Underground Water Impact Report
Nappamerri Trough Natural Gas ATP 855

Prepared for:	**Beach Energy Ltd**	19 February 2016

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SYNOPSIS

Queensland petroleum legislation and regulations require tenure holders to monitor water extraction from oil and gas wells, and prepare an Underground Water Impact Report (UWIR) to provide information about underground conditions and the effects of water extraction.

Beach Energy completed the Stage 1 exploration and testing program as operator of the Authority to Prospect 855 (ATP 855), Cooper Basin, south-west Queensland. The Nappamerri Trough Natural Gas (NTNG) joint venture is investigating a shale gas and basin-centred gas prospect via deep wells (3350 to 4200 metres) in the Permian sediments of the Cooper Basin, below the regional seal (aquitard) formed by the thick Nappamerri Group separating the Cooper and Eromanga Basin (GAB) sediments. Basin-centred gas systems are defined as low-permeability, gas-saturated reservoirs that are abnormally pressured, regionally pervasive, and lack down-dip water contacts (Law, 2002).

Underground water extractions relating to the NTNG Stage 1 operations in ATP 855 have involved:

- production testing from Cooper Basin (Permian) sediments at five sites (Halifax-1, Hervey-1, Etty-1, Redland-1, and Geoffrey-1); a total of 30 ML was injected and 24 ML extracted (Keppel-1 was not stimulated but was plugged and abandoned due to high gas flow).
- water extractions totalling 68 ML from the 65 m deep sub-artesian Winton Formation (Eromanga Basin) water supply bore at the Halifax site; of which 20 ML was injected for the Halifax-1 fracture stimulation and 48 ML was input to the RO treatment plant to generate 28 ML of treated water for stimulation operations spread across the four other sites.

Conservative analytical modelling identifies an affected area of less than 3 km. Monitoring at the Halifax water bore did not show any pressure or flow effects during test production. There are no third party bores within 3 km of any Beach site and the nearest GAB springs are more than 200 km to the south-east. The formations accessed for these extractions are not listed in the Management Areas/Units and Aquifers for the Central Management Zone under Schedule 4 of the Water Resource (GAB) Plan 2006. Test production to date has been low volume, and as the timing of future production testing is very uncertain, a monitoring plan is considered not required.

Nevertheless, Beach commits to reviewing this UWIR annually and to provide a summary of the outcome of each review to the Chief Executive of the relevant department (DEHP at the time of writing). The first annual review is scheduled to occur one year after approval of this UWIR, and a new UWIR will be compiled every 3 years and submitted to DEHP.

This report is submitted in accordance with the Water Act 2000 and it shows that petroleum operations and the related exercise of underground water rights at ATP 855 have had negligible impact on underground water in the region. This applies to both the Cooper Basin reservoir unit from which short term test production has been extracted, and to the shallow aquifers that third parties might use boreholes from which to extract water. There are no plans to undertake production or testing in the near future.

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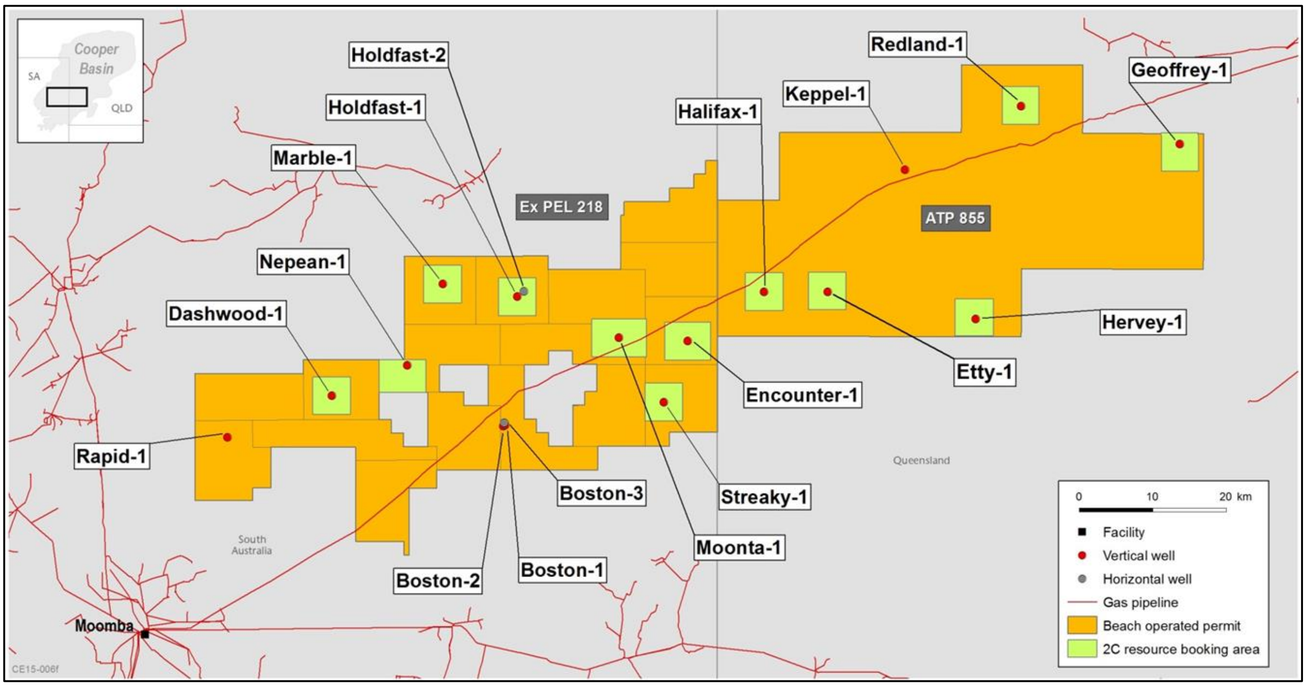
1. INTRODUCTION

Petroleum legislation and associated regulations require that petroleum tenure holders in Queensland monitor their water extraction from petroleum and gas wells (State of Queensland, 2015), and prepare an Underground Water Impact Report (UWIR) to describe, make predictions about and manage the impacts of extraction of underground water where production testing or production is taking place. The UWIR must document the water volumes produced, as well as the projected production over the next three years.

During the period 2012-2015, Beach Energy has completed Stage 1 of an exploration and production testing program as operator of the Authority to Prospect 855 (ATP 855), Cooper Basin, south-west Queensland (Figure 1). The Nappamerri Trough Natural Gas (NTNG) joint venture is investigating the Permian shale gas and basin-centred gas prospect.

Figure 1 – Beach operated ATP 855 tenement and wells (also showing Ex PEL 218 in SA)



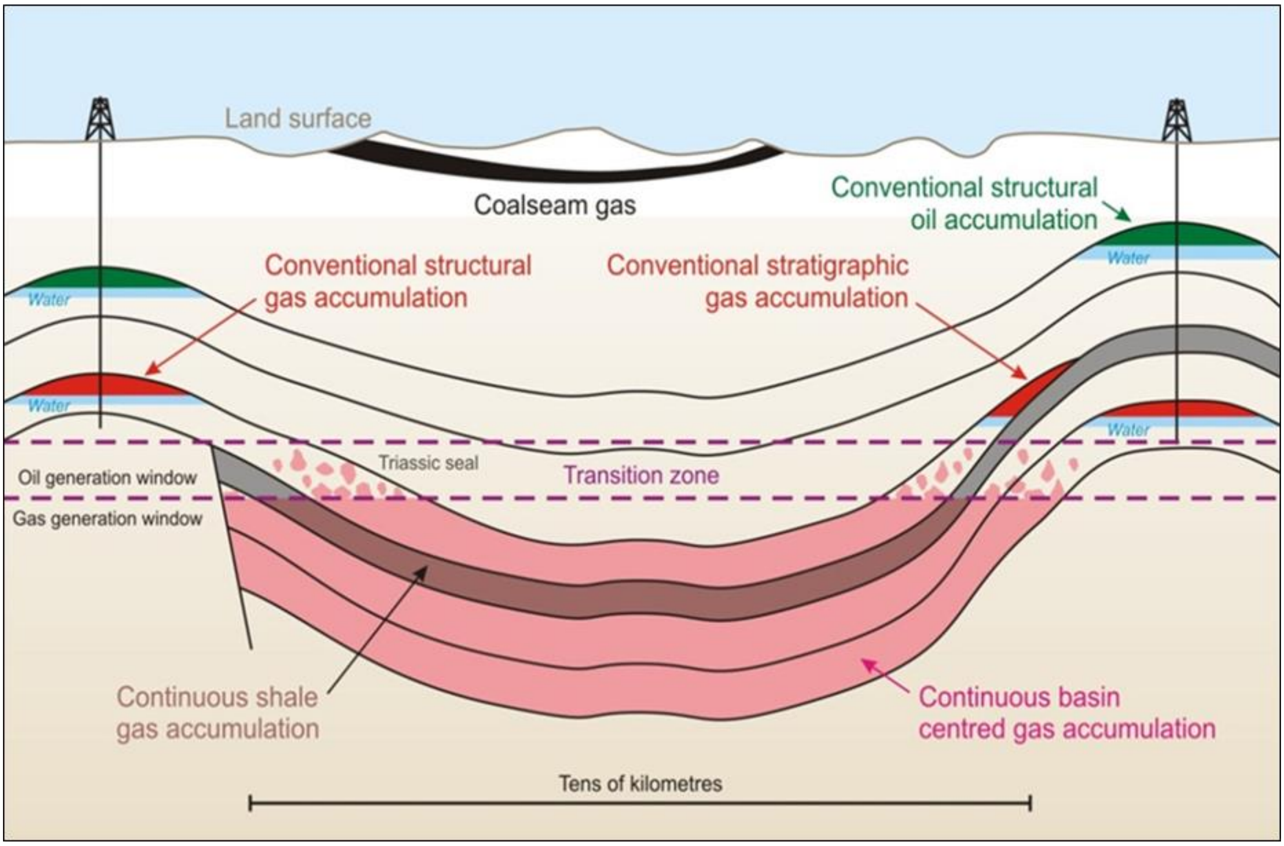
1.1 Basin-Centred Gas and Shale Gas Targets

The NTNG Stage 1 exploration targets fall within the category of 'tight' gas or 'unconventional' gas as they have lower permeability than conventional oil and gas reservoirs (Beach, 2012a). The wells are located at depths of about 3350 to 4200 metres in the Permian sediments of the Cooper Basin, below the regional seal (aquitard) formed by the thick Nappamerri Group of the upper Cooper Basin and underlying the Eromanga Basin (Great Artesian Basin) sediments.

Shale gas, tight gas and basin-centred gas are generally termed as unconventional gas however the term 'unconventional' does not refer to either the gas itself or the methods used to extract it (Beach, 2012a). There is no difference between gas produced from conventional reservoirs and that produced from basin-centred or shale gas. The gas is still sourced from organic matter and is natural gas that can be processed and distributed. The methods of extraction have been in common use for conventional oil and gas for decades, including in the Cooper Basin.

The difference between conventional and unconventional gas refers to where the gas is found and produced from underground. Exploration for unconventional targets focuses on shale and tight oil and gas systems where hydrocarbons have been generated but have not been able to migrate, rather than on underground structures such as anticlines and highly permeable sandstones that are targeted by 'conventional' gas plays (Figure 2).

Figure 2 - Conventional and unconventional play types (after Schenk and Pollastro 2002)



Due to the very low permeability of the source rock or surrounding strata adjacent to the source, the gas in unconventional plays becomes regionally trapped by an inability to migrate further, rather than a geological structure (Figure 2 above depicts the presence of shale gas and basin-centred gas in a deep trough not confined by a structure). As the gas is not pooled in discrete traps, these “unconventional” hydrocarbon accumulations are also known as continuous plays. The shales and tight gas intervals tend to extend over vast distances; in the case of the Nappamerri Trough, extending over several thousands of square kilometres (Figure 1). In summary, basin-centred gas systems are defined as low-permeability, gas-saturated reservoirs that are abnormally pressured, regionally pervasive, and lack down-dip water contacts (Law, 2002).

