Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia, 2018

Santos submission, March 2018

Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia 2017

Santos welcomes the opportunity to provide this written submission to the Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia 2017.

We note the inquiry is to undertake an assessment and report on the potential impacts arising from the implementation of hydraulic fracture stimulation (fracking) on the onshore environment of Western Australia (WA), outside of the Perth metropolitan, Peel and South-West regions, and will:

- Identify environmental, health, agricultural, heritage and community impacts associated with the process of hydraulic fracture stimulation in Western Australia, noting that impacts may vary in accordance with the location of the activity;
- Use credible scientific and historical evidence to assess the level of risk associated with identified impacts;
- Describe regulatory mechanisms that may be employed to mitigate or minimise risks to an acceptable level, where appropriate;
- Recommend a scientific approach to regulating hydraulic fracture stimulation; and

With all of Santos' oil and gas interests in WA sourced from offshore fields, the company is not in a position to provide WA-specific data relevant to the Inquiry.

However, with more than 60 years of finding, developing and producing natural gas throughout Australia, Santos is better placed than most to help address the issues being considered by the Inquiry.

Indeed, Santos has hydraulically fractured more wells in Australia than any other oil and gas operator. Whilst most have been in tight formations, the principles, practices and systems for safe and sustainable hydraulic fracturing activities in shale resources are the same.

Santos has hydraulically stimulated over 1,400 wells in South Australia (SA), Queensland and the Northern Territory (NT), involving more than 4,400 individual hydraulic stimulation stages.

Santos also has a long and positive track record of working responsibly alongside local communities and other users of the land in a fair, open and cooperative manner.

Who is Santos?

Santos is one of the leading independent oil and gas producers in the Asia-Pacific region, supplying the energy needs of homes, businesses and major industries across Australia and Asia.

With its origins in the Cooper Basin, Santos has one of the largest exploration and production acreages in Australia and extensive infrastructure, and is committed to supplying the domestic markets, unlocking resources and driving value and performance.

Underpinned by a portfolio of high-quality liquefied natural gas (LNG), pipeline gas and oil assets, Santos seeks to deliver long-term value to shareholders.

Santos' foundations are based on safe, sustainable operations and working together with our shareholders, host communities, governments and business partners.

Santos has a significant gas business in WA, producing exclusively for the domestic market through its offshore John Brookes, Spar and Reindeer fields using the company's processing capacity at Varanus Island and Devil Creek.

Santos is also an active explorer in offshore WA, with discoveries at Zola-Bianchi, Winchester and Spartan in the Carnarvon Basin, and Crown, Lasseter and Burnside in the Browse Basin.

Hydraulic Fracturing

Hydraulic fracturing is not new to Santos, nor the industry. The practice was first employed by Santos in the late 1960s, and has been used consistently since the early 1980s to enhance oil and gas recovery

Last decade, the combination of technological advances in hydraulic fracturing and directional/ horizontal drilling unlocked unconventional gas in the United States (US) that saw shale gas jump from 1% of supply in 2000 to 25% by 2011 and 50% by 2015. Hydraulic fractured wells provided more than two-thirds of US natural gas production in 2015.

The so-called ‘shale gale’ has transformed the US economy, sending carbon emissions plunging (with gas replacing coal-fired electricity), stimulating jobs and local economies, and turning the nation from an energy importer to one that is not only self-sufficient but also a major exporter. It has also driven down domestic gas prices and stimulated new manufacturing.

In Alberta, Canada, hydraulic fracturing has been used to safely stimulate over 180,000 wells and over 10,000 wells have been drilled using horizontal drilling technology. Since 2013, over 80% of all producing oil and gas wells use horizontal drilling techniques.

1.0 Shale Gas

Shale gas is primarily methane trapped within shale rock layers at depths greater than about 1,500 metres (m) (CSIRO, 2015). Shale gas occurs within rock formations, under high confining pressure, which have low porosity (proportion of volume consisting of pore spaces) and negligible permeability (ability to transmit a fluid through connecting pore spaces). These properties restrict the natural flow of gas within or from the shale. Hydraulic fracturing is (always) used in shale gas wells to increase the flow of gas from the shale reservoir (CSIRO, 2015).

1.1 Natural shale gas formation

Shales were originally deposited as laterally extensive, organic-rich muds and silts in anoxic or sub-oxic environments on a sea or lake floor. On burial, and under conditions of increasing pressure and temperature, the organic material is transformed into organic derivatives (‘kerogen’) and, under increasing temperature and pressure, hydrocarbons are generated. A first phase of oil generation and expulsion may be succeeded at higher temperatures by gas generation resulting from the ‘cracking’ of long chain hydrocarbons and kerogen.

Key features of shale gas and shale oil reservoir rocks include:

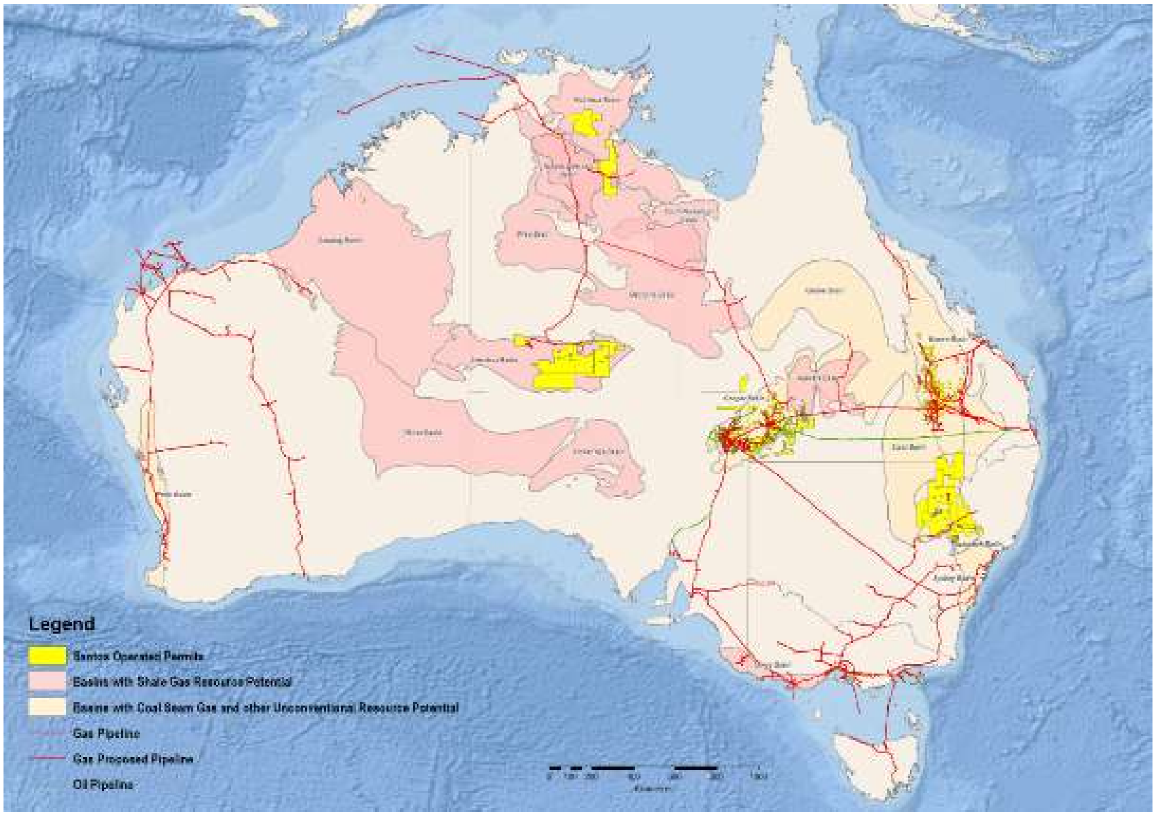
- Diverse, often interbedded, fine-grained rock types such as siltstone, limestone, dolomite, mudstone; rarely true shale (defined in its original stratigraphic sense as ‘fissile mudrock’).
- Significant amount of thermally matured organic matter.
- Low permeability (less than 0.1millidarcy (mD)).
- Tens to hundreds of metres thick.
- Significant fraction of generated hydrocarbons retained within microscopic pores and fractures in the source rock or in adjacent low permeability layers.

Shale gas exploitation targets these un-expelled hydrocarbons.

1.1.1 Shale gas resources in Australia

Australia comprises a number of sedimentary basins, particularly in northern, central and western Australia, which are prospective for shale gas, based on the abundance of shale, their likely maturity and their total organic carbon content (ACOLA, 2013). Indicative shale gas resources and Santos' petroleum interests across Australia are shown in Figure 1.

Figure 1 Shale gas resources and Santos petroleum interests in Australia



Source: (Santos, 2017)

Although Australia has potentially vast resources of shale gas, the industry is largely in exploration phase (CSIRO, 2015).

1.1.2 Shale gas composition

In shale gas, like all natural gas, the composition gas can vary depending on the source material for the hydrocarbons, burial conditions (temperature and pressure), sediment composition and other geological influences such as volcanic activity.

Natural gas can contain variable and trace amounts of:

- Non-hydrocarbon inert components such as carbon dioxide, nitrogen, helium, argon and sulphur compounds such as hydrogen sulfides, mercaptans (methanethiol) and alkyl sulphides
- Naturally occurring radioactive materials (NORM) (e.g. radium, radon, thorium)
- Heavy metals such as mercury, antimony, arsenic, beryllium, cadmium, cobalt, copper, lead, nickel, selenium, vanadium and zinc
- Aromatic hydrocarbons (benzene, toluene, ethyl-benzene and xylene (BTEX) and polycyclic aromatic hydrocarbons (PAH) (IESC, 2014).

