitation is that CO_2 and N_2 cannot be forced into low-permeability coals unless hydraulic fracturing is used either before or during the gas treatment. Without fracture stimulation their use is limited to higher permeability coals where they can be used to produce additional methane when wells are reaching the end of their productive life.

3 FACTORS INFLUENCING THE USE OF FRACTURE STIMULATION

The economic viability of CSG extraction depends on the rate and volume of resource recovery within accepted environmental and human health parameters relative to costs and energy market prices. Unstimulated CSG recovery rates are primarily determined by the permeability of the coals, prevailing geological conditions and the stage of resource extraction. These factors will have a direct bearing on drilling choices; decisions on whether or not to deploy techniques such as fracture stimulation and the expected efficacy of selected stimulation techniques for enhancing resource recovery under specified conditions.

Given the heterogeneous nature of coal and basins, a detailed understanding of geological and hydrogeological characteristics, combined with careful testing, modelling and monitoring are essential (see also Chapter 4). In recent years, increasing sophistication of drilling technologies has had an impact on both drilling programs and decisions to use fracture stimulation.

3.1 GEOLOGICAL FACTORS

Coal is a carbon-rich sedimentary rock with a block-like structure divided by fractures or 'cleats'. These cleats typically consist of two approximately orthogonal vertical fracture sets called the face cleat and butt cleat. The face cleat is the better developed and more continuous of the two and is associated with a higher permeability. A naturally occurring gas, CSG is typically (in NSW) composed of over 95% methane and is present inside the cleats and adsorbed on the surface of the coals. Kept in place by the pressure of groundwater in and around the coal seam, a sufficient reduction in hydraulic pressure (whether naturally occurring or induced) will allow the gas to de-sorb, mobilise through the water filled cleat system and follow a flow path in the direction of least resistance, e.g. towards a well (Commonwealth of Australia, 2014; Cook, 2013; CSE, 2013).

The ability of the gas to mobilise is fundamentally determined by the permeability of the coal (i.e. the measure of its ability to allow fluids to pass through it). Generally speaking, the higher the permeability (measured in millidarcies) the higher the gas production rate and the less need for stimulation (Pinczewski, 2013b). Due to its geological history, NSW generally has low permeability coals. For example, the Sydney Basin coals range from 1-10 millidarcies (mD) compared with the Queensland Bowen and Surat basin coals, with ranges up to 500mD (CSE, 2013; Ward & Kelly, 2013).

Permeability itself is affected by a complex array and intersection of factors that also have a bearing on the decision to use fracture stimulation. These include coal properties; gas properties and basin properties (Cook, 2012, 2013; Jeffrey, 2012; Pinczewski, 2012; Ward & Kelly, 2013).

3.1.1 Coal properties

Coal is highly complex and heterogeneous in nature. Formed from peat, its physical and chemical properties vary according to its level of maturation (rank); density (proportion of minerals and moisture); porosity (ratio of pore volume to total volume); saturation (amount of a particular gas that the coal holds); and thickness of the seam (CSE, 2013). Low permeability may be due to lack of cleats associated with low maturation; variation in material make up; anthracite rank; and a high degree of mineralisation or cleat destruction through mineral filling associated with water flows (Zuber, 2014). Cleat mineralisation has been particularly problematic in NSW (Pinczewski, 2013b). Further, the interplay between cleat permeability and matrix permeability is highly complex (Cook, 2013; Ward & Kelly, 2013). While some cleat fractures are orthogonal (appearing in ordered matrices at perpendicular angles), others are highly variable and may impede gas flows. If the natural cleat pattern is not in the right direction or the cleat aperture is too tight to enable a natural flow of gas, stimulation may be considered to enhance the flows.

Coal seams vary according to their sedimentary environment and history of tectonic forces and subsurface stress regimes. Structural events resulting in folding and faulting can result in increased permeability. However, features that may adversely influence extraction rates include splits, variable joint patterns in the coal seam; faults that may cause displacement; and 'washout structures' where coal is replaced by other forms of sedimentary rock (Cook, 2013; CSE, 2013). In places, vertically 'stacked' reservoirs with coal seams of variable thickness are common, presenting other drilling and production challenges (Zuber, 2014).

3.1.2 Gas properties

Gas properties also impact on permeability – being type (a mix of CH_4 and CO_2) and pressure. The permeability of coal is higher for CH_4 than CO_2, but the ratio of the two varies in Australia, although in NSW it is typically over 95% CH_4 (Lama, 1995, Bartosiewicz and Hargraves, 1985, cited in Aziz, Caladine, Tome, Cram, & Vyas, 2007). Gas pressure also affects permeability, but is complex, varying in its affect according to the type of gas.

3.1.3 Basin properties

It is estimated that only 20% of most basin gas in Australia can be found at depths of less than 900 metres, and to date, most commercial production is from drilling to around 1,200m (Zuber, 2014). Background papers for the Review by Cook, Ward and Kelly, and O'Neill and Danis suggest the general trend is of permeability decreasing with depth, as the natural cleats are compressed, which may increase the likelihood of using fracture stimulation although deep coals are drier (Cook, 2013) However, Pinczewski (2013b) comments that the relationship between variation in permeability and depth is complex and current understanding of this factor poor.

It would appear that NSW resources have some characteristics that are distinctly different from say the relative uniform seams that are common in Queensland. These relate to the relatively common occurrence of faults extending throughout the basins and the complicated nature of groundwater interactions where there is a very real need to have three dimensional (3D) and pseudo 3D (P3D) models focusing at the individual well level but tied into a basin overview. The discharge/recharge relationship between groundwater and surface waters could be disrupted at a local level and it is necessary to apply high quality diagnostics to a greater extent than could be expected in the more uniform basins such as the Surat or Powder River. Modelling is discussed further in chapter 4.