1.2 Nappamerri Trough Natural Gas (NTNG) Project

The fracture stimulation of NTNG gas wells involves the injection of fluid, mostly water, to create small cracks or fractures in the low permeability sandstone and shales formations near the gas well, which allow gas to flow to the well more easily (Beach, 2012a).

Fracture stimulation of conventional oil and gas reservoirs has been carried out in several hundred wells in the Cooper Basin since 1968, to improve the commerciality of lower permeability zones. These are the same formations that Beach is now exploring for basin-centred gas in the Nappamerri Trough. It is considered to be a relatively routine and low risk component of oil and gas drilling and well operations in this basin.

Beach has announced (www.beachenergy.com.au) that it considers that the NTNG Stage 1 exploration phase has achieved its primary technical objectives, including:

- Improve the geological understanding and delineate (geographically and vertically) the target zones (6 wells have been drilled across ATP 855; another 12 wells have been drilled on SA permit Ex PEL 218)
- Test fracture stimulation techniques and technologies for optimal design

- Identify and prioritise basin-centred gas play type for future appraisal activities (Daralingie and Patchawarra sand plays)
- Complete short term production testing to flow gas and test deliverability (all wells in ATP 855 flowed gas to surface).

As explained in Section 1.3 below, this UWIR presents information relating to the effects of underground water extractions in ATP 855.

Table 1 summarises the NTNG Stage 1 program in ATP 855. Beach is reviewing the data and outcomes with its joint venture partner (Icon Energy), and is preparing the scope and objectives for future stages of exploration. The Stage 2 exploration scope is planned to be confirmed by late 2016, subject to ongoing discussions with current and potential future joint venture partners of Beach Energy.

Table 1 – NTNG Stage 1 (ATP 855) summary

ATP 855 Gas Well [Formation at Total Depth]	Drilled	Total Drilled Depth (m) [Cased Depth Comp-letion]	Fracture Stimulation Intervals/Stages, Formations and Water Source							Test Production Date [Total Volumes of Water Injected and Produced via Flowback [ML]]
			Patchawarra	Murteree	Epsilon	Roseneath	Daralingie	Toolachee	Water Source: (Halifax Bore, 65m deep, Winton Formation)	
Halifax-1 [Patchawarra]	Dec-12	4266 [4205]	7	1	2	2	1	1	Halifax Bore	Jan-Aug 2013 [19.9 ML injected 15.7 ML flowback]
Hervey-1 [Patchawarra]	Sept-14	4269 [3692]	1	-	-	-	1	3	Halifax bore, RO treated	Oct-Nov 2014 [3.7 ML injected 2.4 ML flowback]
Etty-1 [Patchawarra]	Oct-14	3807 [3354]	-	-	-	-	1	3	Halifax bore, RO treated	Oct-14 - Jan-15 [2.3 ML injected 2.5 ML flowback]
Redland-1 [Daralingie]	Oct-14	3804 [3763]	-	-	-	-	1	3	Halifax bore, RO treated	Dec-14 [1.7 ML injected 0.5 ML flowback]
Geoffrey-1 [Patchawarra]	Nov-14	4124 [4119]	4	-	1	-	-	-	Halifax bore, RO treated	Dec-14 - Jan-15 [2.6 ML injected 2.5 ML flowback]
Keppel-1 [Epsilon]	June-13	3898 [plugged]	-	-	-	-	-	-	Not stimulated	(Plugged and Abandoned; well control, high gas flow)

1.3 Underground Water Impact Report (UWIR)

Petroleum and gas companies in Queensland do not require a water authorisation under the Water Act 2000 to take water for fracture stimulation as the industry has a right to underground water subject to obligations established under Chapter 3 of that legislation. As a result, the Plan (Water Resource (Great Artesian Basin) Plan 2006) has no role in defining water access arrangements for the shale gas industry (State of Queensland, 2015).

However, Chapter 3 of the Water Act requires:

- petroleum tenure holders to monitor and assess the impact on water bores due to the exercise of underground water rights
- preparation of underground water impact reports that establish underground water obligations, including obligations to monitor and manage impacts on aquifers and springs.

For a petroleum tenure not within a declared Cumulative Management Area (CMA), the entity responsible for preparation of UWIRs is the tenure operator. In this case, the Cooper Basin is not within a declared CMA, and thus the responsible entity for ATP 855 is Beach Energy.

UWIRs must contain information consistent with the guideline parts (DEHP, 2015), and this report has been structured accordingly:

- Part A: Information about underground water extractions resulting from operators exercising their underground water rights
- Part B: Information about aquifers affected, or likely to be affected (Immediately Affected Areas (IAA) and Long Term Affected Areas (LTAA)), to assist with management of impacts of the exercise of water rights by tenure holders
- Part C: Maps showing the area of affected aquifer(s) where underground water levels are expected to decline
- Part D: A water monitoring strategy
- Part E: A spring impact management strategy
- Part F: not required in this case, as ATP 855 is not within a Cumulative Management Area.

1.4 Data Sources and Assessment Methods

This desktop UWIR study used the following data sources:

- UWIR guideline (DEHP, 2015) and latest Minister's Performance Assessment Report (State of Queensland, 2015)
- maps, imagery, data and documentation relating to exploration and testing activities on ATP 855 (provided by Beach), notably including monitoring data from the Stage 1 NTNG program and related analysis and numerical modelling of pressure changes
- Government agency online databases and GIS data
- available/published information on the hydrogeology and hydrology of the area (see references for details).

2. PART A – UNDERGROUND WATER EXTRACTIONS

The NTNG Stage 1 program in ATP 855 involved fracture stimulation activities at Halifax-1, Hervey-1, Etty-1, Redland-1, and Geoffrey-1, in that order (see Figure 1 and Table 1 previously). Production testing was also undertaken at these five sites. At the sixth site, Keppel-1 was drilled but then was plugged and abandoned.

Underground water extractions relating to the NTNG Stage 1 operations in ATP 855 have involved:

- production testing from the deep (Permian) sediments of the Cooper Basin at five sites
- extractions totalling 68 ML over two years (2013-2014) from the 65 m deep sub-artesian (Winton Formation) water supply bore at Halifax.

The formations accessed for these extractions are not listed in the Management Areas, Management Units and Aquifers for the Central Management Zone under Schedule 4 of the Water Resource (Great Artesian Basin) Plan 2006.

There has been no full scale production to date, and there are no immediate plans for additional production testing from ATP 855.

Discussions with the Department of Environment and Heritage Protection (DEHP) regarding the development of UWIRs for unconventional exploration activities have confirmed that the exercise of underground water rights in this case is largely the take of water from the sub-artesian Winton Formation ("Halifax bore"), and that this should be the focus of this UWIR. Hence, this report incorporates a hydrogeological impact assessment analysis (section 3.7) assuming a hypothetical average extraction from the Halifax sub-artesian water bore of 1 L/s, although there are no immediate plans for additional production. The other information presented herein on the fracture stimulation operations is retained for completeness.

2.1 Water Supply for Fracture Stimulation Operations

The 65 m deep (Winton Formation) sub-artesian water supply bore at the Halifax site ("Halifax bore") was used as the source water for the five stimulation treatments on ATP 855. Extractions from the sub-artesian Halifax bore do not have potential to materially impact on GAB bores or springs given the low volumes involved and horizontal and vertical isolation factors (more detailed assessment of Affected Areas is provided later in section 3.7):

- the Halifax site is the most westerly of the ATP 855 wells, located about 7 km from the SA border, and hence is very remote from the nearest registered GAB springs (which are in excess of 200 km away), as shown later in Figure 10
- the Halifax bore is completed in the Winton Formation to a depth of about 65 m (see Appendix A); extraction rates lie in the range 1-5 L/s for intermittent periods within a total period of 2 years, totalling 68 ML to date (i.e. averaging 1 L/s over 2 years)
- the shallow sub-artesian Winton formation is vertically isolated from the main GAB aquifers that occur between about 1700 m and 2300 m depth (at Halifax-1) by the aquitard units of the Mackunda Formation and Allaru Mudstone, and notably by the 300-400 m thick regional seal (aquitard) of the Wallumbilla Formation (Bulldog Shale).

The total dissolved solids (TDS) in the Halifax bore water ranges from 12,300 to 13,100 mg/L (i.e. suitable for industrial purposes only). For the first stimulation stage at Halifax-1 (14 stages in total), the sub-artesian Halifax bore source water was not treated.

To reduce scale buildup even further, a RO water treatment plant was commissioned. As the Halifax bore water quality was deemed to be as good as if not better than that from the other shallow bores drilled in ATP 855, it was used as the RO feed water. The RO permeate (treated) water had a salinity of 50-100 mg/L TDS (equivalent to rainfall) and was used in the fracture stimulation treatments at the other sites. A total of 68 ML was extracted from the sub-artesian Halifax water bore for the NTNG Stage 1 program. The RO permeate was stored in additional ponds constructed on site at Halifax. Treated water was trucked to water holding ponds at the other four sites (Hervey-1, Etty-1, Redland-1, and Geoffrey-1) for use in the fracture stimulation operations. The RO plant was decommissioned on 2 November 2014.

The fracture stimulation and production testing activities for the NTNG Stage 1 operation since 2012 were summarised previously in Table 1. The total water volume extracted from the sub-artesian Halifax bore (Winton Formation) to support these activities amounts to 68 ML (Table 2), based on analysis of RO plant daily reports and fracture stimulation operation reports.

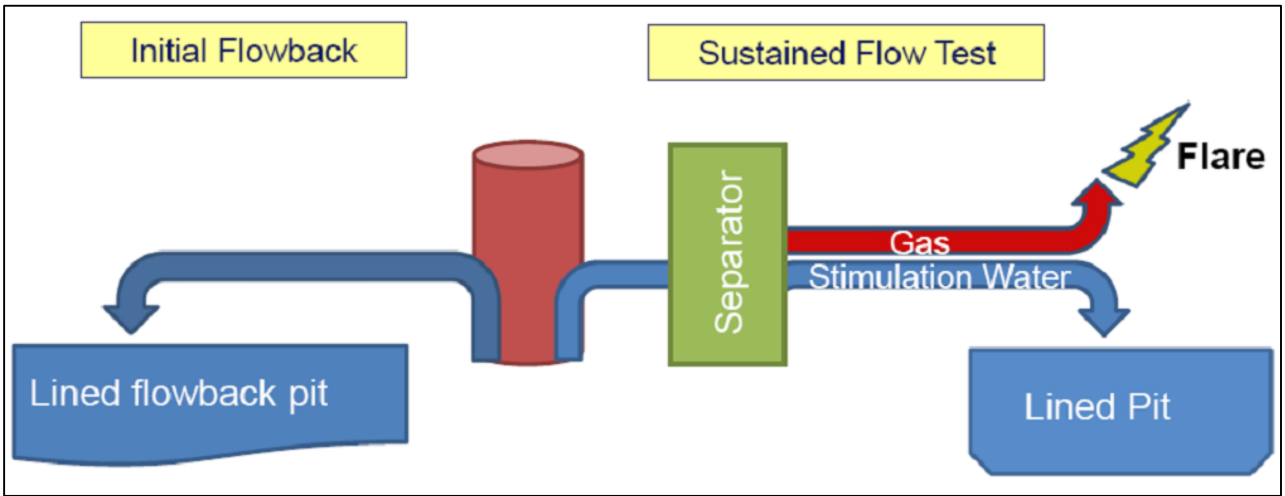
Table 2 - sub-artesian Halifax water bore (Winton Formation) extractions summary

Extraction from sub-artesian Halifax water bore	Period	Volume (ML)
Untreated volume injected to Halifax-1	January to August 2013	20
Metered volumes of RO permeate produced for treatments at: Hervey-1, Etty-1, Redland-1, and Geoffrey-1	August to November 2014	28
RO reject (estimated at 70% of permeate volume)	August to November 2014	20
Total extracted from sub-artesian Halifax water bore	January 2013 to January 2015	68

2.2 Production Testing Flowback

Production testing was undertaken following installation of the tubing string in the gas well. As the initial flow back was predominantly recovered stimulation fluid, production was directed to a lined pond adjacent to the flare pit well (Figure 3, after Beach 2012a). Once the well began to recover gas, the flow was directed to the separator. The gas from the top of the separator was metered and sent to the flare where it was burnt. The water from the bottom of the separator was metered and directed to one of the lined temporary water storage ponds used to hold water for the fracture treatment. The gas stream was sampled for composition and contaminants. The recovered water was also sampled on a regular basis to evaluate its composition, and samples were also obtained from lined storage ponds for analysis.