1.2 Production of shale gas

Shale gas production typically uses horizontal drilling and hydraulic fracturing techniques to release gas trapped in shale formations due to its low permeability (US Department of Energy, 2013). Both horizontal drilling and hydraulic fracturing are among the practices that have become more widely used over the past two decades to enable access to vast new natural gas resources contained in shale deposits across the US (Kargbo, Willhelm & Campbell, 2010), (Mooney, 2011). Hydraulic fracturing is also used, within horizontal and vertical well bores, in the renewable (geothermal) energy industry and to increase the flow rate of groundwater supply bores (APPEA, 2016)

Horizontal drilling and hydraulic fracturing are part of a broader development cycle. Generally, commercial development of a shale gas resource occurs incrementally. The development cycle for a prospective area includes exploration, appraisal, production well and infrastructure construction, production operations, and then decommissioning. Rehabilitation occurs both post development (areas not required for operations) and then post operations.

This section provides an introduction to the development cycle for shale gas, including exploration and appraisal, well construction, hydraulic fracturing and rehabilitation.

1.2.1 Exploration and appraisal

Exploration involves the search for a particular set of geological conditions likely to result in natural gas resources that can be economically extracted. It begins with a review of published materials and geophysical surveys to identify locations for exploratory drilling that best represent the geological formation(s) of interest within known constraints such as tenure boundaries, topography and environmental sensitivities.

Further geological and/or geophysical surveys such as seismic surveys are conducted to characterise subsurface geology and structural features such as depth, inclination, orientation and faults within the target shale. Seismic surveys are shown in Figure 2.

Figure 2 Examples of seismic survey

Exploration core holes are then drilled to collect shale and rock samples for testing. At the end of exploration phase, core holes may be decommissioned or converted into wells if field development progresses into appraisal and production phases.

The hydraulic fracturing and testing of the prospective interval will be critical in determining the commercial potential of a play (shale gas development opportunity). In the exploration phase, hydraulic fracturing and testing may be conducted in a vertical or horizontal well. Gas produced during the exploration phase is collected and flared as pipeline infrastructure is not normally accessible to provide a transport route.

With positive indications from testing, the shale play may move into the appraisal and development phases, while exploration activity will continue to gather information to assess the broader regional prospectivity.

Where testing confirms that a shale formation has the potential to produce gas, appraisal wells are drilled to quantify the size and nature of the gas resource. The appraisal process is a pilot test i.e. a small scale trial comprising production wells with supporting gas and waste management facilities installed. Gas produced during the appraisal phase is normally flared as pipeline infrastructure is not normally accessible to provide a transport route.

From the appraisal phase, operators aim to get an understanding of the production profile that can be expected from newly drilled and hydraulic stimulated wells in future (i.e. production rate with time and total production volume over the life of the well). This information is primarily derived from extended production tests (e.g. 90 day or longer gas flows) conducted during the appraisal phase.

Well productivity information is required to optimally size the production facilities and processes, as well as provide data used in defining optimum downhole well spacing. The maximum number of wells per well lease is a function of formation target depth and the downhole well spacing; this subsequently dictates the number, frequency and size of the well lease at the surface.

Information gathered on gas composition is used to identify appropriate materials for construction of wells and process facilities, as well as the processing steps required to refine and transport the gas for sale to market.

Operators will form an optimised well field concept and fracture stimulation designs during the appraisal phase, but this will be continually optimised throughout the development phase as more information on geology and flow results are obtained.

If the appraisal process indicates that commercial quantities of gas can be produced economically, an optimal development scenario for full scale production can be planned and designed using information gathered during exploration and appraisal stages, including gas quality, volumes and flow rates.

1.2.2 Well construction

Drilling occurs after petroleum engineers and geologists believe economical hydrocarbon reserves may be found and the project is sanctioned. The actual drilling location is selected based on proximity to the subsurface target location and environmental and cultural heritage assessments are undertaken in consultation with relevant stakeholders. Following assessment and consultation the well lease is prepared for drilling operations.

1.2.2.1 Planning, scouting and assessment

The planning, scouting and assessment process for a new well typically involves:

- Santos and any joint venture participants agreeing on a proposed subsurface target location
- Landholder, traditional owner and stakeholder consultation and notifications undertaken to ensure all parties are aware of possible risks to infrastructure and their operations
- Field location is scouted and the well lease and access location(s) refined to minimise potential impacts associated with ground disturbance and infrastructure development
- Sacred site approvals are requested
- Environmental assessment undertaken using scout data, public and Santos database and GIS information and field inspection where appropriate (e.g. new areas or sites with potential environmental sensitivity)

- External approval for work programs (where required) are obtained
- Specifications/work packages are developed for well lease, access track and associated infrastructure construction
- Drilling program and well design are developed and approved
- Activity Notification is provided to the regulator.

1.2.2.2 Well lease and access roads

The objective of constructing a well lease is to create a stable working platform suitable for safely undertaking drilling, completions and well operations. The lease incorporates safe access and areas for the drilling rig, generators, fuel, chemical, casing and pipe storage, and associated portable buildings. It is also designed for subsequent operations like hydraulic stimulation, and generally incorporates the following standard features:

- A compacted and stable drilling rig hard stand area
- A mud sump for management and disposal of drill cuttings and the recirculation of water into the mud system
- An access road or track with clear entry and exit points for vehicles
- Mobile wastewater treatment systems for the disposal of ablutions waste from well site offices and accommodation
- Water storage tanks or ponds for drilling and/or hydraulic fracturing water and flowback fluid
- Proppant and chemical storage for drilling and/or hydraulic fracturing operations

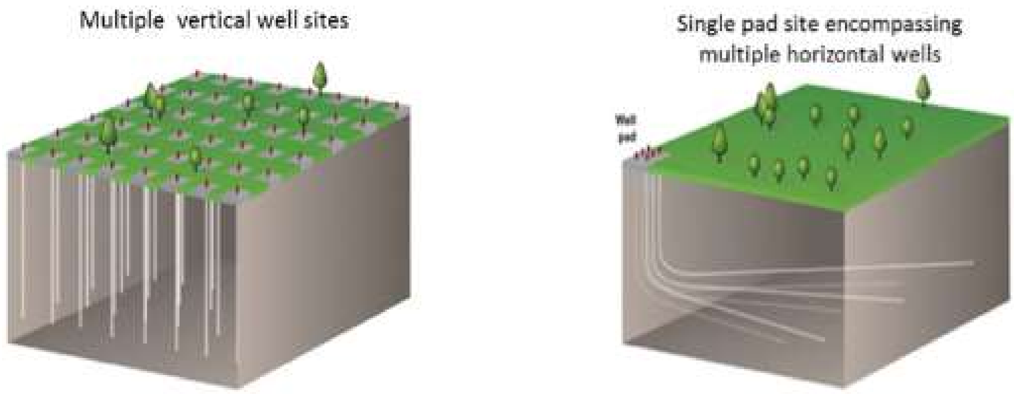
The size and layout of the well lease will vary depending on a number of factors such as the number of wells to be drilled (multi-well pads), the size and type of drilling rig, the number of hydraulic stimulation stages, the program for completion of the well(s) and the surrounding environment.

The lease size required to accommodate an exploratory drill well would be approximately 145 m x 90 m. Whereas, the lease size required to accommodate hydraulic fracturing for a 10 well pad, with 34 stimulation stages per well, is typically in the order of approximately 145 m x 210 m, with additional space required for proppant and water storage. The water storage pad would be approximately 240 m x 120 m to enable 2 x 18 ML double lined above ground ponds to be installed. The proppant and chemical storage pad is expected to be approximately 150 m x 150 m. This example is expected to represent the upper requirement for land disturbance.

The multi-well pads mentioned above are an opportunity to minimise disturbance and movement of equipment due to the ability to drill and complete multiple wells from a single well lease. They typically require a larger initial area, however, the overall disturbance results in a smaller footprint per well. For example, approximately 10 wells can be drilled from a pad area the same size as two discrete single well locations. A schematic illustrating decreased land disturbance of multiple horizontal wells is presented in Figure 3, on the next page.

The well lease area prepared to accommodate necessary drilling and completion equipment and support services for the well will be the same area used for hydraulic fracturing the well. Where practical, Santos will aim to establish well leases with multiple wells where feasible to reduce the number of well leases (and disturbance) required.

Figure 3 Schematic well configurations illustrating decreased land disturbance of multiple horizontal wells



Source: *(Seven Generations Energy)*

Well lease construction methods vary depending upon the land system and soil type on which the well is to be drilled. Typically, topsoil with rootstock and vegetation is cleared and stockpiled for use later in restoration. Material sourced from borrow pits is imported where required to construct the lease pad, access roads and associated infrastructure. Borrow material is watered and rolled to achieve adequate compaction, provide a stable and trafficable surface and reduce dust. The risk of erosion is managed through the well pad design (i.e. surface water run-on and run-off) and engineered management controls. Considerations for siting and constructing well leases and associated infrastructure include:

- Selection of non-sloping well leases is preferable (this minimises the requirements for cut and fill or importation of borrow material to level the site)
- Employment of additional management controls in sensitive areas such as floodplains and proximity watercourses (where required)
- Constructing erosion control measures where appropriate (i.e. diversion banks or berms)
- Capping of sensitive terrain to preserve the underlying soils where required
- Avoiding environmentally sensitive and restricted areas and ensuring compliance with terms of sacred site certification
- Minimising disturbance of native vegetation and fauna habitat.