In addition to the natural fracture pattern, the stress field (horizontal and vertical forces) and rock strength will have a major bearing on well engineering, gas production and whether to use (and the effectiveness of) fracture stimulation (Cook, 2013; Ward & Kelly, 2013).

The orientation of stress fields is highly variable throughout Australia but have a consistent orientation at a local scale (Hillis & Reynolds, 2003, cited in Ward & Kelly, 2013). For example, in the Sydney Basin the horizontal stresses in many rock strata are much higher than the vertical stresses (Pells, 2011, cited in Ward & Kelly, 2013).

The stress regime has implications for predicting the migration direction of induced fractures, as fracture stimulation predominantly enlarges pre-existing fractures such as coal cleats (US EPA, 2004) and the direction of fracture propagation will be in the direction of the greater stress. The formation of new fractures may also result, but are fewer in number compared to the natural fractures. In this context, horizontal fractures could be seen to be more desirable with less likelihood of the fractures extending to overlying formations.

In addition the orientation of the dominant stress regime may change with depth in a particular location, and therefore strongly influence fracture geometry. With most of the coals located under 1,000m horizontal fracture development is expected to occur more commonly (due to overburden pressure). With formations below about 1,500m fractures tend to be vertical due to it being the plane of least stress (Halliburton, 2007). However, the less stiff coal seams typically carry lower horizontal stresses and most fractures initially grow as vertical fractures in the coal itself (Enever, Jeffrey, & Casey, 2000).

The type of rock as well as the stimulation injection rate applied will also influence the likely maximum propagation (length) of a stimulation treatment. For example, with natural cleating, a fracture in a coal seam is expected to travel a maximum of 100-300m in contrast with up to 600m in shale. This is due to the energy dissipation through the natural cleats in coal and the loss of fluid into the surrounding coal whereas the lower level of natural fractures and low porosity of shale allows much more efficiency of energy transfer to the fracture propagation. Shale fracture treatments are also carried out at a higher injection rate, which results in more efficient fracture growth and longer fractures.

The hydraulic fracturing techniques developed in the very wide variety of coal seams and shale resources across the US provide a rich source of engineering experience to draw upon in the careful development of the NSW coal resources.

3.2 TECHNOLOGICAL FACTORS

Advances in drilling techniques, particularly non-vertical drilling, may mitigate the need for or use of fracture stimulation or use of chemicals when fracture stimulation is used to enhance permeability and extraction rates, although in some cases a company may seek to fracture a horizontal well. As with other decisions, this will be influenced by relative cost and geology.

The dominant drilling approach to date for CSG extraction in NSW has been drilling of vertical wells, the approach, tools and skills adapted from long-standing petroleum industry practice. Directional (or deviated) drilling, being the intentional deviation of a wellbore from the path it would naturally take, has been used in the conventional petroleum industry since the 1920s, but horizontal in-seam drilling at depth for CSG and shale dates from the early 1990s in the USA, with the first Australian well completed in the same year (Carter, 2013).

'Horizontal drilling' is a form of 'directional drilling' in which the well being drilled is deviated onto a horizontal plane (Carter, 2013). Usually beginning as a vertical bore, the well can extend hundreds to thousands of metres underground, bending until it runs parallel with the gas seams. From the point of deviation from the vertical, multiple radials can branch out, tapping multiple seams, or can be directed and drilled within a single seam, providing greater exposure to the target reservoir and maximising the gas extracted which can decrease the need to use fracture stimulation (Carter, 2013; Pinczewski, 2012).

The use of horizontal drilling for the recovery of unconventional gas is a relatively recent phenomenon in Australia, and at this point, hydraulic fracturing in conjunction with horizontal drilling in CSG wells appears seldom used (Cook, 2013), although it is relevant for deeper shale and tight gas (2-4kms underground) and was applied in three exploration wells in Western Australia in 2012 (Carter, 2013).

In NSW, of the 79 non-vertical wells drilled (75 of which are CSG wells) between 1985 and 2014, 12 (all CSG wells) were subject to fracture stimulation, of which nine are still in production (NSW Trade & Investment, DRE, personal communication, 25 September 2014). It is understood that the fracture stimulation was not always successful (AGL, personal communication, 1 July 2013).

S-type well construction has been used in Queensland and is commonly used in the United States, where a single pad may house a number of wells with an intermediate horizontal section allowing a displacement of about a kilometre prior to a vertical completion.

The use of directional drilling is site-specific and will be subject to cost-benefit considerations previously discussed. Key advantages are increased access to gas by increasing the conductive pathways and contacting much larger volumes in gas bearing coals than an unstimulated vertical well; ability to align the drilling direction to take advantage of natural cleat alignment; and the ability to run multiple wells from a single pad ('pad-based drilling'). The latter requires less overall land access and may result in less surface disturbance by decreasing the infrastructure typically associated with multiple, closely spaced vertical wells. However, each (individual) pad will be larger than that required for single vertical wells owing to the complexity of equipment. A comparison of factors that inform decisions on the use of vertical versus directional drilling approaches is in Appendix 2.

Regardless of well type, application of best practice standards for well completion and assessment through pressure testing of casing; logging of cement bonds and inspections at critical safety points is essential (Carter, 2013; Pinczewski, 2013a). Well completion can be more difficult in horizontal wells (Carter, 2013).

Emerging evidence from the United States shales is that hydraulic fracturing and horizontal drilling are not responsible for fugitive gas leaks into drinking water wells. A study on drinking wells overlying the Marcellus and Barnett Shales found that gas contamination or leaks into water wells were caused by poor well integrity (well failure, leaks through annulus cement and/or leaks through production casings) (Darrah, Vengosh, Jackson, Warner, & Poreda, 2014; Ohio State University, 2014).