Figure 3 - Flowback and production testing process (after Beach, 2012a)



During the flowback period the rate of production of the recovered fluid gradually reduced, as shown in the time series plots of Figure 4 to Figure 8 for each of the wells in ATP 855 (in chronological order of testing). The volumes involved are summarised (in ML) in Table 3. The following conclusions may be drawn:

- The longest production test was at Halifax-1, over the 9-month period January to September 2013, which also involved the greatest volumes, with Figure 4 showing that the recovered fluid volume was about 80% of the injected volume (almost 20 ML injected and almost 16 ML recovered in total).
- Short production tests of 1-3 months were undertaken at Hervey-1 and Redland-1, involving small volumes of up to 4 ML; Figure 5 and Figure 7 show that the recovered fluid volume was about 70% and 30% of the injected volume (respectively).
- The short production test of 2 months at Geoffrey-1 over the period November 2014 to January 2015 involved a volume less than 3 ML, but in this case Figure 8 shows that the recovered fluid volume was almost 100% of the injected volume
- The 3 month production test at Etty-1 over the period October 2014 to January 2015 was the only case where the test production volume exceeded the injected volume; Figure 6 shows that the recovered fluid volume was about 10% more than the injected volume at Etty-1, by just 0.2 ML compared to an injected volume of 2.3 ML.

Table 3 - ATP 855 test production summary

ATP 855 Gas Well	Test Production Date	Fracture Stimulation Intervals/Stages and Formations						Total Volume of Water Injected [ML]	Total Volume of Water Produced via Flowback [ML]
		Patchawarra	Murteree	Epsilon	Roseneath	Daralingie	Toolachee		
Halifax-1	Jan to Aug 2013	7	1	2	2	1	1	19.9 ML	15.7 ML
Hervey-1	Oct to Nov 2014	1	-	-	-	1	3	3.7 ML	2.4 ML
Etty-1	Oct 2014 to Jan 2015	-	-	-	-	1	3	2.3 ML	2.5 ML
Redland-1	Dec 2014	-	-	-	-	1	3	1.7 ML	0.5 ML
Geoffrey-1	Dec 2014 to Jan 2015	4	-	1	-	-	-	2.6 ML	2.5 ML
Keppel-1	-	-	-	-	-	-	-	(Plugged and Abandoned; well control, high gas flow)	
Totals	**Jan 2013 to Jan 2015**	12	1	3	2	4	10	**30.2 ML**	**23.6 ML**

As will be explored in more detail later, water production from the ATP 855 gas wells (or indeed the sub-artesian Halifax water bore) do not have the potential to materially impact on GAB bores or springs given the low volumes involved and the horizontal and vertical isolation factors, notably:

- the nearest registered GAB springs are in excess of 200 km to the south-east of ATP 855, as shown later in Figure 10
- all the ATP 855 gas wells are completed in Cooper Basin (Permian) formations at depths ranging from 3350 to 4200 metres
- the Permian formations are vertically isolated from the Eromanga Basin (Jurassic-Cretaceous) GAB aquifers that occur between about 1700 m and 2300 m depth (at Halifax-1) by the thick (>600 m) regional seal (aquitard) of the Nappamerri Group (Triassic)
- the sub-artesian water bore at Halifax is completed to 65 metres depth in the Winton Formation (Late Cretaceous), vertically isolated from the Eromanga Basin main confined GAB aquifers by the thick (~400 m) regional seal (aquitard) of the Wallumbilla Formation (Bulldog Shale), and only 68 ML was extracted over a 2 year period (2013-2014).