Due to the extended and often remote nature of drilling, completions and well operations, a temporary camp site is usually required to provide accommodation for drilling, completions and associated support personnel. Camp sites are located within proximity to well leases to minimise travel related risks.

Where possible, existing camp sites are used, however, where new sites are required construction methods are similar to those employed for well leases with the exception that:

- There is more flexibility for locating camp sites as they are not required to be at a specific location, but typically within 10 km of the wellsite
- The level of compaction required to achieve a stable base is less than that required for well leases, as heavy vehicles are less present in these locations.

Camp sites locations are flexible and are typically constructed in areas where disturbance of native vegetation, particularly woody vegetation can be avoided or minimised. Camp location also takes into consideration landholder requirements, such as the potential for noise and dust generation and other operational hazards such as traffic.

Access tracks are required for drilling, hydraulic fracturing and completion operations, and vary depending on the land system and the expected frequency of use and traffic loadings. Access tracks for exploration wells may initially be constructed for temporary use only, compared with those constructed for development wells which are constructed to allow access for the life of the well, which could span 20-40 years. Safety requirements are taken into consideration and define the minimum design standards for road and access tracks. Roads are constructed to withstand heavy and light vehicles associated with the activities. Where further developments or activities are planned, access tracks will be upgraded to reflect the nature of the development and traffic loadings.

1.2.2.3 Drilling

A well is drilled by rotating a drill bit while exerting downward force on the drill pipe. During drilling, fluid is pumped through the inside of the drill string to the drill bit and back up the outside of the drill string to lift drill cuttings out of the hole. The drilling fluid / drill cuttings are then channelled into tanks or pits where the drill cuttings are separated from the drilling fluid, and then drilling fluid is recycled down hole in a continuous process. The well is drilled deeper by adding a length of drill pipe to the drill string. Drilling fluids are also typically recycled onto other wells in a multi-well scenario. Casing, which is concentric steel pipe, is installed into the well and cemented in place to provide the structural integrity and well integrity barriers for the designed life of the well. A typical drilling rig layout, and lease and access roads required for Cooper Basin drilling operations, is shown in Figure 4.

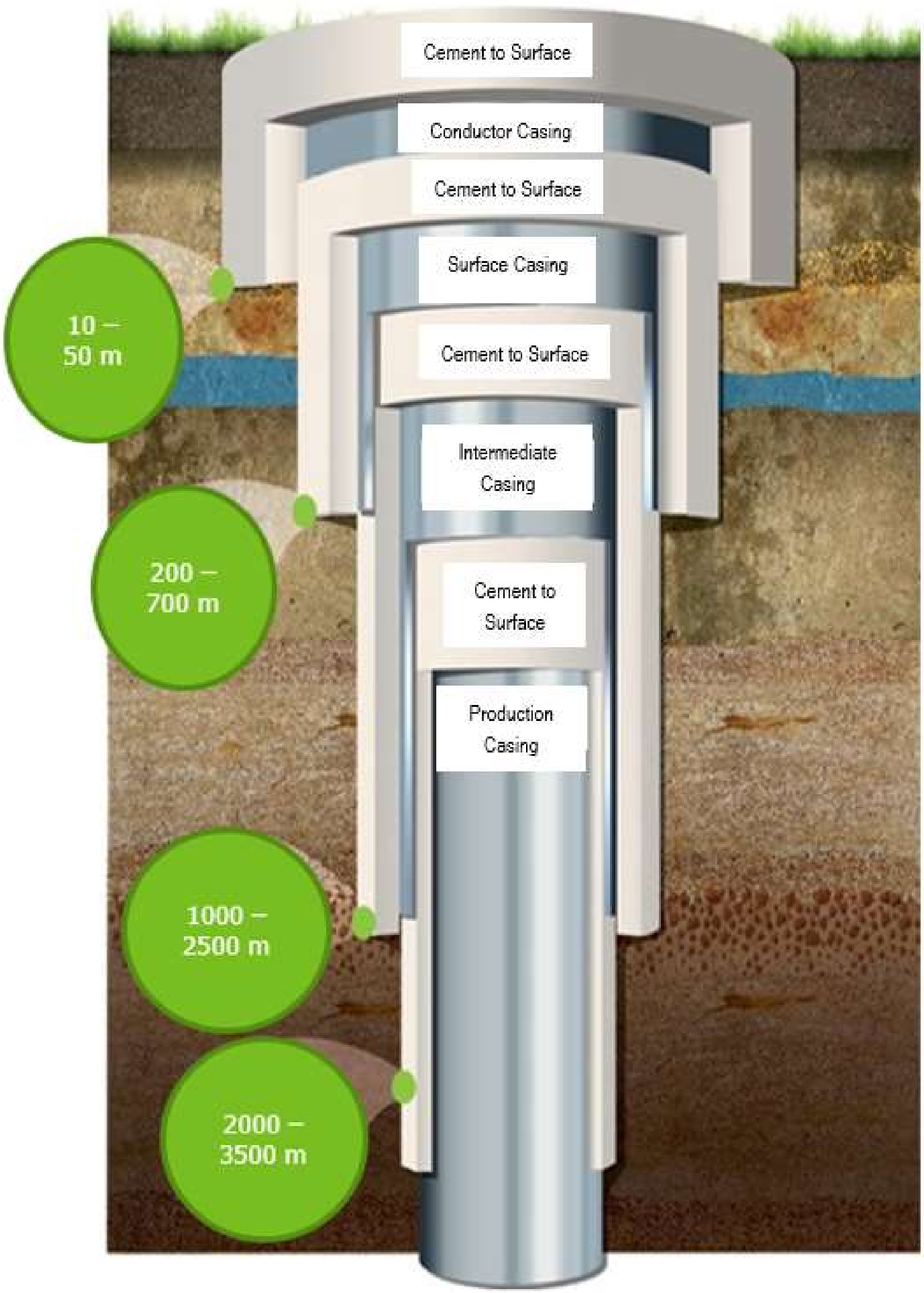
Figure 4 Example of well lease and drilling rig in Cooper Basin (SA)

Wells are drilled to reach the gas formation targets, through a series of hole sections; each hole section serves a specific purpose for well construction and well integrity as outlined below and depicted in Figure 5.

1. The Conductor Hole Section (406 – 508 mm outside diameter (OD)) may be drilled and cased to stabilise the surface sediments from the drilling of subsequent drilling phases (i.e. it prevents the loose soils from caving into the borehole), and is cemented into place to ensure an appropriately robust seal (up to ground level). The conductor casing (406 – 457 mm OD) also serves to isolate aquifers near surface, if present. A conductor casing string is installed as required by design for well construction purposes.

2. The Surface Hole Section (311 - 406 mm OD) is drilled and cased to achieve regulatory requirements for isolating shallow aquifer systems and to stabilise the well for subsequent hole sections. The hole section is drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. The surface casing (244 – 340 mm OD) is cemented in place from bottom to top to ensure effective pressure isolation of shallow aquifers from deeper hydrocarbon bearing zones encountered in subsequent hole sections. Finally, it is pressure tested to simulate well life design specifications. This is represented graphically in Figure 5 below.

Figure 5 Schematic of the hole sections and depth range (True Vertical Depth) expected for a typical shale well. The well is depicted as vertical to more easily illustrate casing and cementing design, however may also be horizontal



Source: *(Santos 2017)*

3. After the surface casing is installed, a Blowout Preventer (BOP) is installed onto the well at surface to provide a second barrier along with the drilling fluid. At the commencement of drilling the next hole section (i.e. only 2-3m of new hole drilled), a Leak Off Test (LOT) or Formation Integrity Test (FIT) is conducted to determine the rock strength. This will ensure the well is drilled without risk of the rock failing due to exerted pressure.
4. The Intermediate Hole Section(s) (216 – 311 mm OD) may be drilled and cased to isolate deeper aquifer systems (if present) and/or to contain pressure that may occur during the subsequent hole section. The hole section is drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. As with the surface casing, the intermediate casing (178 – 244 mm OD) is cemented in place to ensure appropriate well integrity. Finally, it is pressure tested to simulate well life design specifications. An intermediate casing string(s) is installed if required by design for well construction and/or well integrity.
5. The Production Hole Section (152 – 216 mm OD) is drilled to intersect formation targets and is drilled to a depth below the lowest hydrocarbon bearing target. The hole section is typically drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. Logging while Drilling (LWD) may be applied to gather data in real time to gain an understanding of the petrophysical environment.
6. Openhole logging is performed after the production hole section has been drilled and prior to the production casing being run. Wireline logging operations for Santos are undertaken by a number of different industry recognised specialist service companies. Different energy sources are lowered into the well via wireline including density, neutron, acoustic and electrical logging tools. Calculations based on the received signals are undertaken to evaluate the different parameters of the formation such as porosity, permeability, rock type and hydrocarbon saturation. This information is used to ascertain whether the well is economical to run production casing for future production. If the well is not economic, a decision not to run production casing may be made requiring the well to be plugged and decommissioned.
7. After the production hole is drilled and logged, production casing (114 – 152 mm OD) is installed to the total depth of the wellbore and cemented in place. It is pressure tested to simulate well life design specifications. The purpose of the production casing is to provide hydraulic isolation between the hydrocarbon reservoirs and all other overlying formations, to contain the pressurised fluid used to hydraulically stimulate the target zones, and to provide effective wellbore integrity for well production. The high quality steel casing is designed specific for each well.

1.2.2.4 Engineering design

Casing design scenarios are modelled through specialist software to simulate the design loads for collapse, burst and tensile failures, observed during the operational and production phases. The results of this analysis direct the selection of casing grade and weight. All casing is tested by Santos and the contractor using specific Quality Assessment and Quality Control (QA / QC) procedures prior to installation to ensure compliance with the Santos engineering and regulatory specifications.