As the field of horizontal drilling has matured, Carter suggests knowledge gaps lay not with the technology, but its application - particularly the combined use of horizontal drilling with hydraulic fracturing in a CSG context and lack of detailed knowledge of site-specific hydrogeology and how this impacts fracture propagation. Publicly available groundwater data and baseline surveys are needed to address this. Recommendation 2 in the Initial Report (CSE, 2013) addressed the need for shared, integrated and publicly available data. Chapter 4 of this report discusses subsurface modelling and monitoring capabilities in further detail.

4 SUBSURFACE CHARACTERISATION, MODELLING AND MONITORING

The two key challenges with fracture stimulation are to ensure that the induced fractures do not grow excessively out of the targeted coal seams and risks to water resources are managed.

A range of sophisticated subsurface characterisation, modelling and monitoring techniques, developed and improved over the past four decades, are available to help characterise and model coal formations, adjacent rock layers and aquifers. Together with real-time monitoring, these techniques both inform the fracture treatment plan as well as enabling responses during the treatment.

This chapter discusses currently available practices in monitoring and modelling for use during all stages of CSG extraction, from exploration to post-production. The chapter first considers techniques for characterising the reservoir in which fracture stimulation will take place, as well as the surrounding strata. Information from these processes feed into initial models that characterise geology, faults, groundwater systems and the like. As further data is collected through early stage fracture stimulation activities, the data is used to further refine the models or build new ones. The process is both iterative and dynamic, with measurement and data used to build more robust model assumptions and improve the statistical certainty of the models.

4.1 CHARACTERISATION

Prior to the design of fracture stimulation programs, information about the subsurface needs to be collected (Beckwith, 2010, cited in Commonwealth of Australia, 2014; DTIRIS, 2012; Jeffrey, 2012; Pinczewski, 2012; Ward & Kelly, 2013) regarding:

- geological stratigraphy (e.g. geometry of units), geological anomalies and structures (e.g. existing fractures and faults) and continuity of the target formation
- geophysical and geomechanical properties (e.g. strength; compressibility; Poisson's ratio; reservoir pressure; formation modulus; formation temperature, and the tendency for the coal to form fines and rubble (elasticity)
- geomechanical conditions (e.g. strength of faults, bedding planes, natural fractures, and principal stresses – regional stresses; closure stresses – pressures required to keep fractures open)
- hydrogeological properties (e.g. porosity, permeability of cleats, permeability of matrix, compressibility)
- hydrogeological conditions (e.g. water pressures in coal seam and other strata).

A range of investigation techniques are used to collect these data. These include geological mapping, geophysical logging tools, geophysical surveys (2D and 3D seismic, electrical, gravity, etc.), borehole lithological logs, geomechanical field tests, and geomechanical core analysis testing (Commonwealth of Australia, 2014).

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 describing the physical parameters of reservoirs (API, 2009).

The process of understanding, characterising and modelling the subsurface is iterative. For example in addition to the investigation techniques described above, initial water monitoring is used as part of the characterisation process (i.e. to determine hydrological properties and conditions) while ongoing groundwater monitoring (see Section 4.3 below) is part of continuous refining of the characterisation of the subsurface. Similarly, the results from the post-fracture analysis of a seam treatment will help inform and further develop the subsurface characterisation. It is important to review the models of the subsurface as further data become available.

4.2 MODELLING

Fracture stimulation models are used to help predict the direction, the shape, and the length of the fracture. These models are usually employed by specialist service companies and at times by operators themselves or consultants. Back analysis of the treatment using modelling is also done quite often, especially when a new area is being developed. This provides knowledge about how induced fractures are likely to respond in the coal seam and allows fracture programs to be adjusted.

In NSW, fracture stimulation modelling has and is being done. The biggest modelling gap or limitation is the ability of the models to handle fracture growth and its interaction with rock layers and bedding planes around the coal seams. This will be site specific, e.g. in the Camden area, conditions are such that height growth into the sandstones above the coal measures is not expected (R. Jeffrey, direct communication, 19 September 2014). Greater confidence about fracture growth predictions in specific areas can be provided through extensive site characterisation and modelling and inclusion of microseismic and tilt meter monitoring in pilot wells (see section 4.3).

Fracture stimulation modelling is one of a much larger set of models undertaken as part of CSG planning and operations – summarised in Table 4.1. In some instances, these broader models provide input into the fracture model (e.g. geological modelling). In other cases, the reverse is true and fracture model information is used in other models (e.g. groundwater models need to use a permeability value(s) and fracture conductivity based on data from the fractured seam).

Models are simplified versions of true systems. They must be constructed using sufficient characterisation data to capture the behaviour of the system being studied. Nevertheless, as representations, they always contain uncertainty. Simplifications will inevitably be made to all models, including geological and groundwater models, and therefore justifying assumptions is important to allow independent scrutiny of the model (Ward & Kelly, 2013). Ideally, multiple models would be used for each CSG site to predict the impact of faults on fluid flow (Ward & Kelly, 2013).

Conceptual subsurface geological modelling builds a 3D image of the geological structure (e.g. strata, faults, etc.) and distribution of physical properties (porosity, permeability, etc.). The 3D models represent hydrostratigraphic layers for flow models, map pathways of connectivity, and map fault planes and fracture networks (Ward & Kelly, 2013). 3D models are very data intensive and are operated on very high capability supercomputers. To date, 3D geological models that take into account faults and fracture networks for proposed CSG sites in NSW are limited (Ward & Kelly, 2013).

In contrast, fracture stimulation design for individual wells utilise 3D or P3D models that have lower data intensity levels. Data input for 3D and P3D models include layer by layer data extending across porosity, formation thickness, permeability and in-situ stress. The design engineer will run many series of simulations to consider variations in input parameters to build as robust a fracture design as possible with best available data to achieve optimum return and economic benefit. As a basin is progressively subjected to hydraulic fracturing, data from each well will inform and improve estimates of fracture performance. The process applied in Queensland is for the operator to develop their specific models and for the regulator to build and refine a regional model with input from each of the operators in the basin. Other water quality/piezometric data from state owned wells or other competent wells may inform the model.