Figure 4 - Halifax-1 fracture stimulation flowback

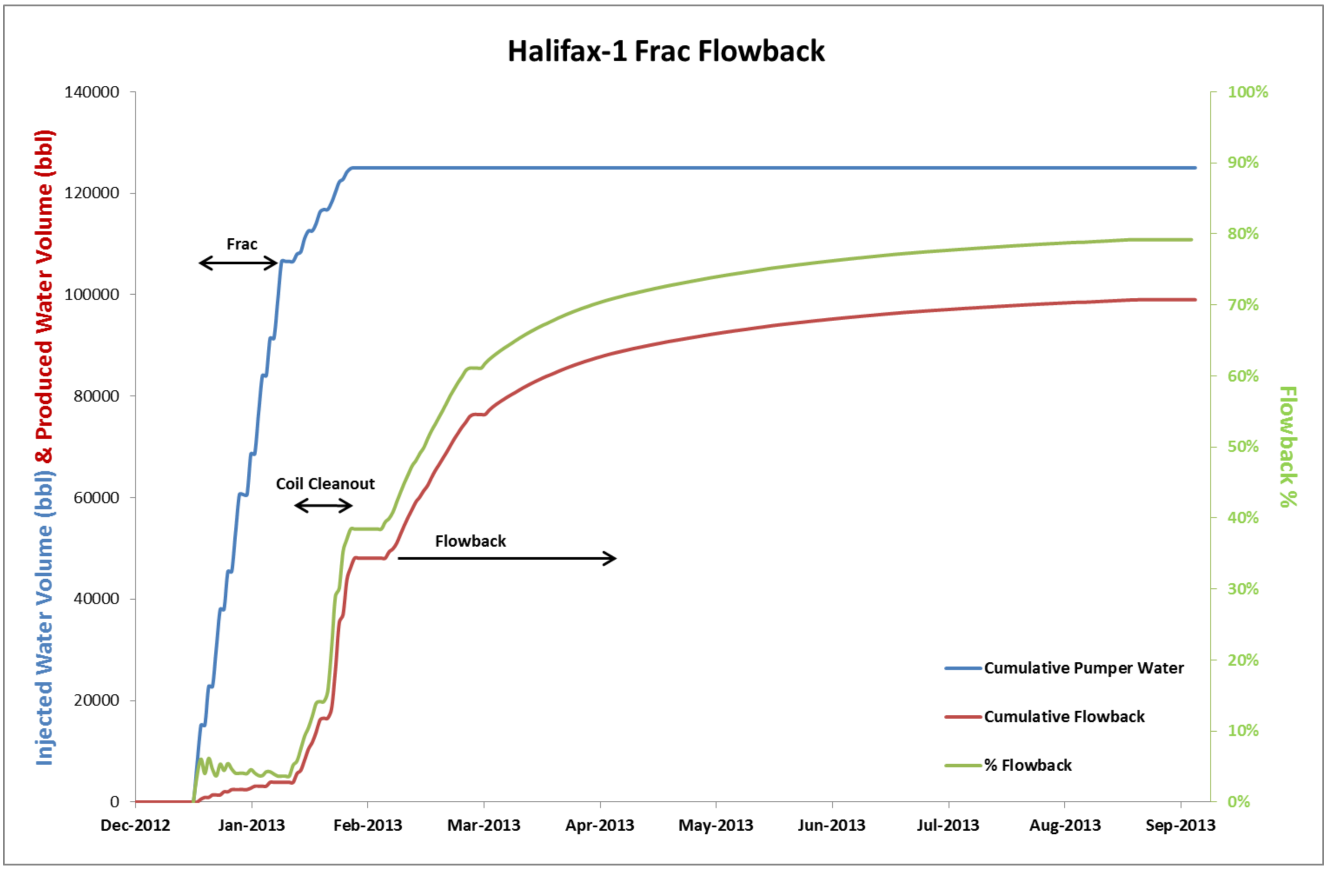


Figure 5 - Hervey-1 fracture stimulation flowback

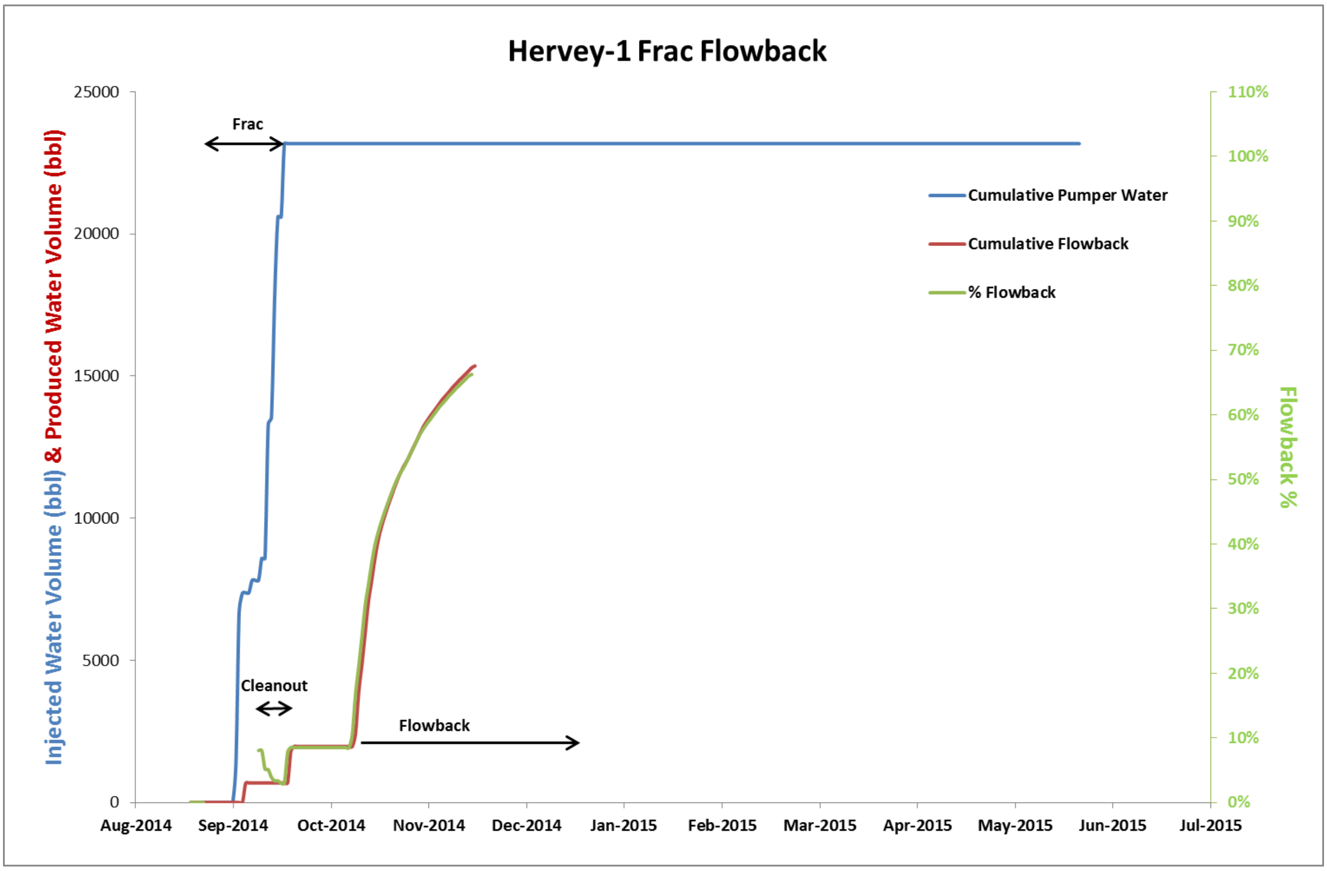


Figure 6 - Etty-1 fracture stimulation flowback

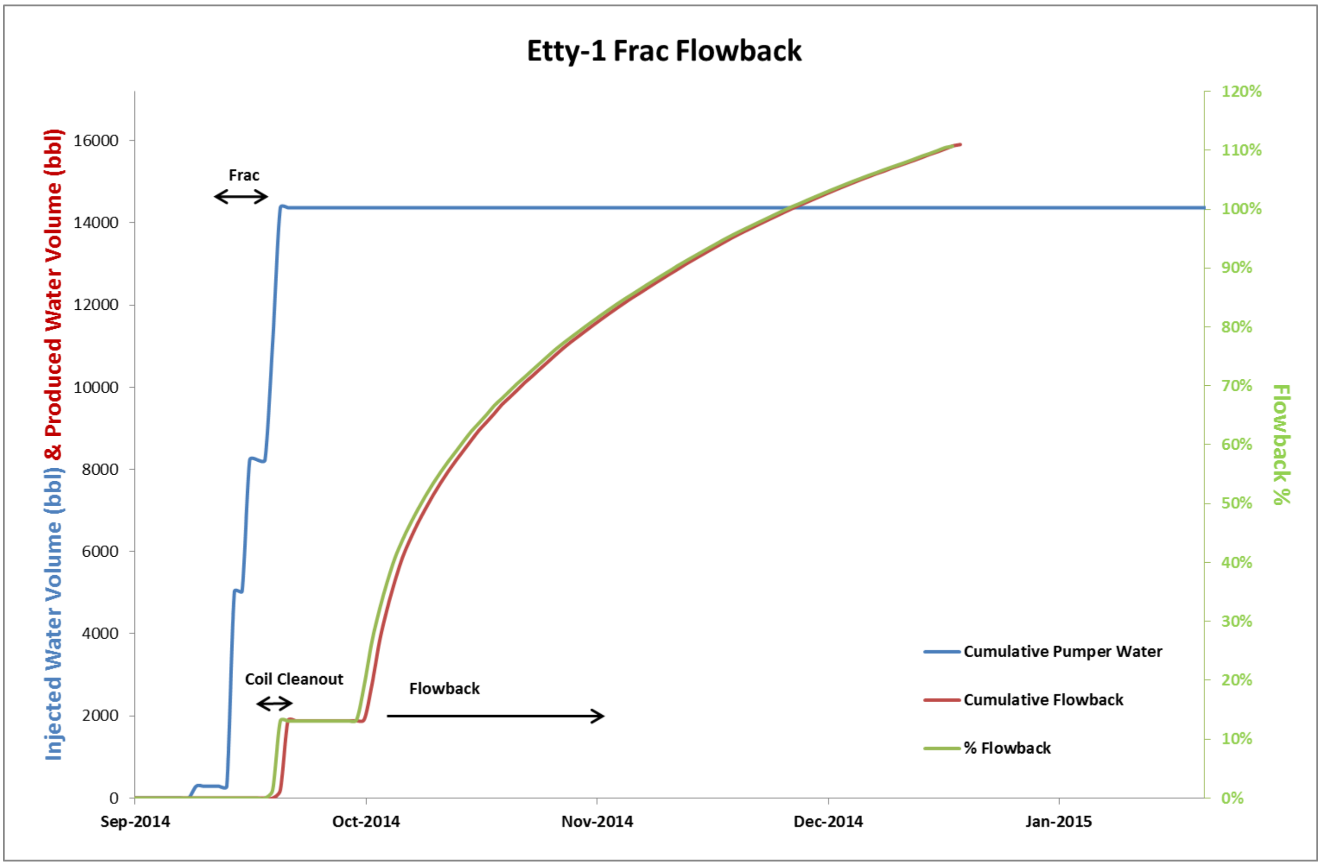


Figure 7 - Redland-1 fracture stimulation flowback

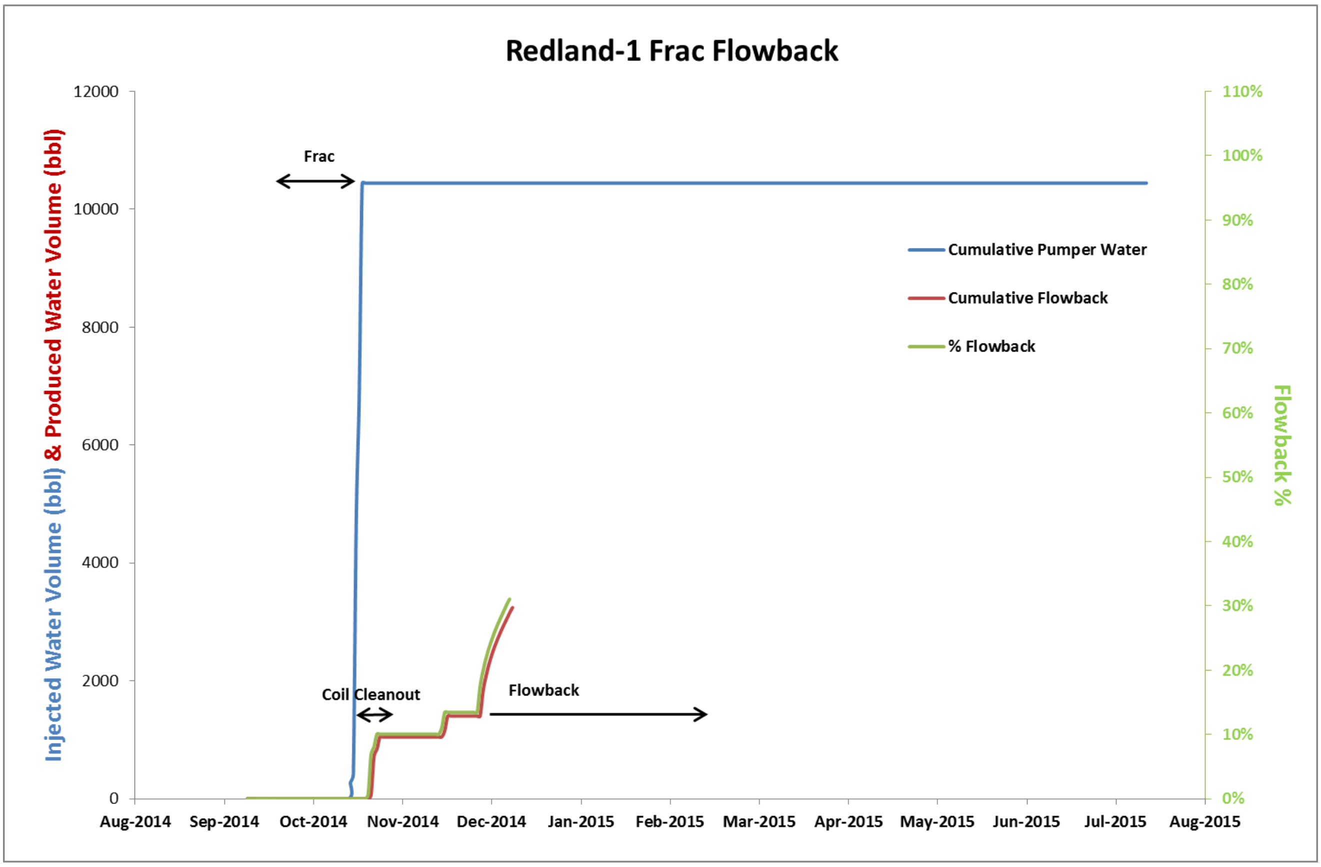
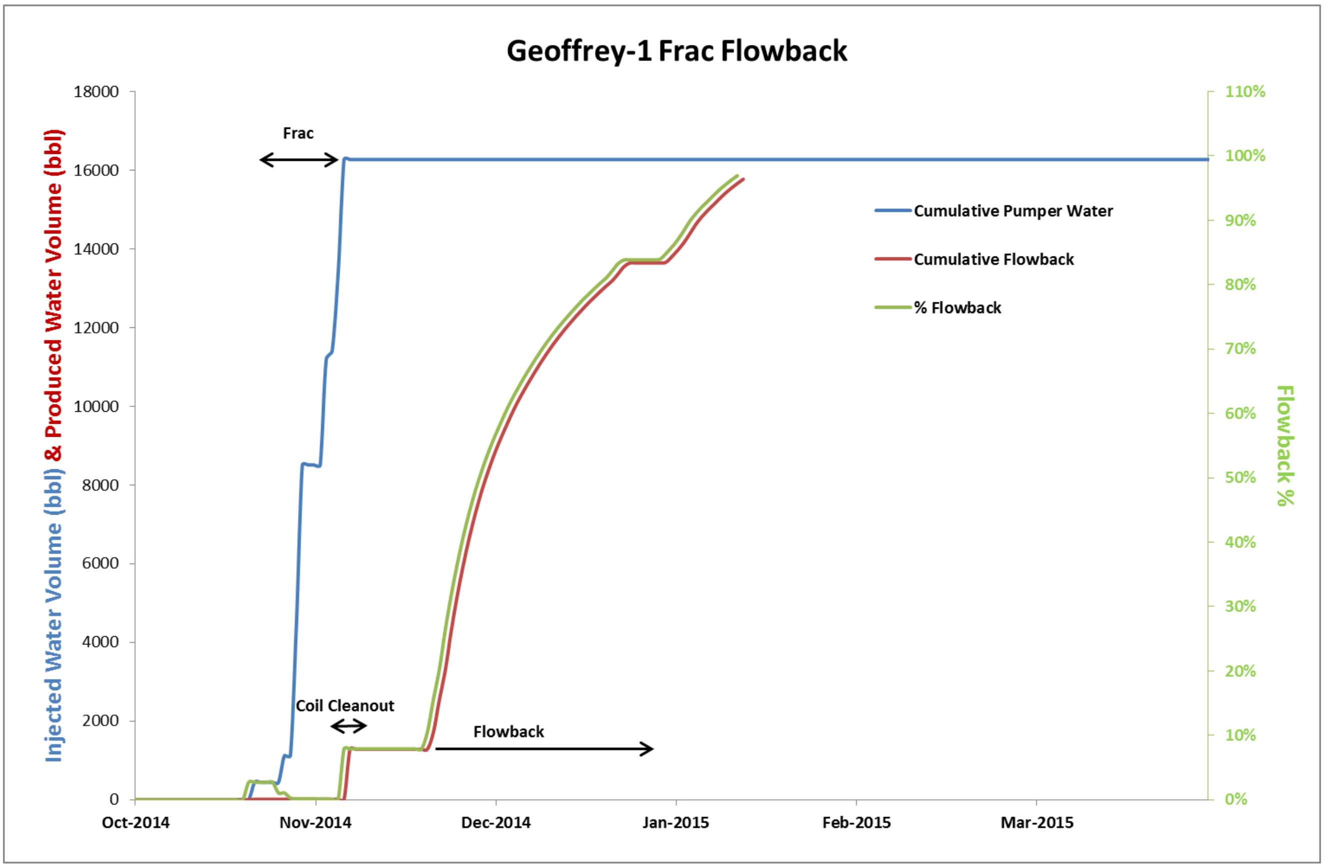


Figure 8 - Geoffrey-1 fracture stimulation flowback



3. PART B – AQUIFER INFORMATION

The Permian (Cooper Basin) and late Cretaceous (Eromanga Basin) formations accessed for the extractions from ATP 855 are not listed in the Management Areas, Management Units and Aquifers for the Central Management Zone under Schedule 4 of the Water Resource (Great Artesian Basin) Plan 2006. Extractions have occurred from the Permian formations underlying the Jurassic-Cretaceous GAB (Eromanga Basin) aquifers, and the sub-artesian late Cretaceous aquifers of the upper GAB. Both have poor hydraulic connection with the main confined GAB aquifer systems (despite the over-pressured Cooper Basin formations). Appendix A presents summary information from government database records.

3.1 Project Area Physiography

ATP 855 is located in the remote Channel Country of south-west Queensland (Figure 9) which is sparsely populated, with the nearest notable feature being Nappa Merrie Station, located 30 km north-west of Hervey-1. Land uses in ATP 855 comprise pastoral station operations, oil and gas exploration, production and processing, and conservation and tourism.