After each hole section is drilled, the steel casing is cemented in place. The correct composition, volume and placement of cement is the construction aspect that is most important for well integrity. The cement serves two purposes – it provides protection and structural support to the casing while also providing zonal isolation between different formations, including aquifers. The cement and required additives are high quality materials produced specifically for oil and gas operations with the materials selected designed to address the specific conditions of a particular well. Santos and the cementing contractor must ensure the cementing material and equipment is adequate to achieve the well design objectives and ensure effective isolation. Prior to pumping the cement, it must be lab tested against the engineering design and actual downhole conditions such as temperature. The cement is tested using specific QA / QC procedures and includes the following:

- Slurry density
- Thickening time
- Fluid loss control
- Free fluid
- Compressive strength development
- Fluid compatibility (cement, mix fluid, mud)
- Sedimentation control
- Expansion or shrinkage characteristics of the set cement
- Static gel strength development
- Mechanical properties (e.g. Young's modulus, poisson's ratio, elastic/compressibility characteristics).

Cased hole logs can be run inside the cemented casing to validate the quality and integrity of the cement sheath bond to the casing and to the formation. Typically, these logs include:

- Gamma ray - measures naturally occurring gamma radiation to characterise the rock or sediment in a borehole
- Casing collar locator - a magnetic device that detects the casing collars
- Cement bond log - an acoustic device used to measure the properties of the cement sheath and the quality of the cement bond between the casing and the formation.

As mentioned, the cement bond log is an acoustic device that can detect cemented or non-cemented casing. It works by transmitting a sound or vibration signal into the casing, and then recording the amplitude of the arrival signal. Casing that has no or poor quality cement surrounding it (i.e. free pipe) will have large amplitude acoustic signal because the energy remains in the pipe and isn't transmitted to the formation. Casing that has a good cement sheath (fills the annular space between the casing and the formation and effectively couples the two) will have a much smaller acoustic amplitude signal as the energy is absorbed by the formation due to effective acoustically coupling. Santos uses experienced contractors to identify the key features of the cement quality to ensure the integrity of the cement seal for each casing pipe sheath. If cement is not of sufficient height or quality and deemed by the operator to be unsafe for continued operations, hydraulic stimulation will not proceed until it can be effectively remediated.

1.2.3 Hydraulic fracturing

This section describes the hydraulic fracturing and associated activities.

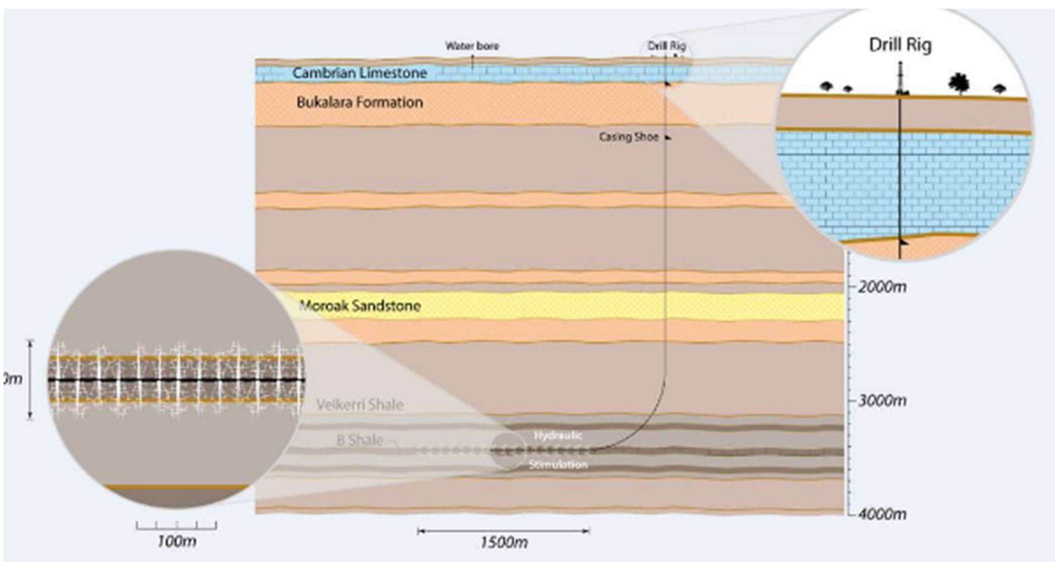
Hydraulic fracturing is a predominantly physical process in which hydraulic pressure is applied to a fluid (oil, gas or water well or bore) to increase the effective permeability of the formation rock. The process creates narrow pathways (fractures) in the shale gas reservoir to improve its ability to transmit gas back to and then out of the well.

It is noted that, unlike coal seam gas, no depressurisation via groundwater extraction is required to produce shale gas. Once the hydraulic stimulation is complete much of the water introduced into the well returns to surface after the introduced pressure is removed. The naturally occurring shale gas flows from the shale, via the enhanced permeable (fracture) zones, to surface of the well.

After pre-fracturing assessment and hydraulic fracturing design, onsite activities include site setup, perforation of the well casing and cement into discrete targeted sections of the cased bore (to access most viable gas bearing shale formation), injection of hydraulic fracturing fluid and flowback of the injected fluid.

A schematic of a typical shale gas bore, including both vertical and horizontal drilling and the fractured sections (extent and location) within the targeted shale unit, is illustrated in Figure 6.

Figure 6 Typical shale gas bore showing vertical and horizontal drilling and hydraulic fracturing targeting shale unit



The process of hydraulic fracturing is detailed below.

1.2.3.1 Pre-fracturing assessment and hydraulic fracturing design

Operators investigate the subsurface conditions, including hydrogeological and mechanical properties of the target and surrounding geological units, to design the hydraulic fracturing program to strategically identify and reduce the possible risks involved (IESC, 2014).

To understand the geological formation and priorities for the hydraulic fracturing program, key aspects of subsurface characterisation (Beckwith, 2010), (New South Wales Trade and Investment Resource and Energy, 2012) include:

- Describing all geological units
- Assessing target formation permeability
- Analysing subsurface distribution of stresses and faults
- Assessing fluid loss characteristics.

The hydraulic fracturing program is designed after the subsurface characterisation is complete. Part of this design is the prediction of fracture growth within the target zone. Specific hydraulic fracture simulation software is used to predict the geometry of fractures, while the orientation is determined from the in situ stress field (IESC, 2014). Typical inputs to numerical models include volume and properties of the fluid and proppant, closure stress, pressures within pores, permeability, mechanical properties and layer geometry.

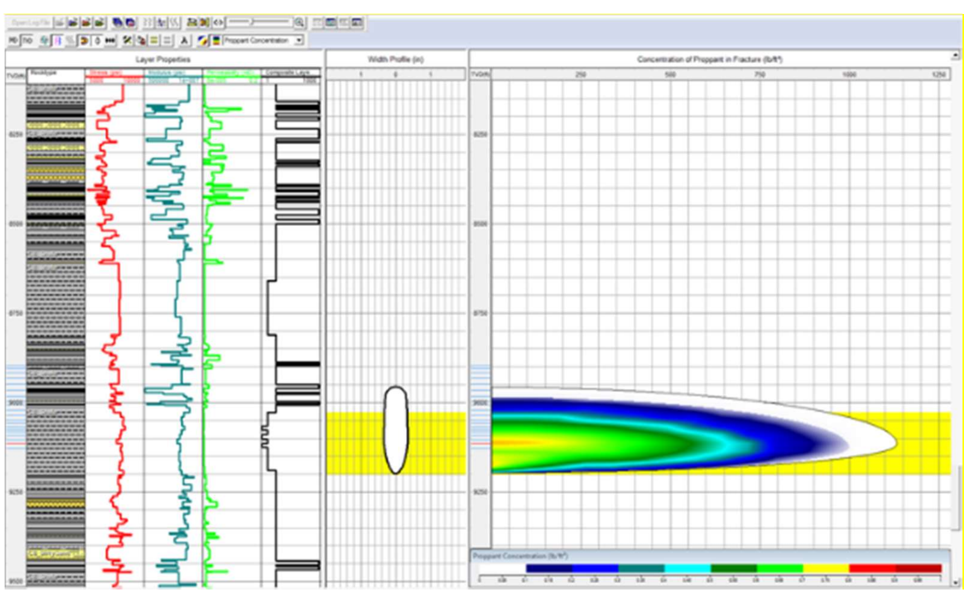
Open hole and cased hole logging provides information required for the hydraulic stimulation design process, including rock stress and lithological parameters. This data is processed using specialist stimulation software to develop an optimal design. The basis of well specific hydraulic fracture design is to create a fracture within the target formation that will produce hydrocarbon through the number of required fractures.

This is achieved by modelling fracture length, fracture conductivity, and fracture height for each created fracture as depicted in Figure 7.

A number of considerations influence the final design for each stimulation treatment, including:

- Depth and thickness of the formation target
- Lithology of formation target and bounding layers
- Minimum and maximum horizontal stress across all layers (target and bounding)
- Thickness of the seals above and below the target reservoir formation
- Porosity and permeability of the formation
- Pore fluid saturations (percentage of formation pore volume occupied by oil, gas or water)
- Pore fluid properties (e.g. Density, water salinity)
- Well performance data, including flow rates, formation pressure and produced fluid properties
- Formation boundaries (as identified from seismic data)
- Bulk rock density, elastic properties and compressibility
- Natural fracture networks
- Stress field analysis to determine the maximum principle stress direction and the minimum principle stress direction.