Groundwater models, informed by data collection to improve statistical confidence, can help describe potential impacts to groundwater and surface water bodies through changes in hydraulic connectivity and conductivity from CSG activities and other industries (CSE, 2013). The groundwater models need to account for changes in the conditions due to fracture stimulation (Commonwealth of Australia, 2014).

Groundwater model outputs are indirect inputs into fracture stimulation models, however, if an aquifer is close to the coal, its properties will be assessed to judge what sort of risk it poses, with more effort put into characterising the rock and stress in the layers between the coal and the reservoir. If the groundwater model identifies local issues and hydraulic conductivity anomalies associated with faults or other linear features, then this information should be used to inform the design of the fracture stimulation plan.

It is 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 fracturing in the vicinity of faults using high resolution seismic surveys to accurately map faults (Cook, 2013).

Table 4.1: Modelling techniques

Modelling approach	Description	Confidence/Limitations	Further information
Geological	Modelling of the structure of the coal seam and other layers(including faulting and fractures in these layers) in relation to groundwater flow using information from piezometers, packer, pump tests, cores, geophysical tests, etc.	Model is simplified but evidence to support model assumptions allows scrutiny.	(Ward & Kelly, 2013)
Geophysics & Geomechanics	Using high resolution seismic (or electrical) surveys to map faults and to predict fault orientation behaviour and avoid fracturing in the vicinity of a fault. Reduces possibility for fractures to propagate toward an aquifer along a pre-existing transmissive fault.	Electroseismic surveying has the capability to identify coal beds and aquifers based upon their conductivity responses. In trial phase in Queensland. Ultra high resolution seismic surveys can provide extremely accurate images of subsurface features.	(Cook, 2013; Ward & Kelly, 2013)
Fracture stimulation**	Fracture simulation software predicts fracture geometry and orientation using known and measured information about local and regional geology and in situ stress.	Early estimates of permeability, porosity, in-situ stresses, mineralogy, fracture barrier locations and other variables make early modelling less accurate; refined as first well data is collected and as remote monitoring data is incorporated.	(Commonwealth of Australia, 2014; King, 2012)
Groundwater flow and transport	Information is collected on regional and local piezometric heads that inform a groundwater flow model.	Operators in NSW are now required under the Aquifer Interference Policy to submit a Groundwater Monitoring and Modelling Plan as a condition of their licences.	(Commonwealth of Australia, 2014; Ward & Kelly, 2013)

**The fracture stimulation modelling is the key model for predicting fracture growth and movement within the seam.

4.3 MONITORING

Real time monitoring is undertaken during fracture stimulation to check the fractures reach the target area and do not grow into adjacent aquifers (Cook, 2013; Drummond, 2013).

However, some growth out of seam is not uncommon and may even be part of the design plan. For example, if there are three seams in a sequence, the design may call for stimulation of one and growing the fracture into the other two rather than separate treatments of each seam. This method is often used if the seams are each thin.

A range of different techniques are available with various cost benefits. Techniques that provide more detail and information are typically used during early stages of development, particularly in new fields to obtain data to refine and build models and to develop the fracture program, as in the mini-fracs and leakoff tests (King, 2012). The primary monitoring methods for describing fracture orientation, length, height, width and placement are described in Table 4.2. These can be broadly grouped as:

- far field monitoring techniques, utilising tiltmeters and microseismic surveying. These are delicate and expensive but able to produce an image of the stimulation process - microseismic analysis providing real-time images of the activity in progress. These technologies are likely to be applied in the early stages of basin development
- direct near-well techniques are comprised of logs, e.g. production, temperature, borehole image and caliper logging. Data provided is restricted to the very near well environment (e.g. less than 0.5m)
- indirect fracture techniques, including modelling of net pressures, production data analyses and pressure transient analysis. These are the most widely used methods to estimate shape and dimensions of the created fractures. The 3D or P3D model is informed with data collected to recalibrate the design estimates.

Real time fracture monitoring technologies allow operators to observe and monitor the progression of a fracture and modify or stop injection if the fracture is not proceeding as expected. In a case of the Walloon Coal Measures in Queensland, multiple technologies were used to investigate fracture patterns (Denney, 2011, cited in Commonwealth of Australia, 2014), which helped to better define the complexities of the fracture growth over using a single method alone (Commonwealth of Australia, 2014).

Once experience and data on how a particular seam responds to fracturing has been gathered, then further fracturing tends to use less expensive techniques such as pressure monitoring and analysis of production data.

A marked change in monitored pressure when fracture stimulation is used can indicate that the fracture has left the seam and has penetrated a rock type with a different characteristic (such as rock strength, stress, 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 (Cook, 2013).

Fracture treatments can and are stopped or shut down for various reasons. The stimulation process can be stopped immediately if some anomaly is noted. All the applied surface energy will abruptly cease (within a few seconds) however the formation is under a state of elevated pressure that may take days to months to return to a pre-stimulation pressure state. During this time a well could be shut-in, thus retaining initial pressure or it could be relieved through the flow-back choke valves. The decision of whether to shut-in or relieve would depend on the nature of the problem and how rapidly resources could be sought of fix it. With CSG the shut-in pressure is likely to dissipate relatively quickly due to the inherent fractures in the formation and the native hydraulic conductivity).