The Cooper region of south-west Queensland is arid, with low rainfall and high evaporation during hot dry summers and mild dry winters. Rainfall in the area is highly erratic, with no distinct seasonal rainfall pattern. Silo data indicates annual average rainfall of around 200 mm, but this can be recorded in a single rainfall event due to localised, intense rainfalls associated with thunderstorm activity. Pan evaporation exceeds 3000 mm per year.

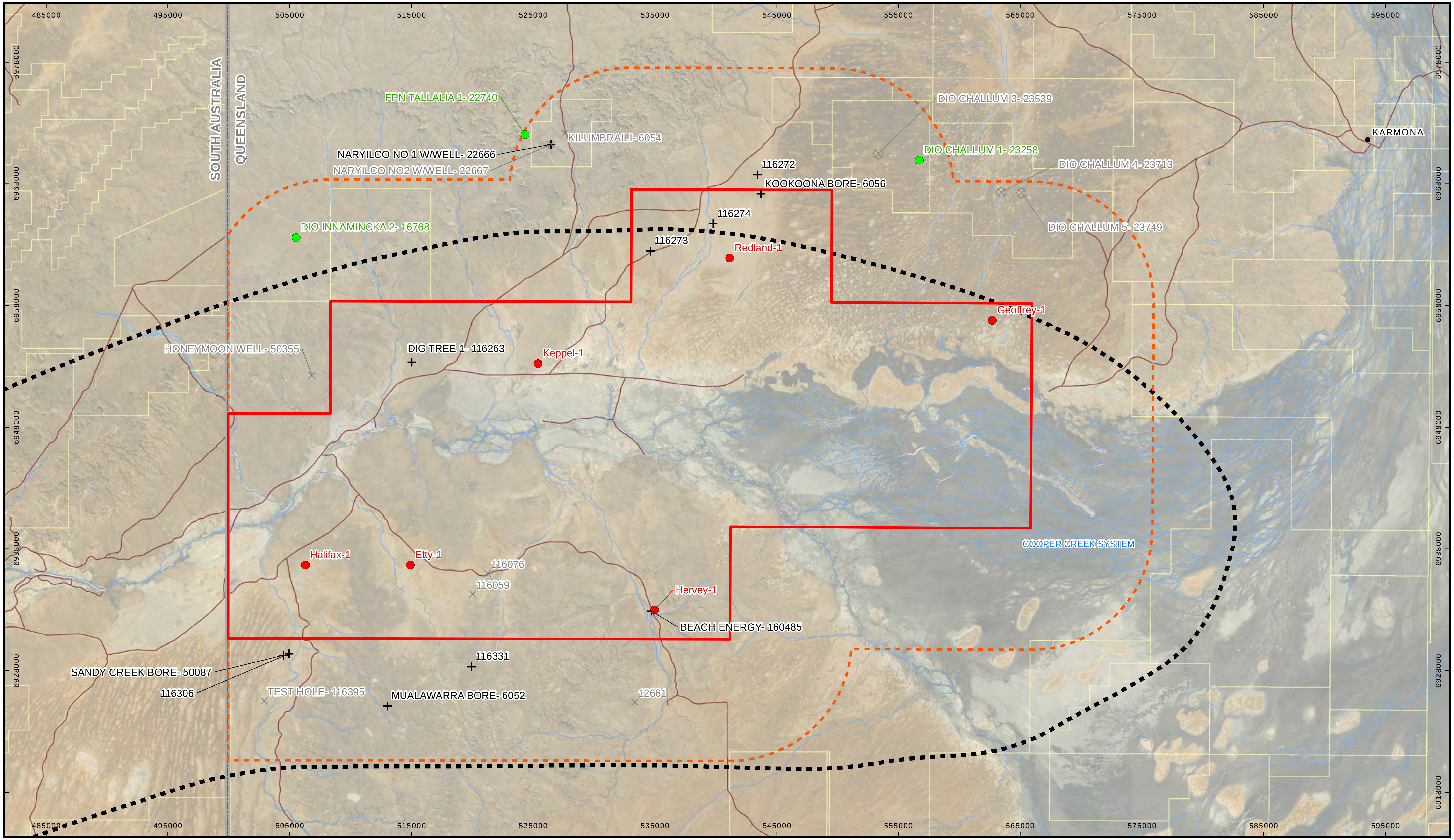
The Cooper Creek system is a vast, ephemeral, braided channel and floodplain system, forming the significant surface water feature in ATP 855. Flows originate due to sporadic occurrences of heavy rainfall over catchments in south-west Queensland. Typically, when flow events occur, most water flows south-westerly into the Ramsar-listed Coongie Lakes in South Australia. If flows are large enough to fill these lakes, additional water may flow down the main branch of Cooper Creek and eventually discharge into Lake Eyre in SA.

Significant local rainfall events can also result in shallow inundation of floodplains, inter-dune claypans and other areas of poorly drained impermeable soil, which can persist for days to weeks. Local rainfall and run-off can also result in short duration, low volume flow events in minor tributary ephemeral watercourses in this area that drain into the Cooper Creek system. For example, Hervey-1 is located adjacent to a small un-named watercourse, which sporadically flows into Milthaminnie Creek and ultimately into Cooper Creek.

The Santos EIR report (2003) cites Puckridge et al (1999), who analysed Cooper Creek stream gauge data at Cullyamurra (near Innamincka in SA), and identified that most of the flow (80% to 90%) is from its upstream catchment (i.e. there is very little flow contribution from local runoff). They also found that, while the Cooper typically flows every year (volumes ranging from 14,000 to 40,000 ML/a), several months usually pass without flow.

Groundwater in the region is generally very limited, with typically more than 5 metres depth to the sub-artesian water table. This indicates low potential for hydraulic connections between groundwater and surface water systems, other than ephemeral recharge during stream flow events. Water bores are very sparsely located across the lease area (Figure 9).

The nearest GAB springs to ATP 855 are part of the Yowah Creek spring complex, located more than 200 km to the south-east (Figure 10). The results of the most recent spring monitoring (State of Queensland, 2015, citing Negus et al 2015) confirmed that the Yowah Creek spring complex total extent in 2014 was about 2.5 ha, the same as in 2008 (towards the end of the "Millennium drought" period), but slightly less than the larger extent of 2.8 ha in 2011, which is interpreted as due to the very high rainfall over 2010-11.



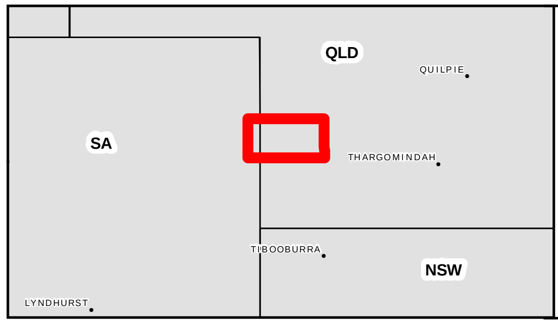
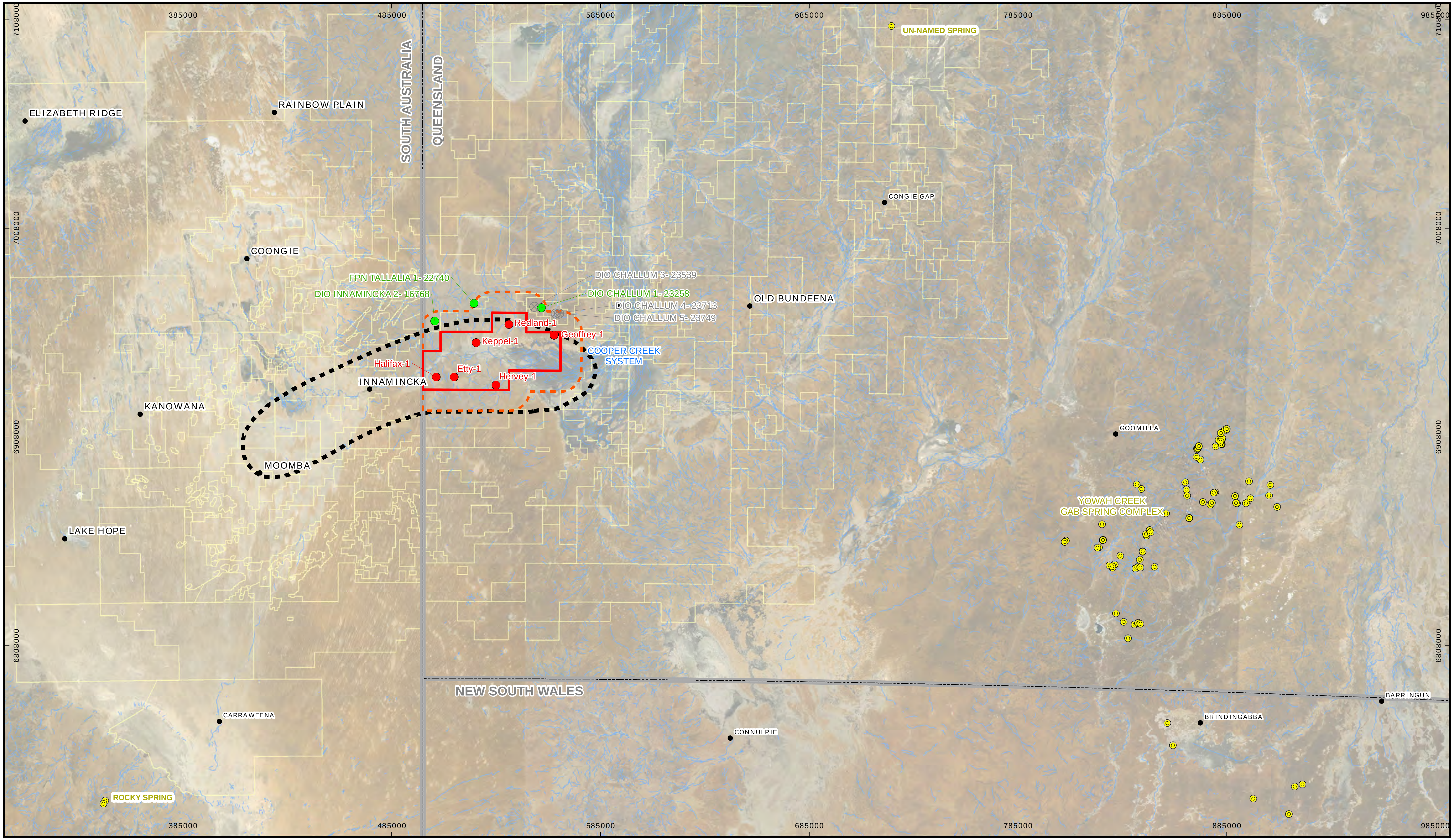
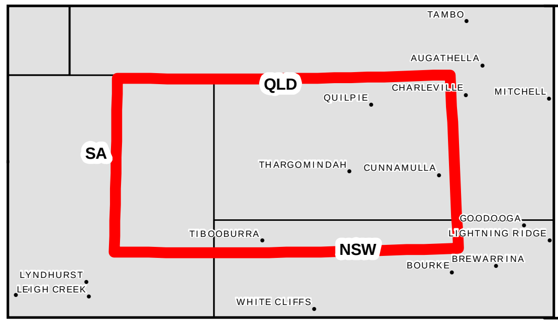


FIGURE 9

ATP 855 gas wells and water bores





N

20 0 20 40

Kilometres

APPROX SCALE 1:1,750,000 @ A3

GDA 1994 MGA Zone 54

DATA SOURCES
Hydrogeologic, Geoscience Australia

Disclaimer: While all reasonable care has been taken to ensure the information contained on this map is up to date and accurate, no guarantee is given that the information portrayed is free from error or omission. Please verify the accuracy of all information prior to use.