Figure 7 Modelled output from industry accredited software for Cooper Basin horizontal well shale hydraulic fracture



Source: *(Santos 2014)*

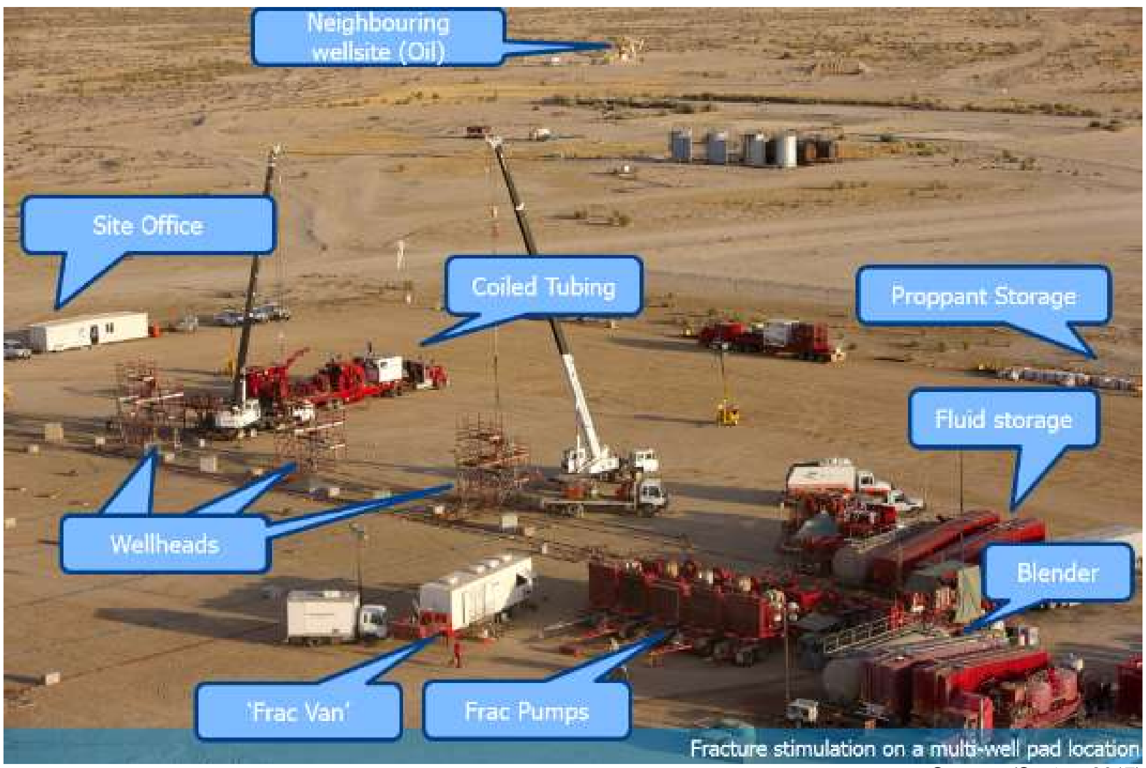
1.2.3.2 Site set up

The well lease provides a stable working platform suitable for safely undertaking hydraulic fracturing operations. The lease area provides adequate space for the hydraulic fracturing vehicles and equipment, generators, fuel and chemical storage, casing and pipe storage and associated portable buildings. The well lease area generally incorporates the following standard features:

- A compacted and stable hard stand area
- An access road or track with clear entry and exit points for vehicles
- Mobile wastewater treatment systems for the disposal of ablutions waste from well site offices and accommodation
- Water storage tanks or ponds for hydraulic fracturing make up water and flowback fluid
- Proppant and chemical storage for drilling and/or hydraulic fracturing operations.

An example of hydraulic fracture set up is shown in Figure 8.

Figure 8 Example hydraulic fracture spread for 3-well pad in Cooper Basin, SA



Source: *(Santos, 2017)*

1.2.3.3 Stimulation

After determining that the well has the required design and well integrity to undergo stimulation and completions, the well is handed over to 'complete' the well and set it up for production. Hydraulic fracture stimulation is not part of the drilling process but is a completion technique applied after the well is drilled. The intent of hydraulic stimulation is to place a highly conductive channel (fracture) into the reservoir to increase the flow capacity of the well. It is a process that has been used in the oil and gas industry since 1947. The Society of Petroleum Engineers (SPE) estimates that over 2.5 million hydraulic stimulation treatments have been undertaken in oil and gas wells worldwide. It has been successfully used on wells in the Cooper Basin for nearly 50 years without a primary barrier breach and is currently performed in many hydrocarbon basins around Australia.

The stimulation process involves pumping water, a specific blend of chemical additives and a propping agent such as sand or ceramic beads down the well at sufficient pressure to create a fracture in the target formation. Proppant keeps the fractures open once the pump pressure is released which thereby improves the productive potential of the well. A fracture created in deep shale reservoirs, will propagate laterally from the well in a vertical plane. An unconventional shale gas well typically takes 7 to 10 days to complete hydraulic stimulation operations, with a hydraulic stimulation fluid flowback period of 3 to 30 days, depending on the reservoir and clean up profile.

Code of Practice

To ensure risks are appropriately managed, Santos adheres to strict regulatory requirements such as the "Code of Practice - For the construction and abandonment of petroleum wells and associated bores in Queensland".

The Code of Practice has the following mandatory requirements:

- During the well design and planning process, petroleum tenure holders must identify any aquifers at risk of being impacted by hydraulic stimulation operations and fluids
- If any such aquifers have been identified, hydraulic stimulation activities must be designed to not impact these aquifers
- Hydraulic stimulation for gas wells requires verification of cement bond quality using appropriate cement evaluation tools
- If the annulus between the production casing and the surface/intermediate casing has not been cemented to the surface, the pressure in the annular space must be monitored and controlled while conducting hydraulic fracture stimulation
- The pressure relief valves on the pump units must be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing and wellhead.

Santos has a long history of demonstrated well integrity during hydraulic fracturing operations. In nearly 50 years of hydraulic fracturing operations on over 1,400 wells, there has never been a loss of the primary barrier during the fracture treatment. The primary barrier during the stimulation phase is generally the production casing, with the secondary barrier being the surface well pressure control. Should the primary barrier fail, a pressure relief valve (PRV) installed to monitor pressure between the primary barrier and surface casing, is triggered to open at a pressure well below the failure point of the surface casing. This ensures that the surface casing is not exposed to pressure above its design specification, and as a result prevents the risk of well failure. Also, programmable pressure triggers (kickouts) on each of the high pressure pumps will physically shutdown each pump (and associated pressure) if a certain trigger pressure is reached. This trigger is below the design specification of the well. If the primary barrier did fail during hydraulic fracturing operations, operations would cease and it would be repaired to meet the design requirements before going forward with completing the well again.

Proppant and Chemicals

Santos has used the following three primary types of perforating in the Cooper Basin.

- Wireline Conveyed Perforating (WCP) – the most widely used perforating technique in the Cooper Basin. As the name suggests, WCP uses wireline to deploy the perforating charge.
- Tubing Conveyed Perforating (TCP) - uses the same technology as conventional wireline perforating but is run using a coiled tubing unit or jointed tubing (not wireline). TCP is the preferred perforating method when operating in underbalance or overbalanced conditions.

- Hydrojetting – uses sand and water jetted through small holes in the bottom hole assembly to create holes in the casing across the target formation – there is no perforating charge. Hydrojetting allows for targeted or pinpoint perforating, creating three to four holes per event or stage.

In shale hydraulic stimulation treatments, water accounts for more than 90% of the mixture and sand accounts for about 5-9%. Chemicals generally account for around 1% of the mixture and assist in carrying and dispersing the sand in the low permeability rock.

In accordance with regulatory requirements, the chemicals additives are often subject to full disclosure. The chemical additives are not specific to the hydraulic fracture stimulation process, having many common household uses such as in swimming pools, toothpaste, baked goods, ice cream, food additives, detergents, cosmetics and soap. The chemicals used provide the following functions:

Viscosity – gelling agents (natural plant based) are added to the water to provide viscosity to enable the proppant material to be transported down the well and into the created fractures.

Friction reduction – to reduce the force required to pump the fluid, making the fluid more slippery and easier to pump at high pressures and high rates required to create the fracture network.

Biocide – added to ensure that there are no microbes or organisms present in the water that will affect the gelling agents and to ensure they will not enter and affect the hydrocarbon reservoir.

Scale and corrosion – scale and corrosion inhibitors are added to prevent deposition of mineral scales and to prevent corrosion of the primary wellbore barrier, the steel casing.

Surface tension – surfactants or surface tension modifiers are added to assist the flowback of fluids from the formation.

Water Management

The source of water for hydraulic stimulation is considered in detail during the initiation phase of a project. Depending on availability and in accordance with applicable regulations, the water is typically sourced from:

- produced water that has flowed back as part of the fracture stimulation process
- produced formation water from gas production facilities
- surface water sources
- groundwater sources such as local boreholes.

Based on operational experience, Santos uses on average 1 ML for constructing a well lease and drilling a well and 1 ML for each fracturing stage. Therefore, for a long horizontal well with 34 fracturing stages, the total volume of water required will be approximately 35ML.

The shale gas industry only uses a small fraction of the total water usage for agricultural, industrial and other purposes. The take of water is also generally only required during the initial drilling and development period with even smaller volumes required for on-going operations, however, new wells are required to replace gas decline over time. Page 105 of the ‘Report of the Independent Inquiry into Hydraulic Fracturing in the Northern Territory’ (Hawke Report, 2014) says: It is important to place the scale of water requirements for hydraulic fracturing in the context of other water uses. Moore (2012) estimated that the water requirement of a shale gas well over a decade was equivalent to that needed to water a single golf course for one month, or to run a 1,000 MW coal-fired power plant for 12 hours.