Monitoring for additional parameters that may indicate an impact caused by hydraulic fracturing is undertaken during all stages of CSG extraction, from baseline to post production. This includes well integrity monitoring (e.g. pressure testing, cement bond logs, etc.) and environmental monitoring in the surrounds near the well (Commonwealth of Australia, 2014). Groundwater monitoring of aquifer parameters such as water quantity, pressure, flows and quality provides information pre- and post- fracture stimulation activity to ensure that aquifer contamination or connectivity has been avoided. A range of potentially automated sensors, (e.g. piezometers, temperature loggers, electrical conductivity and pH meters, dissolved oxygen optodes, redox potential sensors, remote sensors) are available to do this. This topic has been covered in extensive detail in the Initial Report (CSE, 2013), the *Placement of Monitors in NSW Report* (CSE, 2014b) and Anderson et al. (2013).

In NSW the Office of Water plans to drill additional bores and introduce advanced computer modelling to provide baseline water assessments of the Gloucester, Gunnedah and Clarence Moreton basins (DPI, 2014). Use of microseismic sensors, tiltmeters, pressure sensors and rate monitoring appears standard in NSW.

Table 4.2: Fracture stimulation monitoring techniques

Technology	Description	Application	Confidence/ Limitations	Further information
Mini Frac or Diagnostic Fracture Injection Tests, stress tests	Small fracture stimulation treatments (Pump-In/Decline Tests) of fluid properties and pressure decline parameters to determine key reservoir structure and rock mechanic properties and fracture growth behaviour (e.g. permeability and pressure) and test assumptions and early models. It is important to establish communication with all the coal layers before testing. Stress tests are small fracturing tests that use water and are used in the coal and adjacent rock layers to measure the in situ stress.	Pre activity characterisation/ early stage real time monitoring.	A high level of confidence can be achieved with mini-frac tests as a series of tests are undertaken to ensure repeatability. Usually undertaken ahead of each well stimulation program as rock characteristics can vary even over a short distance. Fracture extension pressure and efficiency are estimated within 10 to 20 percent of values for main fracture. Minimum stress is estimated within a few MPa of its true value. Permeability is estimated within 50% of its true value. In situ stress tests can measure minimum stress to within 1 or 2 MPa and 2nd horizontal stress to within 20 or 30% or its true value.	(Bale, Fossen, Berg, Mjelde, & Kui, 2008; Jeffrey, 2012) (US EPA, 2004) (Economides & Martin, 2007)
Leakoff tests and extended leakoff tests	Used during drilling stage to estimate in situ stress. Fluid is injected into wellbore to form fracture and pressure decline is monitored.	Pre activity characterisation/early stage real time monitoring.	Minimum stress is estimated to within a few MPa of its true value. Confidence similar to mini-frac.	(Jeffrey, 2012) (Moos, 2006)
Tiltmeters	Information on fracture orientation and volume. Senses rock deformation and tilt generated by fracture opening using an array of tiltmeters located in shallow off-set wells (~10 m) or deep offset well at comparable depth to fracture. Downhole tiltmeters can determine fracture depth; surface tiltmeters cannot. Tiltmeters must be within a fracture diameter of the fracture to infer size information.	Real time stimulation monitoring (5 min delay).	Resolution better than one nanoradian. Background noise and drift can be problematic in certain locations; can assess fracture height in proximity of well – cannot measure how far fracture extends or height further from well. Interpretation assumes one set of rock properties.	(Commonwealth of Australia, 2014; Cook, 2013; King, 2012; Taurus Reservoir Solutions, 2008)

Micro seismic sensors	Measures fracture orientation, location, height and length. Triangulates 'sound' of fracturing. Microseismic signal measured by an array of accelerometers/ geophones located in an offset monitoring well approximately 100m away at comparable depth. Determines a 'box' fracture is contained within, but upper limit only. Generally used on first few fracs.to optimise fracture program design. Expensive to undertake. Requires a deep offset well.	Pre activity characterisation/ real time stimulation monitoring (< 5 min delay).	Accuracies of 15m are cited, using 1-3 listening arrays. Design mostly to 175ºC; problematic in deeper (non CSG) wells > 200^{o}C; can assess fracture height in proximity of well – cannot measure how far fracture extends or height further from well. Interpretation assumes single rock properties.	(Carter, 2013; Commonwealth of Australia, 2014; Cook, 2013; King, 2012; Taurus Reservoir Solutions, 2008)
Fibre-optic sensors	Placed down the well casing to measure temperature, pressure and sound to provide real-time information on the location of a fracture within a well. Not routinely used in CSG production wells.	Real-time stimulation monitoring. Less commonly used in CSG.	More accurate or reliable than electronic gauges, particularly in high pressure or high temperature conditions. Distributed measurements allow location of fractures along horizontal well.	(Pitkin et. al., 2012, cited in Cook, 2013)
Pressure sensors, flow rate meters, fluid density meters (for proppant in slurry)	Connected to the production casing and outer casings to monitor downhole pressures and well integrity. Injection pressure measured at surface and sometimes downhole. Indirect measure of fracture height. Show features correlating with fracture initiation, propagation, height growth, containment and closure.	Real time stimulation monitoring or post fracture.	Downhole pressure is of highest value in interpreting fracture growth. Annulus pressure is essential in monitoring ongoing integrity of the well as the stimulation proceeds. Accuracy is very high. Pressure and injection rate are always collected during the stimulation and allow history matching of treatment after the fracture is completed.	
Photography Acoustic image logs Resistivity image logs	Downhole, side looking cameras to provide images of fracture growth. Limited to low pressure and clear fluid situations. Acoustic logs image the wellbore using sound waves. Resistivity image logs use pad that sense resistivity changes as they move along the wellbore.	Real-time stimulation and post fracture monitoring.	Only view surface of an exposed wellbore. Work through fluid that is not clear. Resolve features to a few mm in size. Resistivity logs can image features to 1 mm size.	(Cook, 2013; King, 2012)
Chemical tracers in fracture fluid	Added to hydraulic fracture fluid to improve understanding of fracture fluid loss and flowback efficiency.	Post fracture monitoring. Experimental and infrequently used in CSG.	Fluorescent tracers can be added to the injected fluid and the flow back volume and period of run determined through simple mass balance calculations. Requires precision dosing over duration of stimulation. Can be used to verify leakage into adjacent aquifers.	(Cook, 2013)