LEGEND

- Shale Gas Well
- GAB Bore
- Abandoned GAB Bore
- Locality
- Registered GAB Spring
- State Boundary
- Drainage
- ATP 855 boundary
- ATP 855 Buffer (10km)
- Petroleum Tenements
- Nappamerri Trough

hydrogeologic

FIGURE 10

ATP 855
Registered GAB Springs

The results of the most recent spring monitoring (State of Queensland, 2015, citing Negus et al 2015) noted that “the current method of monitoring springs by mapping the extent of permanent wetland vegetation has not been able to confirm whether flows to discharge springs are being protected because the contributions of groundwater flows to the changes in mapped extents have not been able to be identified.” In other words;

- the extents of the spring complexes are a useful analogue for spring health, showing a steady trend generally and measureable responses to the significant climatic variability over 2008-2011, with ongoing monitoring activities (State of Queensland, 2015)
- there is inadequate data on the spring discharge flows themselves and related aquifer pressures to establish a sound understanding about the flow contributions to springs and relationships with pressure conditions in GAB aquifers, but further investigations have been proposed (State of Queensland, 2015).

There are four operational sub-artesian bores (and two decommissioned bores) located within the ATP 855 lease area, but none of the (third party) operational water bores identified lie within a 3 km radius of any of the ATP 855 well sites drilled (Figure 9). There are six operational sub-artesian bores located outside the ATP 855 area itself but within 10 km of the northern boundary of ATP 855, and five decommissioned sub-artesian bores in that area.

There are no GAB bores located within the ATP 855 lease area, but there are three operational GAB bores located within 10 km of the northern boundary of ATP 855 (see Figure 9: RN16768, RN22740 and RN23258), along with three decommissioned GAB bores in that area.

3.2 Cooper / Eromanga Basin Overview

This information is taken from a range of published material (notably: Beach, 2012a; Middlemis, 2014) and additional unpublished data provided by Beach. The geology is described from deepest/oldest to shallowest/youngest, with references to the regional basin structure shown in Figure 11 and the stratigraphy shown in Figure 12.

Figure 11 - Regional Basin structure (after CSIRO, 2012c)

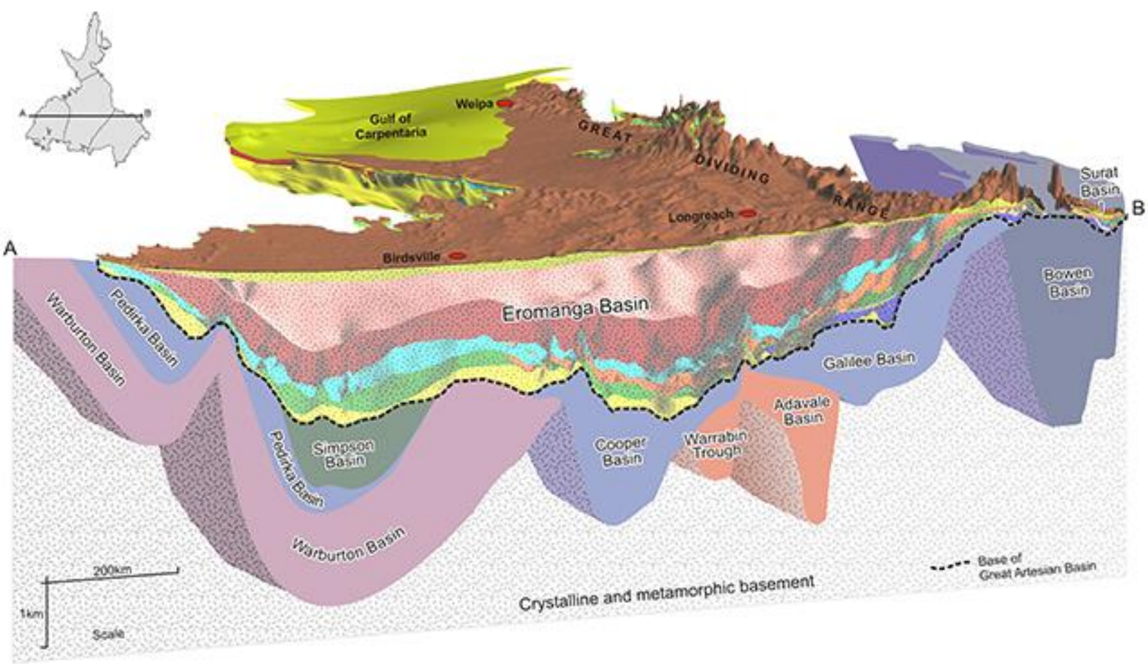
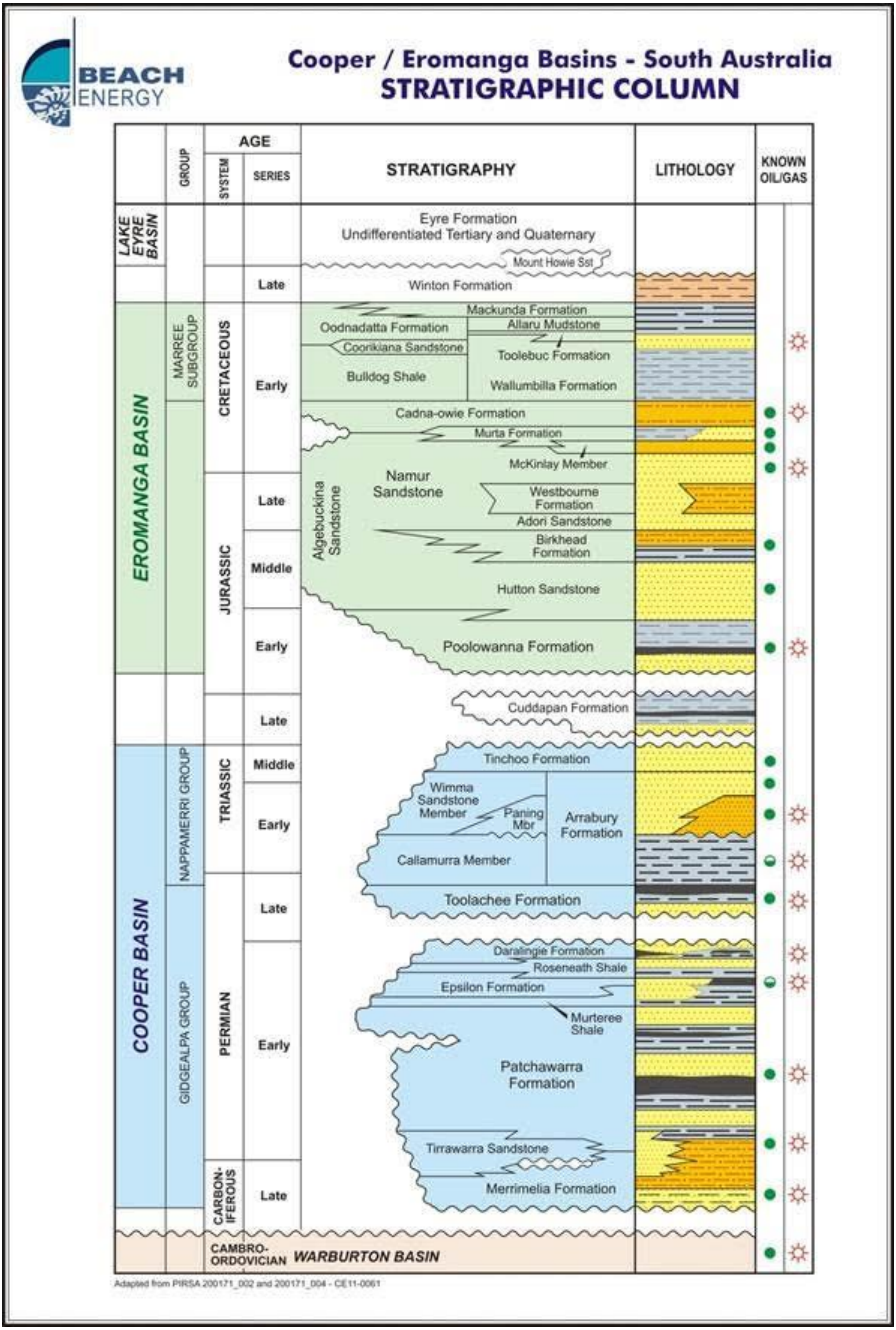


Figure 12 - Cooper Basin and Eromanga Basin stratigraphy



The Cooper Basin is a south-west to north-east trending basin that extends from north-east of South Australia into south-west Queensland (see Figure 11 and Figure 13). The Permian age Cooper Basin is underlain by pre-Permian basement and overlain (unconformably) by the Mesozoic age Eromanga Basin. The Cooper Basin sediments are characterised by fluvial, deltaic, and swamp deposits that include some coal measures. The sediments contain petroleum reservoirs (mainly gas) and some aquifers, with sediment accumulations exceeding 1,500 m thickness in some places. In the ATP 855 area, the Cooper Basin sediments are 600-750 m thick, to depths to about 4300 m.

The Nappamerri Trough is the deepest and largest of three south-west to north-east trending depocentres (sites where sediment has deposited and accumulated) within the Cooper Basin. The upper Cooper Basin sediments of the Nappamerri Group (Triassic) have substantial thickness in most places and form a major aquitard and regional seal (Figure 12) between the underlying Cooper Basin (Permian) sediments and the overlying Eromanga Basin (Jurassic-Cretaceous).

The Eromanga Basin unconformably overlies the Cooper Basin, and extends over a large area across parts of Queensland, New South Wales, South Australia and the south-east corner of the Northern Territory (Figure 11). The Mesozoic age Eromanga Basin sediments were deposited under fluvial (river), lacustrine (lake) and later shallow-marine conditions, and are broadly continuous across the Basin. These sediments are gently folded in some areas and contain a succession of geographically extensive sandstone formations that serve as oil reservoirs and as regional aquifers of the Great Artesian Basin (GAB).

The Eromanga Basin sediments in the ATP 855 area are typically around 600 m thick, to depths of 1700-2300 m. There are no GAB (artesian) bores located within the ATP 855 lease area, but there are three GAB bores within 10 km of its northern boundary (Figure 9).

The near-surface Cenozoic sediments of the Lake Eyre Basin consist generally of floodplains, wetlands, tablelands, gibbers and salt pans. However, at most sites within ATP 855, the Winton Formation (late Cretaceous, Eromanga Basin) is logged from near-surface (typically within 10 m), and comprises sandstones, siltstones, claystones and shales and thicknesses of up to 900 m. The Winton Formation is targeted by sub-artesian bores for the purpose of stock and domestic water supplies, and for industrial purposes to support oil and gas drilling activities (Figure 9). The 65 m deep Halifax water bore is completed into the Winton Formation.