If a move from the exploration phase to development phase occurs, facilities are set-up to enable the capture and recycling of flowback fluid to the extent feasible, thereby reducing the amount of additional water required for each subsequent hydraulic stimulation operation. This has the potential to reduce the total additional water requirement to less than 18 ML per well. Flowback water (and subsequently process water) can be reused for subsequent fracturing operations if it can be treated to the required standard in an economically viable way.

A considerable volume of the injected stimulation fluids are recovered upon flowback of the injected fluid. Studies performed by the US EPA (US EPA, 2004) indicated that approximately 60% of the stimulation fluids are recovered in the first three weeks, and total recovery was estimated to be from 68% to 82%.

Once pumped into the well, the injected stimulation fluids undergo chemical and physical changes in their properties. The general changes to the chemicals that are injected include:

- Acids reacting with minerals and creating salts, water, and carbon dioxide
- Corrosion inhibitors bond with pipe surfaces, are broken down by micro-organisms, or returned as flowback water where they undergo further biodegradation
- Biocides that are degraded by microorganisms or small amount are returned in flowback water where they undergo further biodegradation and photo-degradation
- Friction reducers remain in the formation and are broken down by microorganisms or small amounts returned in flowback water where they undergo further biodegradation
- Surfactant are adsorbed onto the hydrocarbon reservoir surfaces or return with the flowback water where they undergo biodegradation
- Gelling agent broken down by the “breaker” and returns with flowback water where they undergo biodegradation
- “Breaker” reacts with “gel” and “crosslinker” to form ammonia and sulfate salts that are returned in flowback water
- Crosslinker combines with the “breaker” in the formation to create salts that are returned in flowback water.

Comparison of Shale and Conventional Hydraulic Stimulation

Shale hydraulic stimulation treatments utilise essentially the same process and techniques employed in conventional hydraulic stimulation treatments with the main differences being:

- Treatment size – shale stimulations often require 2-3 times the volume / weight of proppant compared to a typical conventional well
- Treatment type – shale stimulation fluids are often friction-reduced water treatments (i.e. “slick water treatments”) which uses less chemical additives than a conventional gas crosslinked fluid fracture treatments.
- Horsepower requirements – shale stimulation can be subject to higher pore pressure and geomechanical stresses than conventional stimulation and therefore require up to twice as many pumping units. Shale treatments generally use a friction reduced water fluid design, which has less viscosity to suspend the proppant. This can be overcome by pumping at a higher fluid rate and utilising more horsepower.

Process

A number of steps are involved in the hydraulic stimulation process to pump the designed fracture treatment:

- Diagnostic Fracture Injection Test (DFIT) to validate and update the proposed stimulation design. This involves injecting a small volume of water, shutting down the surface pumps and monitoring pressure decline to evaluate near wellbore entry friction, fracture gradient, fluid leak off, and minimum horizontal stress. This stage is typically only performed in the exploratory / appraisal stages of development, or until localised fracture characteristics are defined.
- Main stimulation treatment; consisting of pad volume, slurry stages with increasing proppant concentrations, and flush stage to displace last slurry stage through the perforations and into the fracture.
- Mechanical isolation of the completed fracture stimulation stage.
- Perforate the next stage to be hydraulically stimulated and repeat the process above until the final fracture stimulation stage is completed.
- Remove all mechanical isolation devices by milling out the mechanical isolations.
- Flowback well to clean up fracture stimulation fluids and monitor hydrocarbon production. This step may also be combined with an Extended Production Test (EPT) to help define the field reserves and expected production life. The flowback of stimulation fluid is conducted through a separator, which separates and captures liquids, and flares produced gas through a vertical ‘flare stack’.

The above method represents the “plug and perf” technique for fracture stimulation. Another technique is to use coiled tubing assisted annular stimulation which is used to provide a conduit for “pin-point fracturing”. Coiled tubing is run into the well to the deepest target. The bottom-hole assembly run on the end of the coiled tubing incorporates a jetting assembly which allows for low concentration sand slurry to cut holes or slots into the casing and cement. The hydraulic stimulation treatment is then pumped into the coiled tubing / casing annulus to initiate and propagate the fracture.

The final technique is to use “stimulation sleeves”, which are run and cemented in place with the production casing across the shale targets requiring hydraulic fracture stimulation. The smallest internal diameter (ID) stimulation sleeves are run at the base of the well, and sequentially increase in size up to the top stimulation target. Dissolvable metallic stimulation balls are dropped (from smallest to largest), which seat on corresponding stimulation sleeves. The application of differential pressure will open the stimulation sleeve and initiate the hydraulic fracture, as well as hydraulically isolating the previous stimulation target. Once all the stimulation stages have been completed and the wellbore heats up, the stimulation balls dissolve to re-establish a flow path with the shale targets, at which point, the flowback of fluid can commence.

Diagnostics

During a fracture stimulation treatment, computer assisted live monitoring allows for potential problems (surface or down-hole) to be identified and corrected quickly. An example of live monitoring applied to downhole conditions is if pressure communication between the annulus of the well and inside of the well is identified. Where communication is identified, it may be an indication that the first barrier control (as part of the well’s integrity management) has been affected and the treatment will be stopped immediately.

In SA, Santos has trialled the use of advanced stimulation monitoring techniques such as microseismic monitoring, which can be used to evaluate fracture azimuth, fracture height and fracture half length. This information can be further used to calibrate the hydraulic stimulation model predictions. Microseismic monitoring involves the use of sensitive receivers ("geophones") at the surface or within one or more nearby wells to detect and locate in 3D space the releases of energy associated with the propagation of the stimulated fractures.

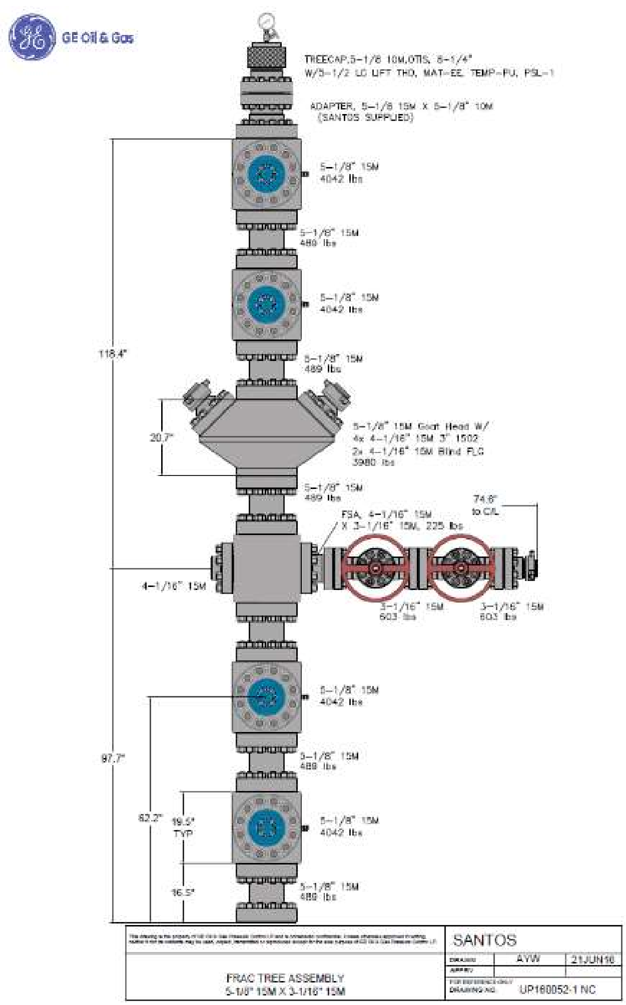
The microseismic results are supported by detailed studies such as by Fisher and Warpinski (2012) which have reviewed height growth data from key unconventional (shale) plays in the US including the Barnett, Marcellus and Woodford shales.

Equipment

The equipment and machinery required to carry out a hydraulic stimulation operation is highly mobile and able to be installed and removed relatively quickly (generally within a couple days). They are designed to comply with state and federal regulations for road transport, and are fitted with safeguards such as an in-vehicle monitoring system (IVMS) to ensure compliance of the individual contractors.

The Wellhead (Figure 9) – used to inject into and control the well, during hydraulic stimulation operations of shale wells. The stimulation fluids, which are injected from the surface via the wellhead, are injected through the perforations in the well casing under high pressures in order to physically fracture the reservoir rock. The wellhead provides the primary surface barriers for well control.

Figure 9 Typical hydraulic stimulation wellhead used in the Cooper Basin for shale stimulation operations



Turkeys nest or above ground storage tanks (Figure 10) – located on site, a synthetic lined pit (turkey's nest) or above ground water storage tank provides temporary water storage for use in the hydraulic stimulation process. Source water can either be trucked or piped along a temporary network. Small dosages of biocide are added to control algal growth particularly under warm and stagnant conditions. Following completion of works, temporary water storage infrastructure is either backfilled or removed from site.

Figure 10 Above ground storage ponds used for stimulation make-up water storage and flowback water storage in the Cooper Basin. Source: Santos 2013

Sand Trailer Unit (Figure 11) – a large, multi-compartment trailer that holds proppant (sand or ceramic material) required for the treatment. When proppant is required, a conveyor system distributes proppant from the compartments to the blender unit.