Temperature and production (flow) logging	After a hydraulic fracture, logs of temperature and flow along the well provide information related to fracture location and hence growth (and also fracture height for vertical wells).	Post fracture monitoring.	Temperature surveys can assess fracture height in proximity of well – cannot measure how far fracture extends or height further from well.	(Commonwealth of Australia, 2014; Cook, 2013)
Proppant Tagging	Radioactive isotopes tagged to the proppant can be analysed to locate where different stages of the proppant go and hence the fracture location. Can measure fracture height in vertical wells and indirectly fracture height and length. Materials that are not radioactive exist that are then activated by the logging tool and give off radiation for a few seconds. These allow a safer method to tag proppant.	Post fracture monitoring. Less commonly used in CSG.	Investigation to a few inches; can assess fracture height in proximity of well – cannot measure how far fracture extends or height further from well.	(Commonwealth of Australia, 2014; Cook, 2013; King, 2012)
Pressure build up, production and interference tests	Analysis of transient pressure response of the reservoir can be used to measure fracture conductive length. Fracture geometry is inferred from build up and pressure tests. Build up tests can be run in CSG wells but often the build up may be too low to bring water to the surface, limiting the ability to obtain a large radius of interest. The test improves if run over a long time period.	Post production monitoring	Analysis of transient pressure response measures conductive length which is often very different from physical length. Therefore may not compare well to fracture model estimates which predict physical length. Build up tests can achieve similar reliability to mini-frac, given enough time.	(King, 2012)

5 OBSERVATIONS AND CONCLUSION

5.1 OBSERVATIONS

Prior to the Review, advice was sought by the NSW Government on the likelihood of fracture stimulation being undertaken in NSW, and expert advice was commissioned by the Office of the Chief Scientist and Engineer (Cook, 2012; Jeffrey, 2012; Pinczewski, 2012). Consistent with work subsequently commissioned in the Review, key findings were that the decision to deploy fracture stimulation will be subject to cost-benefit analyses, key factors being coal permeability, other basin characteristics (water, pressure and stress) and emerging technologies.

Available data suggests that around 8% of operating CSG wells drilled in Australia (approximately 4,200 to date), have been subject to fracture stimulation. Cook suggests that fracture stimulation is more likely to be used in the Sydney and Gunnedah Basins (where the Permian coals are relatively impermeable), and less likely in the Surat and Clarence - Moreton Basins (where the Jurassic coals are quite permeable) (Cook, 2012). However, Pinczewski makes the point that significant technological advances may significantly reduce the need to use fracture stimulation (Pinczewski, 2012).

Projections on the likelihood of fracture stimulation being deployed in the future vary but to date has been put as high as 40% (Klan, 2014; Pinczewski, 2012). However, these projections are subject to a range of influences. Site and project variables will play a role in decision making as will the life cycle of basins and specific sites as it is in the interest of both companies (returns) and government (royalties) to optimise the extraction of the full available resource and therefore stimulation may be deployed toward the end of well-life to facilitate this. The market price of gas will have a bearing – for example, relatively uneconomic (difficult to extract or extract without stimulation) reserves may become more attractive in a higher price market. Finally, the cost, maturity, scale of application, familiarity and level of confidence in emerging technologies by companies is also an important factor in their take up by companies and acceptance by regulators.

As geology is heterogeneous and complex, characterisation of individual basins and project sites is essential. Past work has given us a good understanding of the stratigraphy and depositional history of the sedimentary basins in New South Wales (Ward & Kelly, 2013). However, smaller-scale structural features, such as individual faults and dykes, may only be identified when activities to characterise it are undertaken. Specific knowledge gaps include in-situ stress characterisation; stress dependence of seam properties; dewatering characteristics and fracture propagation (Pinczewski, 2013b).

This characterisation must be continuously updated as new information emerges, informing both broader developments as well as specific fracture stimulation activities. This is collected through activities such as drilling, core sampling, in-situ hydraulic conductivity measurements, and geophysical mapping for particular projects, but the results are not integrated or readily (publicly) available (Drummond, 2013; Ward & Kelly, 2013). Further, a more complete characterisation will only emerge under the stress of production conditions (Pinczewski, 2013a; Ward & Kelly, 2013). This is due to limited data available at exploration and even the start of production.

A range of monitoring techniques can be deployed before, during and after fracture stimulation. The hydraulic head and levels of aquifers, as well as qualities and quantities of water injected, flow back and produced water can be monitored to help inform facture behaviour. As part of this, the way pressure declines helps inform fracture propagation estimates.

There is a need to close the loop between data captured before and during a fracture into the planning, assumptions and modelling processes for future activities. This reinforces the need for a data repository as recommended in the Initial Report Recommendation 2 (CSE, 2013). The data repository needs to be specifically aimed at providing information for design activities of the stimulation engineers and may not be particularly informative to the general public.

However, it is equally important to recognise modelling limitations, particularly in green-field sites, and to constantly test the adequacy of assumptions. As noted by Ward and Kelly, "*Modelling is only as good as the assumptions and the data fed into it. It must justify assumptions and/or use multiple models"* (Ward & Kelly, 2013).

Even with a good understanding of geological systems, modelling always has uncertainties, therefore planning needs to account for surrounding, and adjacent wells and development. This is illustrated by Directives issued by the Alberta energy regulator (No. 27 in 2006, overtaken by No 83 in 2013) regulating fracturing in shallow depths of less than 200m, directed at protecting groundwater and water bores during stimulation. Following a commissioned expert review, the 2013 Directive revised the limits for initiating stimulation (for hydraulic fracturing being within a zone 200m horizontally from the surface location of a water well and 100 m vertically from its total depth; the figures being 200m and 50m respectively in the case of N_2).