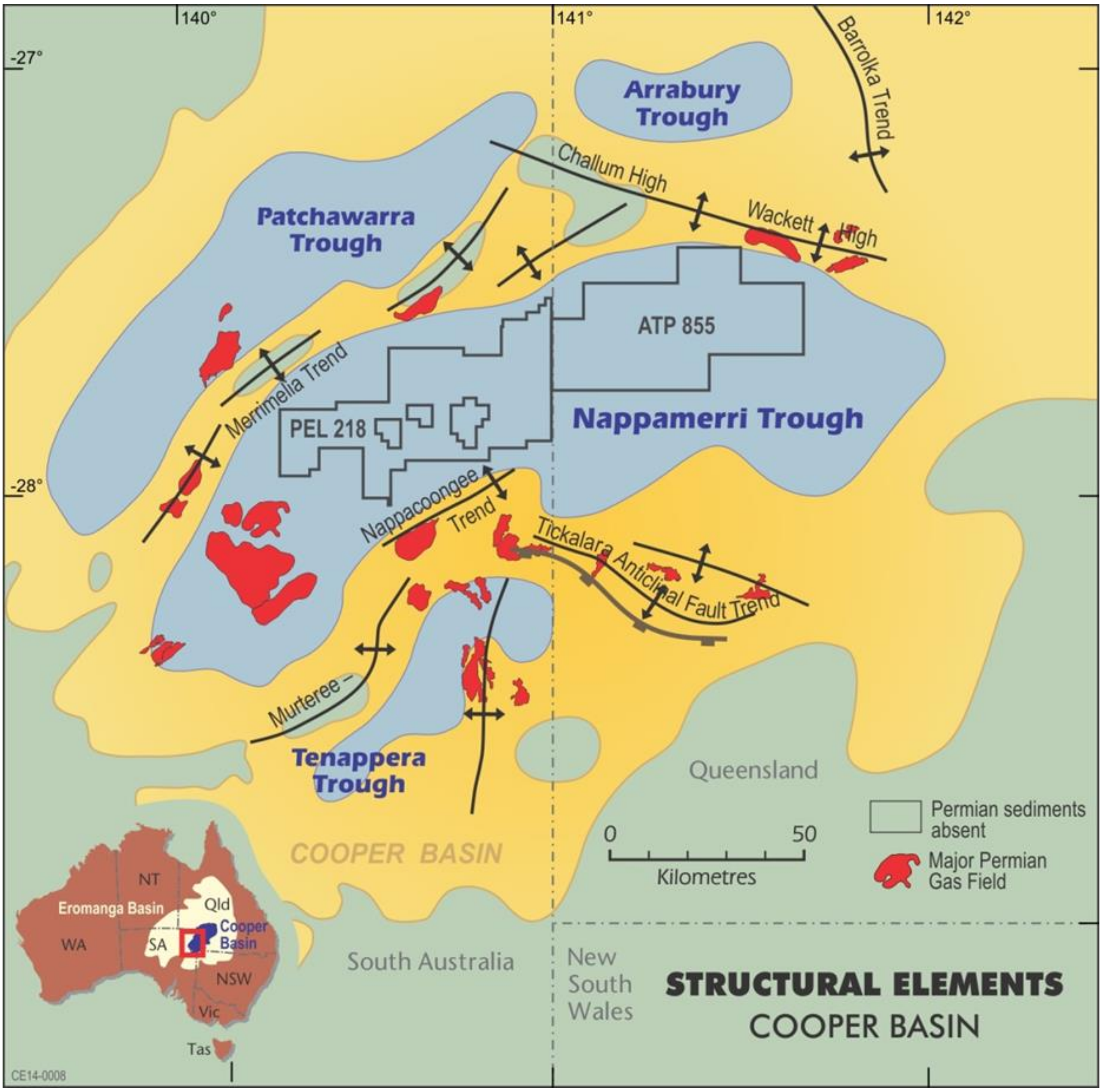
3.3 Nappamerri Trough Overview

The information in this section is taken largely from Trembath, Elliot and Pitkin (2012). The Nappamerri Trough is the deepest and largest of three southwest-northeast trending depocentres within the Late Carboniferous to Middle Triassic aged Cooper Basin (Figure 13). The Nappamerri Trough contains a thick Permian-Triassic section of sandstones, coals, siltstones and shales deposited in a cold climate fluvio-lacustrine setting. Changes in depositional environments between fluvial, lacustrine and deltaic have resulted in stacked multiple targets within a proven hydrocarbon province. Extensive drilling in the southwest portion and on the flanks of the trough proved up many commercial Permian gas fields.

The Permian age units of the Roseneath Shale, Epsilon Formation and Murteree Shale (REM package – see Figure 12) were initially the focus of shale gas assessment in the Nappamerri Trough. The thick shale units of the Roseneath and Murteree are considered regional seals (in addition to the major regional seal formed by the Triassic Nappamerri Group of the upper Cooper Basin). The main source units for the Cooper Basin were thought to be the coals and organically rich shales within the Patchawarra and Toolachee Formations; however, more recent geochemical investigations reveal that both the Roseneath and Murteree Shales have also been a significant source of hydrocarbons within the Nappamerri Trough. World-wide, there are no pre-existing analogues for the Nappamerri Trough shale play because all of the commercially produced shale gas plays in North America involve marine rather than lacustrine shales.

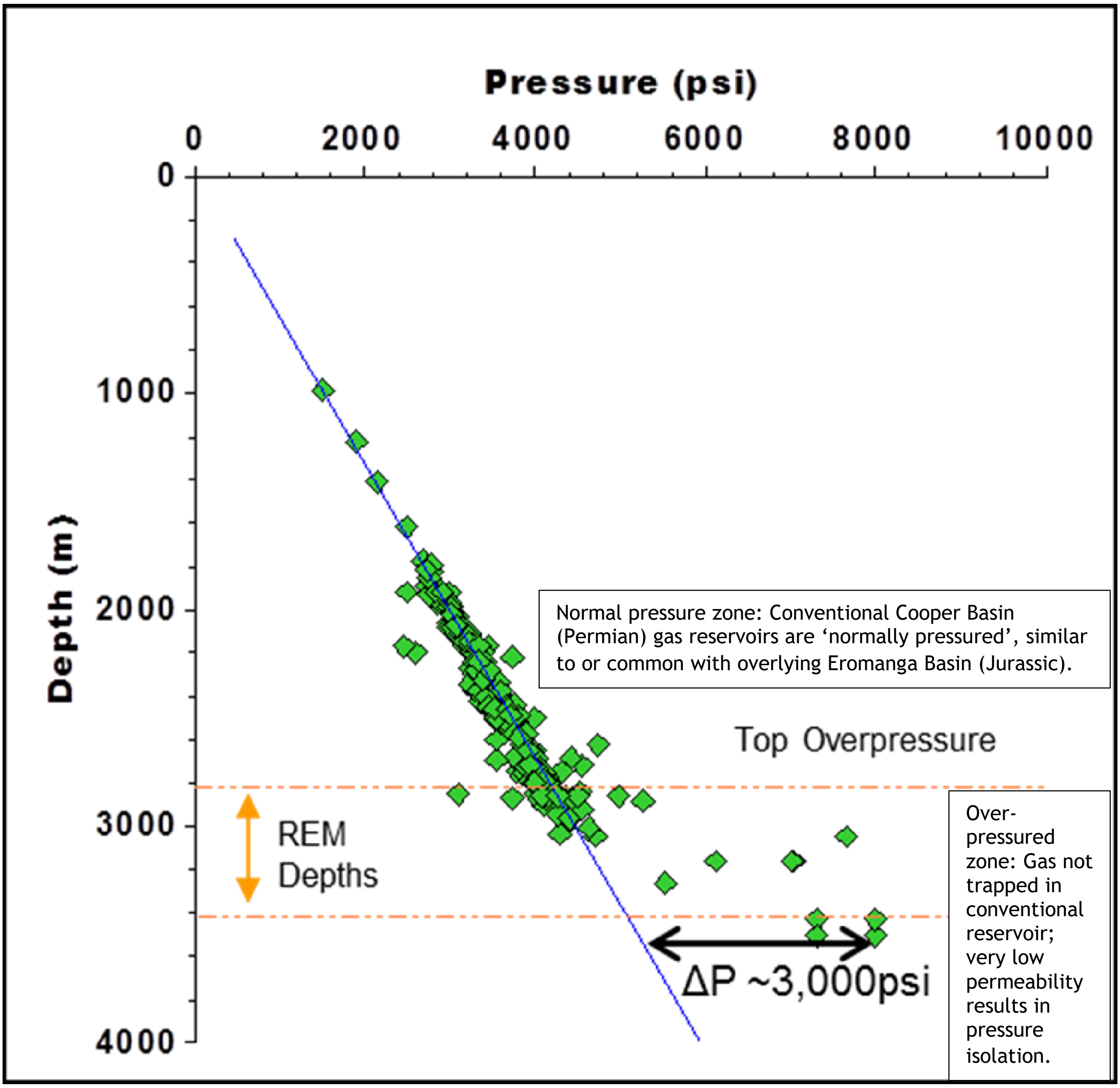
The historical exploration wells intersected gas saturated, low permeability sandstones within the Epsilon and Patchawarra Formations. Gravestock et al (1998) indicate Patchawarra Formation permeability typically in the order of 1 to 10 mD (roughly 0.001 to 0.01 m/day) and rarely exceeding 100 mD, representing aquitard properties in hydrogeological terms. Although many drill stem tests (DSTs) were conducted in these wells, there was no evidence of formation water being produced and gas-water contacts were not identified from pressure or log data. The potential was recognised for the Nappamerri Trough to represent a large basin centred gas play with the low permeability, over-pressured sandstones, as well as the REM shale gas play.

Figure 13 – Major structural geological elements of the Nappamerri Trough and Cooper Basin



The DSTs and mud weights also indicate that the Epsilon and Patchawarra Formations are over-pressured and that the over-pressure is confined to the Nappamerri Trough. The regional pressure gradient is 0.43 psi/ft, while the pressure gradient in Nappamerri Trough, based on DST information over the Epsilon and Patchawarra Formation, is about 0.72 psi/ft (Figure 14).

Figure 14 - Nappamerri Trough over-pressured character



The extent of over-pressure in the Nappamerri Trough covers almost all of the ATP 855 area (Figure 15). The over-pressure character indicates that it is not in hydrodynamic connection with other regional aquifers (e.g. the GAB system), and that the permeability is sufficiently low to trap the gas accumulations (i.e. in the absence of structural features). The very low permeability formations require fracture stimulation for gas production. The wells are pressure tested prior to commencing fracture stimulation, to confirm the integrity of the casing and cement.

Figure 16 shows a cross-section through the Nappamerri Trough (from SA into QLD), indicating the locations of the wells drilled in ATP 855 and the rough locations of the stimulation treatments. It also shows the relationships of the Permian Cooper Basin sediments to the regional seal (aquitard) of the Triassic Nappamerri Group and the overlying Jurassic to Cretaceous sediments of the Eromanga Basin.