Figure 11 Sand trailer unit. Source: Halliburton 2012

Blender Units (Figure 12) – In general, two different blending units are used: A pre-gel blender and a down-hole blender. The pre-gel blender combines the source water with additives required for the base stimulation fluid (also known as “linear gel”) and proportions of required additives to provide the final hydraulic stimulation fluid. The down-hole blender unit then proportions proppant to the stimulation fluid to provide the proppant concentrations specified in the treatment design. The final hydraulic stimulation fluid, without proppant, is referred to as the “clean fluid”. The final hydraulic stimulation fluid, with proppant added, is referred to as “slurry”. Chemical additives are precisely measured, controlled and recorded by the blender throughout the stimulation treatment process.

Figure 12 Blender unit. Source: Halliburton 2012

High Pressure Pumps (Figure 13) – reciprocating triplex or quintaplex pumps that receive low pressure hydraulic stimulation fluid from the down-hole blender and inject these fluids at the required higher pressure into the well during the hydraulic stimulation process. 6-20 units may be used on shale hydraulic fracture stimulation treatments. The pumps contain programmable pressure triggers (kick outs) to prevent pressure from exceeding the wellbore design limits. High pressure treating iron connecting the stimulation pumps and the wellhead also contain pressure safety valves (PSVs), which are set to open at a certain pressure set point to ensure the well components are protected.

Figure 13 High pressure pump. Source: Halliburton 2012

Control or Data Acquisition Unit (Figure 14) – telemetry from all units are connected to a central control room during the hydraulic stimulation treatment. Treatment parameter data, including surface and bottom-hole pressure, pumping rate, chemical rate and fluid density, are monitored, recorded and plotted. Treatment supervisors monitor and control the treatment to ensure that the treatment is pumped according to design. Satellite communication facilities allow further 'remote' oversight by technical experts.

Figure 14 Control unit. Source: Halliburton 2012

'Coiled Tubing' Unit (Figure 15) – a Coiled Tubing Unit (CTU) has many uses within Santos operations but is not always required as part of a hydraulic stimulation operation. On some occasions the stimulation treatments are placed using coiled tubing assisted annular fracturing, as opposed to "perf and plug" completions. The coiled tubing can be used in place of wireline jet perforating by jetting holes through the casing and cement using abrasive jetting. Once the perforations are jetted, the coiled tubing is left inside the well and the hydraulic stimulation treatment is pumped down the coiled tubing / casing annulus. Part of the coiled tubing bottom-hole assembly allows a mechanical barrier to be set which protects a stimulated interval below, while pumping a stimulation treatment in a subsequent target above. Following a treatment, the coiled tubing is pulled up to the next interval and the abrasive jetting procedure is repeated.

Figure 15 Coiled tubing unit. Source: Halliburton 2012

Flowback Pond – A higher walled (thicker) plastic lined flowback pond is constructed as part of lease preparation or, as an alternative, an above ground tank (Figure 10) will be installed. This pit/tank is used to receive fluids produced during stimulation operations and during the initial clean-up phase (following stimulation activities). Ponds are double lined with UV stabilised synthetic liners to manage the risk of leaks. Typically, after the initial clean-up phase the produced fluids are treated for re-use or disposed at a licenced waste disposal facility.

1.2.3.4 Injection and isolation of hydraulic fracturing fluid

Once the well has been perforated in the depth interval that is to be hydraulically fractured, fluid injection is performed.

Hydraulic fracturing fluid is injected into the well at the surface through the wellhead. The perforation zones are isolated by either a coiled tubing unit with packers, a bridge plug set by a wireline operator, or by a baffle and ball-drop system.

Following isolation of the perforated zone, injection of fluid commences. The hydraulic fracturing fluid is forced into fractures and remains within the target reservoir. The bore design and construction, comprising multiple physical barriers such as cement and steel casing, ensure that the hydraulic fracturing fluid does not come into contact with overlying strata, including aquifers. The integrity of these barriers is tested before hydraulic fracturing activities are undertaken.

The injection pressure, injection rates, slurry volumes, fluid viscosity, and proppant concentration are monitored in real-time during each injection. Downhole pressure information is also recorded and reviewed during the hydraulic fracture stimulation operation. Down-hole pressures are calculated based on wellhead pressure, fluid density, casing diameter and the depth to the target formation. When a coiled tubing unit is used as part of the operation pressure is monitored: inside the casing above the top packer of the tool, inside the coiled tubing delivering the fluid and inside the wellhead at surface.

Once the entire hydraulic fracturing operation is complete for a well, a completions rig or coiled tubing unit will generally mill out the bridge plugs or baffles that were installed for the hydraulic fracturing operation, to clear them from the well.

1.2.3.5 Return of injected fluid and water (flowback)

Once the injection process is complete, the internal pressure of the rock formation causes fluid to return or “flowback” to the surface through the shale gas well. This fluid contains the dissociation or breakdown products of the injected chemicals plus naturally occurring geogenic compounds.

A considerable volume of the injected fluids are recovered as flowback. Studies performed by the US EPA (US EPA, 2004) indicated that approximately 60% of the fluids are recovered in the first three weeks, and total recovery back to surface was estimated to be from 68–82%.

The flowback water is typically temporarily stored tanks or lined pits before treatment for reuse or disposal.

1.2.3.6 Reuse, treatment and release of wastewater

The recovered fluid, or flowback, is treated and stored for reuse in the next hydraulic fracturing event or disposed of at licensed waste facilities. Waste treatment and management facilities will be modular, factory fabricated and transported to site for assembly and connected to piping, electrical controls and instrumentation. By-products from wastewater treatment are contained in fully engineered, purpose-built structures for further treatment and disposal. Strategic opportunities for further treatment and beneficial use reassessed once composition and technology is assessed.

1.2.3.7 Completions and connections

At the end of the clean-up phase, a workover rig is required to install the production tubing and associated completion equipment such as packers, nipple profiles, tubing hanger, and the production tree, in preparation for connecting the well for inline production flow.

Production from each well is controlled with a metering skid which includes features such as overpressure protection, flow rate control, well safety shut-in, pressure and temperature monitoring.

After the drilling, stimulation, completion and connection activities are complete, the well lease is transitioned towards the operational phase which involves:

- Fencing the drilling mud sump to prevent stock and wildlife access
- Backfilling the well conduits
- Removal of drilling and completions equipment and waste
- Pumping out additional water from the turkey's nest (if installed) and removing the liner or removal of the temporary storage tank.

1.2.4 Rehabilitation

On completion of well, the well lease area is partially rehabilitated to retain a smaller footprint for the remainder of the production lifecycle. If the well is not deemed productive, it is decommissioned and rehabilitated in accordance with landholder agreements and conditions of regulatory approvals.

1.2.4.1 Partial rehabilitation

Once the well is confirmed as economical and ready to be used for production, partial rehabilitation of the well lease area is completed. Partial rehabilitation involves:

- Backfilling the drilling sump
- Partial ripping and re-spreading of topsoil and rootstock on excess lease areas to promote revegetation and stabilisation of the lease edges
- Backfilling the water storage (if installed)
- Backfilling additional pits used for loading and offloading earthmoving equipment
- Removing capping and ripping access loop roads
- Ripping (uncompacting) the camp site and camp access track (unless required for future operations)
- Stabilising and re-establishing growth medium and vegetation.

Examples of partially rehabilitated well lease areas are shown in Figure 16.

Figure 16 Examples of partial lease rehabilitation of producing gas wells in the Cooper Basin

During the wells producing life, which may be 20-40 years, it may be necessary to conduct some workover operations in order to maintain or revitalise the wells producing capacity, or to maintain the level of well integrity required for production. Some workovers may require wireline equipment to lower tools into the hole to undertake operations. For more complex operations, a workover rig is required.

Whilst not exhaustive, such operations may include:

Cleaning out production conduit

- Replacing production tubing
- Plugging the well
- Changing or adding production equipment
- Hydraulic stimulation and re-stimulation operations
- Repairing casing
- Drilling deeper
- Retrieving or drilling out obstructions in the well
- Re-perforating existing zones in production
- Well bore decommissioning.

1.2.4.2 Well decommissioning

When a well comes to the end of its productive life or if the well is drilled and deemed uneconomic to move to the ‘complete’ phase, a decision is made to decommission the well. The primary objective of well decommissioning is to isolate hydrocarbon and water bearing formations and eliminate migration pathways (between the reservoir, other formation / aquifers and surface). Wells earmarked for decommissioning are subject to individual evaluation to determine the most appropriate decommissioning program.