In a landscape subject to continuous and rapid change, it is important that emerging knowledge from practice and research on both risks and technologies is disseminated and able to be incorporated into the regulatory framework.

5.2 CONCLUSION

Drilling and fracture stimulation techniques and technologies are continuously evolving. Approaches for the characterisation of heterogeneous coals and basins, as well as for subsurface modelling and monitoring are also continuously improving. There are a range of tools and capabilities available to manage fracture stimulation activities well.

This emerging knowledge should inform both industry practice and the regulatory framework.

At issue is whether this knowledge is being used regularly, appropriately and effectively and whether the legislative and regulatory framework encourages (or requires) the optimal use of the technologies for fracture stimulation activities. The information represents an opportunity to inform future design and hence reduce potential risk of aquifer interception or loss of containment.

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APPENDICES

APPENDIX 1 – SEISMICITY, SUBSIDENCE AND WATER USE

Over the course of the Review, information papers prepared or commissioned have directly addressed issues raised by stakeholders, including seismicity, subsidence and water use. Environmental risks associated with these issues are explored in the paper CSE Risks (2014a).

Seismicity

Seismicity and induced earthquakes were specifically explored by Gibson and Sandiford (2013) and Drummond (2013) for the Review. Gibson and Sandiford (2013) note that the shallower sedimentary rocks where CSG operations are conducted in Australia are weaker and support lower stress, limiting the magnitude of earthquakes that occur within them; and hydraulic fracturing, while having high flow rates and inducing micro-seismic events, is of short duration. Both authors place induced seismicity from hydraulic fracturing as typically small- in the range of magnitude M_L of <0 and are only detected with sensitive equipment.

Reactivation of existing faults during fracture stimulation are also likely to be small (Drummond, 2013) and may follow combined use of directional drilling and stimulation, although this can be managed via careful monitoring, control of fluid injection and well placement to appropriately space the distance between fault and well (Carter, 2013). Drummond further notes that an analysis of coal seam wells and earthquakes in NSW found no link between earthquakes recorded by the Australian National Seismograph Network (ANSN) and coal seam gas activities. Nor has there been any detection of seismicity induced by the withdrawal of fluids in NSW. It should be born in mind that coal seams are saturated and the introduction of more water through hydraulic fracturing may not significantly alter the stress field whereas dry shale could be in elevated stress regime and a hydraulic fracture operation could relieve this stress.

In the United States (US) there has been a recent increase in the number of perceptible, human induced seismic events, in particular in Ohio and Oklahoma, but these events are associated with the disposal of produced water from shale gas operations into deep saline aquifers predominant across the US.

In 2011 the United Kingdom (UK) Parliament commissioned a study into earthquakes following observed events in northwest shale exploration in England where fluid was injected directly into a known fault and held under pressure. The report concluded that the events were related to fracture stimulation (The Royal Society & The Royal Academy of Engineering, 2013). However the study considered the risk of damaging induced earthquakes was low and it was reasonable to resume stimulation activities with additional safeguards regarding seismic monitoring and operating procedures, which has occurred (Commonwealth of Australia, 2014; Cook, 2012).

Both Gibson and Sandiford (2013) and Drummond (2013) conclude that seismicity induced by waste water re-injection is of greater significance than hydraulic fracturing. This was reiterated in a 2013 report of seismicity risks of shale extraction by the US National Research Council (Gore & Davies, 2013). Reports and case studies reviewed by the authors place the magnitude up to 5.0; events found to range up to 5-8 kilometres from a well and occurring years after the start of operations.

The National Harmonised Regulatory Framework for Coal Seam Gas from the Standing Council on Energy and Resources found that "*The use of reinjection as a means of disposal* *of waste water and brine into suitable underground systems is a method that has not been widely considered in Australia. Governments should evaluate international leading practices for application in Australia"* (SCER, 2013).

The Queensland *Coal Seam Gas Water Management Policy 2012* (available at https://www.ehp.qld.gov.au/management/non-mining/documents/csg-water-management-policy.pdf) prioritises beneficial use of CSG water, but allows (under permit) reinjection, subject to steps being taken to minimise the volume for disposal and undertaking risk assessment and management plans. Permits have been issued (requirements developed with regard to the US EPA hazardous waste injection well criteria - see http://water.epa.gov/type/groundwater/uic/).

Under the NSW Code of Practice for Fracture Stimulation (2012) (currently under review by the NSW Office of Coal Seam Gas), Fracture Stimulation Management Plans are a requirement prior to any activities being undertaken and include a (mandatory) requirement for risk assessment to include assessment of induced seismicity (S 4.2(d)(x)). In addition, any reinjection of produced water requires approval (by the appropriate planning authority) having regard to the NSW Aquifer Interference Policy (2012).

Subsidence

The issue of subsidence causes and risks was specifically explored by Pineda and Sheng (2013) for the Review; and subsidence monitoring by the same authors, Lemon, Spies, Tickle, and Dawson (2013) and McClusky and Tregoning (2013).

The potential for subsidence affects arising from CSG activities is primarily related to dewatering i.e. compression of the coal seam or other overlying strata following reduction in the pore fluid pressure – and not fracture stimulation, although (Pineda & Sheng, 2013) note fracture stimulation may impact on the strength of adjacent strata. Under the NSW Code of Practice for Fracture Stimulation (2012) which is currently under review, Fracture Stimulation Management Plans are a requirement and include a (mandatory) requirement for risk assessments to include assessment of induced subsidence (S 4.2(d)(xi))

All authors point to the need for baseline and ongoing monitoring programs to understand and manage any impacts, including comparisons of vertical and horizontal wells (Lemon et al., 2013; McClusky & Tregoning, 2013; Pineda & Sheng, 2013). Available information focuses primarily on subsidence arising from mining and conventional petroleum. Noting it has received minimal attention in shale operations, Katzenstein using Interferometric Synthetic Aperture Radar (InSAR) identified subsidence of several centimetres following over two decades of extraction in the major producing basins in Colorado and New Mexico (Katzenstein, 2012).