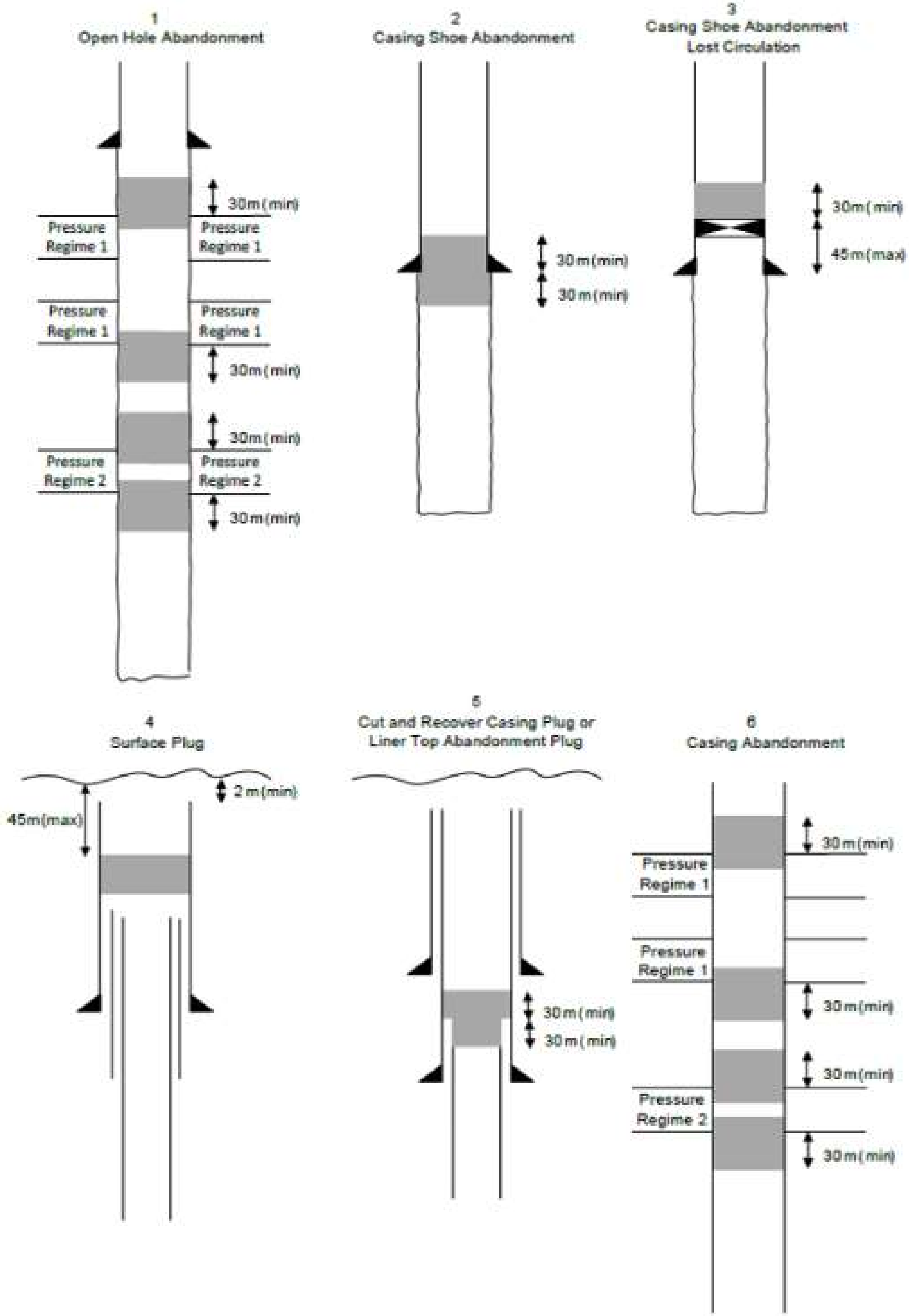
Perforated hydrocarbon zones are isolated with cement plugs and / or bridge plugs and cement bond logs (CBL) used and assessed to ensure that the cement behind the production casing is adequate to avoid migration pathways. If isolation is not evident behind the production casing following CBL integrity checking, the casing will be perforated and squeezed (with cement) to effect isolation. An additional cement plug is placed in the surface casing prior to cutting off the well head below ground level.

Consideration of the following is taken into account when plugging and decommissioning the well:

- Isolate all formations that have hydrocarbon shows
- Isolate formations with different pressure regimes
- Set plugs across intermediate casing shoe (if present) to minimise the potential for cross flow between aquifer systems and hydrocarbon bearing intervals
- Set plugs across surface casing shoe
- At the surface set a plug in the well prior to cutting off the surface casing bowl.

Examples of the decommissioning schematic for completed wells per the Santos Drilling and Completion Management System (DCMS) (Santos, 2016a) are illustrated in Figure 17.

Figure 17 Schematics of required cement barriers for well decommissioning



1.2.4.3 Final rehabilitation

Final rehabilitation is undertaken if the well is uneconomic or at the end of the well's productive life or if there are no ongoing requirements to access the location. Final decommissioning of the well bore and associated surface infrastructure is undertaken once production infrastructure and facilities have been removed. Final surface rehabilitation involves:

- Backfilling pits including the drilling mud sump, water storages (if present)
- Where practicable, removing capping material from the well lease and camp site pad areas and returning material to borrow pits
- Ripping and re-contouring of well leases and camp sites and re-spreading of stockpiled topsoil and cleared vegetation to represent as near as practicable to the original landform
- Removal of capping from the access track and returning to the borrow pit
- Ripping on the contour to promote revegetation and minimise erosion
- Removing windrows (flow on / off controls) to ensure that water flows are not impeded.

An example of a rehabilitated well lease area in the Cooper Basin is shown in Figure 18.

Figure 18 Example of rehabilitated well lease area in the Cooper Basin

2.0 Land access, conduct and compensation

Land access, conduct and compensation are subject to extensive consultation and agreement with landholders, traditional owners and government (in the form of royalties and securities).

As part of seeking approvals to pursue resource development activities (including exploration), Santos prioritises consultation with traditional owners and landholders and confirming acceptable agreements in addition to regulatory approvals.

The surface footprint of hydrocarbon extraction is generally minimal and temporary. Access roads and surface infrastructure such as processing facilities, compressor stations, and some water management facilities are in place for a longer period. These are located and constructed in ongoing consultation with landholders. Access roads are also planned with landholders to accommodate shared use.

Landholders

Santos has demonstrated a clear understanding of the needs and challenges of overlapping and adjacent agricultural businesses – not only through those years of co-existence but also as landholders. Several properties owned by Santos in the Fairview, Wallumbilla, Arcadia Valley and Roma fields of Queensland are used to locate infrastructure and run herds of up to 4,500 head of high quality Droughtmaster cattle.

In Queensland, since January 2011, the Santos-operated GLNG project has secured approximately 1,450 agreements with more than 410 landholders for long-term gas infrastructure alongside their farming businesses. Many hundreds more agreements have been signed for activities such as exploration and pipeline easements.

In addition, GLNG has achieved pleasing results in independent surveys of landholder sentiment conducted by Nielsen Australia. Surveys took place in 2013 and 2014 in areas around Roma, Injune, Arcadia, Taroom, Wandoan and Rolleston. Among the results of the 2014 survey:

- 92% of respondents said they would allow Santos back onto their property. This was the same result from the 2013 survey.
- 94% were satisfied or more satisfied with the relationship than 12 months prior.
- 92% said they had sufficient time to prepare, understand and negotiate a Conduct and Compensation Agreement.

Notably, 75% of the respondents had construction work taking place on their properties at the time of the survey – the period of highest activity and therefore potential inconvenience for landholders.

Santos is committed to treating landholders with respect at all times. We have a strong track record of respectful and constructive engagement with landholders. Consultation seeks to ensure the right information is provided in a timely manner and in an appropriate fashion, recognising the busy lives and pressures already placed on landholders. We work through a series of steps encompassing phases of initial meetings and property mapping, negotiating agreements including location of infrastructure, compensation and conditions specific to the property, the construction period, and then ongoing engagement as required.

Santos pays a landholder's legal fees (to an agreed value) to allow for the independent review of a proposed CCA.

There is a wide range of potential benefits for landholders as a result of natural gas activity on their properties, beyond the compensation paid to directly offset the footprint and inconvenience of natural gas activities (In 2015, Santos paid approximately $11 million in compensation to landholders across its onshore activities). These include:

- Additional income streams from natural gas activity would be a welcome addition to any farming business grappling with the adverse effects of ongoing drought conditions. Income can be generated through, for example, the sale of raw materials such as gravel for road construction.
- New farm infrastructure that enhances the farming business. For example, access roads to gas wells located to the advantage of the landholder
- Opportunities for employment. There are numerous examples of landholders gaining employment with companies or their contractors. Employment opportunities for young people in particular are helping to reverse the trend of regional population decline by providing additional career options in regional area.
- Additional selling point for properties on the market. There is anecdotal evidence of properties being advertised in Queensland for sale with 'gas wells' listed as a selling feature over recent years, and this is likely to continue.
- Improved community infrastructure and services. Santos has a strong track record of contributing to communities with a focus on health, education, infrastructure, the environment, youth, indigenous opportunities, local businesses, the arts, community organisations and events, and volunteering. In Queensland, GLNG has made over $200 million worth of contributions to regional communities, including important legacy investments in major infrastructure including road upgrades and maintenance; aeromedical services; airports; affordable housing and rent assistance initiatives; sewerage infrastructure; and weed and management programs.

Traditional Owners

Santos has negotiated close to 50 agreements across Australia in relation to access to native title land or Aboriginal land, and the company works with closely with Traditional Owners on cultural heritage, including engaging Aboriginal people to help identify, and manage the risk to, cultural heritage arising from our activities.

These agreements are negotiated on a foundation of early and fully informed consent.

3.0 Conclusion

We hope this submission assists the Inquiry Panel in its deliberations and leads to recommendations that allow the development of the shale gas industry in WA. We note, in the draft final report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (Pepper Inquiry, December, 2017), the Panel concludes that the risks associated with hydraulic fracturing can be minimised to an acceptable level and in some instances avoided altogether. A recurrent theme in the Pepper Inquiry report is the need for a robust regulatory regime and Santos strongly supports this position. But we caution against a 'prescriptive' management of risk rather than 'objective' risk management. There are some areas where it makes sense to be prescriptive (e.g. well integrity code of practice) but prescriptive over-regulation could make any exploration, development and production opportunity cost-prohibitive and stifle innovation.

Santos stands ready to assist the Inquiry Panel should it seek further information or clarification on any aspect of this submission. It also extends an invitation to the Inquiry Panel to visit the company's operations in the Cooper Basin to witness first-hand hydraulic fracturing and associated activities.

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