Currently the only publically available estimates of potential subsidence from CSG extraction in Australia relate to Queensland developments (Lemon et al., 2013). Recommendation 3 of the Initial Report (CSE, 2013) recommended that from 2013 onwards, an annual whole-of-State subsidence map be produced so that the State's patterns can be traced for the purpose of understanding and addressing any significant cumulative subsidence.

Water use

Two broad categories of issues have been raised during the Review in relation to water, being produced water and the amount of water used for hydraulic fracturing.

The issue of produced water in CSG has been explored in numerous reports including Khan and Kordek (2014) and Gore and Davies (2013) for the Review. In addition, the Australian Council of Learned Academies (ACOLA) published a report by Cook, Beck, Brereton, Clark, Fisher, Kentish, Toomey, and Williams (2013) which focuses on shale gas extraction, but raises issues relevant to CSG. Environmental risks associated with produced water are explored in the paper CSE Risks (2014a).

There are significant differences between CSG and shale gas extraction in terms of water use for hydraulic fracturing. CSG extraction is a net producer of water, whilst shale gas extraction consumes far more water than it produces. In CSG extraction in the United States, the quantity of water used in fracture stimulation has been estimated between 0.2ML per well (US EPA, 2004, cited in Cook et al., 2013) and 1ML per well (Campin, D, personal communications, 29 September 2014). This initial input is significantly less than that required for shale, which has been estimated between 15 – 25ML per well (Campin, D, personal communications, 29 September 2014). However, stimulation of Cooper Basin shales (South Australia) has been as high as 45ML per well (similar to parts of British Columbia), although the flowback water is good quality and can be recycled (D. Campin, personal communication, 28 September 2014).

APPENDIX 2 – VERTICAL & LATERAL WELLS

Well design and arrangement will be determined by the resource – the depth and size of a reservoir; basin and site characteristics including coal type; regulatory requirements or incentives and cost-benefit considerations.

The characteristics of sites that may favour vertical or lateral (including horizontal) drilling approaches are summarised at Table A2.1. However, the two may be used in conjunction e.g. a number of lateral wells can be run off a single vertical, or drilled to intersect with a vertical. Well types can also be used for different purposes e.g. vertical wells may be drilled as part of an exploration program to understand sub-surface characteristics. Similarly, while directional drilling is predominantly used for production purposes, it may be used in the exploration phase to gain an understanding of its efficacy and value in specific site conditions.

Table A2.1: Factors influencing vertical and lateral well types

	Vertical wells (1)	Lateral wells (2)	Comment
Geological factors			
Depth of seam	Unlimited	Less viable in shallow context as limited by rock strength (will crumble under pressure) NSW- minimum 170m depth; typically 250-1200m Queensland working at 1000m	Lateral wells require specialist equipment for shallow sites that can work at slant/ angle
Thickness of seam	Can target seams of > 1m Thinner stacked coals with varying lithology interspersed between reservoir rock	Can drill and accurately visualise in narrow seams but 2m minimum is approximate cut-off for economically viable drilling. Thick continuous seams. Possible to drill multiple laterals in 'stacked' seams, but $ will determine viability	Advanced drilling visualisation capabilities enable drillers to visualise in seams as small as 20-30cm, but not economically viable to drill
Age/rank of seam	Not a consideration	Not a consideration	
Porosity/ permeability	High permeability in the form of strong cleating is required for vertical wells. It is preferred that the cleating be open in all directions, interconnecting throughout the reservoir	Good permeability in lateral wells should have strong cleating in at least one direction	
Orientation of cleating	Orientation may be relatively equal in all directions	Orientation should have one dominant direction	Advantage of directional drilling- can design to cut across dominant pattern
Seam undulation/ flatness	Not a consideration	Flat or gently dipping seams preferred Direction of dip will influence where well head is located	It is preferable to have the direction of gas and water flow underground to be sloped down towards the well
Surface factors			
Number wells & size of well pad – size and access issues	Smaller pads but larger numbers	Multiple wells e.g. 3-10 have been run off single pads in NSW but pad larger – need space to access multiple well heads	The same size and rig can be used for both types of well- rig determines pad size and spacing
Number of trucks and people	Dependent on size and rig type	Dependent on size and rig type	

Time/ well (in and out of site)	3-4 days	5-6 days deviated (50^0 - 60^0) 7-10 days horizontal	Will be influenced by: Rig e.g. big 'fit for purpose' rigs vs adapted smaller (from mineral extraction operations) Bit type and lithology Lateral well length Lateral well type e.g. 'motherbore' from which horizontal component is 'kicked out' which takes longer or drilled in-seam continuously to total depth
Cost	Generally cost less, but will usually have smaller drainage area (of gas)	Generally cost more (larger more complex rigs), but offset by larger drainage area (of gas)	
Training and Expertise			
Requirements	Well site geologists with experience reading logs and describing geological samples	Service companies with directional drilling experience and specialised tools to direct drilling Site geologists with 'geosteering' skills to remain within target and interpret data Rig supervisor with directional drilling experience	Lateral operations more complex and require commensurate expertise

(1) Vertical wells are true vertical or may be deviated (drilled directionally away from a true vertical plane) but are less than horizontal.

(2) Lateral wells are drilled from a vertical to horizontal or near-horizontal plane

(Halliburton, personal communications, 24 September 2014; Santos, personal communications, 23 and 29 September 2014; Schlumberger, personal communications,12 September 2014)