Figure 15 - Nappamerri Trough – area of over-pressured character

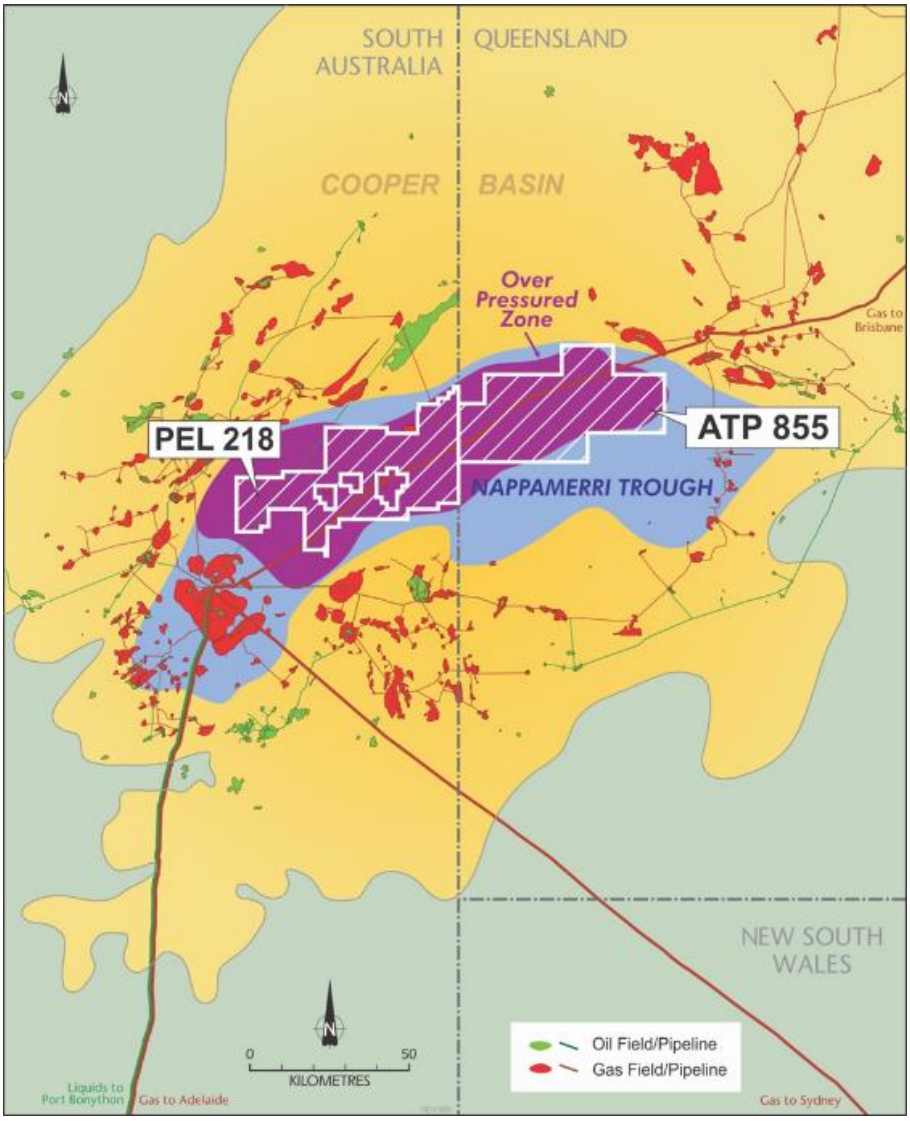
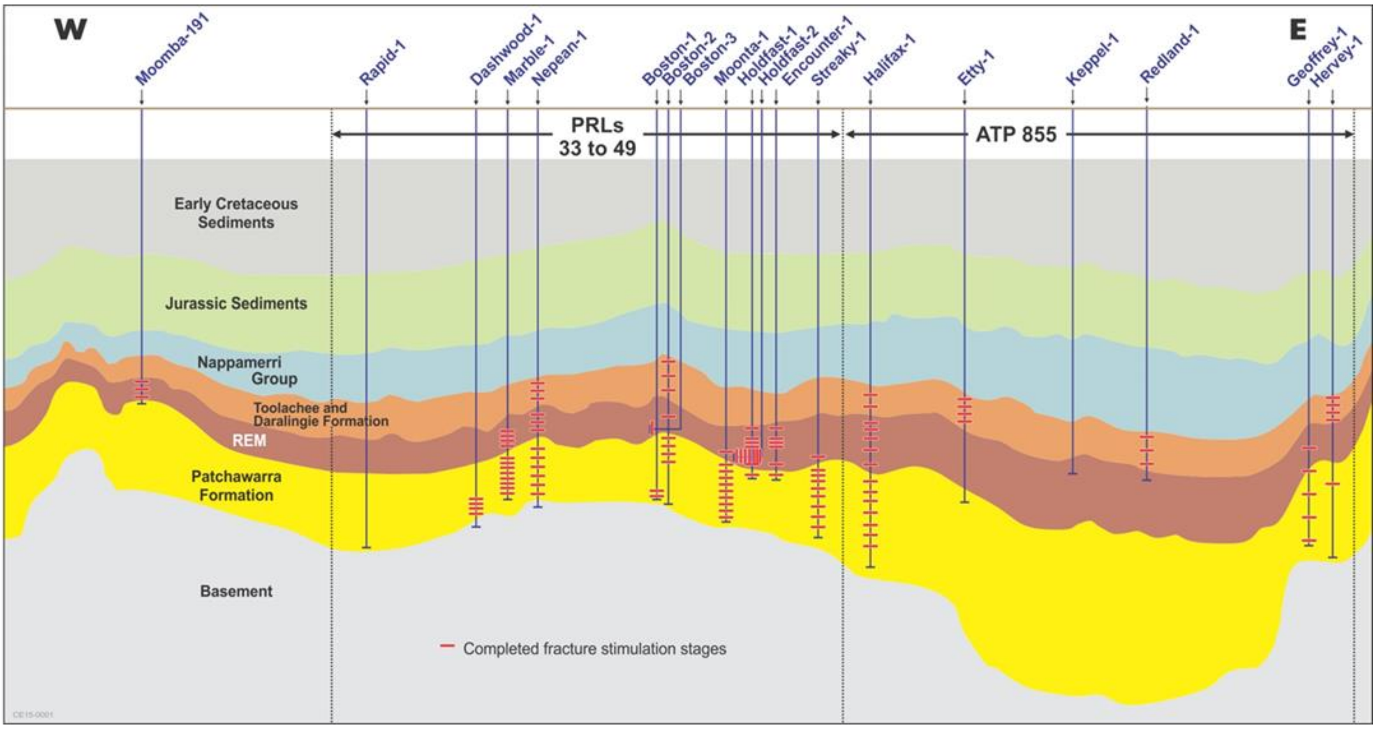


Figure 16 - Section through Nappamerri Trough showing ATP 855 wells and stimulated units



3.4 Great Artesian Basin (GAB) Overview

Much of this information is drawn from CSIRO studies (2012). The Great Artesian Basin is a complex, geographically extensive system comprising multiple aquifers within a number of geological basins and sub-basins. It consists of alternating layers of water-bearing (permeable) sandstone aquifers and non-water-bearing (impermeable) siltstones and mudstones. The overlying impermeable rocks confine the aquifers and cause the groundwater to be pressurised. Although artesian conditions exist across most of the Basin, sub-artesian conditions exist on the edges of the Basin and in some other areas of higher elevation.

The aquifers of the Basin are recharged by infiltration of rainfall and leakage from streams into sandstone outcrops located mainly along the western slopes of the Great Dividing Range. Groundwater flows under gravity generally to the west and south-west towards springs, some of which are located at great distances from the recharge areas. In the north of the Basin, it flows to the north and north-west. Groundwater moves slowly through the Basin, typically at rates in the order of 1 to 2 metres per year, and much slower in the depocentre (the project area).

Across the Eromanga Basin, the major GAB confined aquifer and aquitard systems are identified (CSIRO, 2012b) as the following, from shallow to deep:

- the “Upper Confined Aquifer (Cretaceous)” sediments of the Winton and Mackunda Formations (generally confined by the clays and shales of the Winton Formation itself and the overlying sediments of the Lake Eyre Basin) – the “upper GAB aquifer system”
- the intervening “Main Aquitard (Cretaceous)” units of the Wallumbilla Formation (Bulldog Shale and Oodnadatta Formation in SA)
- the “Main Confined Aquifer (Lower Cretaceous-Jurassic)” sediments of the Cadna-owie Formation and the Hutton Sandstone – the “main confined GAB aquifer system” (generally underlain by the Nappamerri Group aquitard and regional seal).

The upper GAB aquifer system is not artesian and is not as widely utilised as the deeper and better quality artesian aquifers of the main confined GAB aquifer system. To the east of the Birdsville Track Ridge, the Central Eromanga Basin overlies the Cooper Basin in the ATP 855 area. The main confined GAB aquifer units in this area are the Cadna-owie Formation and the Hutton Sandstone. Other units in the package include the Murta Formation (aquitard), Namur Sandstone, Westbourne Formation (aquitard), Adori Sandstone and Birkhead Formation.

An analysis of porosity and permeability data contained within the Petroleum Exploration and Production System (South Australia) and the Queensland Petroleum Exploration databases has been undertaken by CSIRO (2012a) for the Central Eromanga region (Table 4).

The CSIRO study (2012a,b; summarised in Table 4) concluded that the geological formations that contain GAB aquifers have average permeability values between 100 and 1000 mD (roughly 0.1 to 1 m/d in aquifer terms), with a few measurements below 10 mD. These are low values for an aquifer, equivalent to about 0.1 to 1 m per year of advective horizontal groundwater movement (CSIRO 2012b). These permeability characteristics would be “better described as an aquitard” (CSIRO, 2012b), and Table 4 bears this out, showing little material difference in the mean permeability for units that are classified as either nominal aquifers or aquitards. For example, the upper Wyandra Sandstone member of the Cadna-owie is identified in regional terms as a nominal aquifer (CSIRO 2012b), but in some areas of the Eromanga Basin, explorers and producers have encountered serious difficulty trying to recover water or oil from the Cadna-owie.

Aquifer storage coefficient information is limited. Storage coefficients calculated from petroleum well log data and independently from bore testing range from $1x10^{-4}$ to $1x10^{-5}$ (GABCC, 2010), which is at the low end of the expected range for a productive aquifer.

Table 4 - Porosity and permeability of GAB units in Central Eromanga Basin (CSIRO, 2012a)

Formation	Number of porosity measurements	Mean Porosity (%)	Number of permeability measurements	Mean horizontal permeability (mD)	Hydrogeological classification
Cadna-owie Formation	405	15	331	96	leaky aquitard
Hooray Sandstone	4438	16	4222	131	aquifer
Westbourne Formation	951	14	896	105	leaky aquitard
Adori Sandstone	64	22	71	813	aquifer
Birkhead Formation	1578	14	1348	130	partial aquifer
Hutton Sandstone	2928	17	2687	452	aquifer

Note: mD = milliDarcy. Darcy is the fundamental unit for intrinsic permeability, and 1 Darcy is 9.869233×10^{-13} m^2 (sic, IESC 2014). For typical GAB aquifers, 100 mD translates to an equivalent aquifer hydraulic conductivity of about 0.1 m/d (IESC, 2014), which is better characterised as an aquitard rather than a productive aquifer (CSIRO, 2012b).

Experienced judgment from the region indicates typical GAB bore yields of about 10 L/s, with salinity usually less than 2000 mg/L TDS. Information from Muller (1989) allows the following summary of the main water quality parameters in the Cadna-owie-Hooray aquifer (Main Confined Aquifer (Lower Cretaceous-Jurassic)):

- Salinity: average TDS in the range 1000 to 1500 mg/L (maximum 2000 to 4000 mg/L)
- Total Hardness (as CaCO3): average 20 to 50 mg/L (maximum up to 200 mg/L)
- Total Alkalinity (as CaCO3): average 500 to 1000 mg/L (maximum up to 2000 mg/L)
- Bicarbonate: average 700 to 1100 mg/L (maximum 1500 to 2000 mg/L)
- Carbonate: average 15 mg/L (maximum up to 65 mg/L).

GAB water quality is generally not suitable for irrigation due to a sodium adsorption ratio issue related to the water being chemically incompatible with the dominantly montmorillonitic swelling clay soils over much of the GAB (GABCC, 2010).

3.5 Shallow Aquifer Systems Overview

For the purposes of this study, shallow aquifer systems cover the package of units overlying the GAB aquifers, generally less than 500 m depth, consistent with the CSIRO (2012b) definition of “Upper Confined Aquifer (Cretaceous)” or “upper GAB aquifer system”, along with the overlying and near-surface Cenozoic age sediments of the Lake Eyre Basin.

These shallow units comprise generally poorly consolidated to consolidated Tertiary to upper Cretaceous age units of sandstone, siltstone and mudstone, with some calcareous units (and with some overlying unconsolidated Quaternary age units providing limited aquifer targets). The Tertiary to upper Cretaceous units are thickest and most prospective in the area of the main drainage lines such as Cooper Creek. These formations are recharged mostly from leakage from episodic flow events in the surface streams. Localised aquifers can also be found in Quaternary alluvial sands and gravel.

While there are few sub-artesian bores in the ATP 855 area (Figure 9), many bores have been drilled into these units in other areas, often to provide stock and domestic supplies, and more recently for oil and gas developments. Records show that most shallow bores are less than 500 m deep, often with yields of 2 to 5 L/s, in some cases less, especially where close to Cooper Creek. In some cases, shallow bore yields are reported in the order of 10 to 15 L/s, notably at the western end of the

Nappamerri Trough around Moomba in South Australia. Salinity records are sparse, but are typically the shallow aquifer salinity lies in the 10,000 to 20,000 mg/L TDS range, especially for bores less than 500 m deep, although there are also some areas where salinity is less than 10,000 mg/L.

Information from Muller (1989) allows the following summary of other water quality parameters in the shallow (non-GAB) aquifers:

- Total Hardness: (as CaCO3) typically 500 mg/L (maximum over 4000 mg/L)
- Total Alkalinity: (as CaCO3) typically 200 mg/L (maximum over 500 mg/L)
- Bicarbonate: typically 200 mg/L (maximum over 500 mg/L)
- Carbonate: typically <10 mg/L (maximum over 30 mg/L).

The Halifax sub-artesian water bore is distant from Cooper Creek, drilled to 65 m depth in the Winton Formation, and exhibits a salinity of around 12,000 mg/L. Although the Halifax bore is shallow, it is completed in the Winton Formation, which is late Cretaceous age. The Halifax bore is thus completed in the sub-artesian part of the upper GAB aquifer system (see section 3.4 for GAB aquifer definitions), and should not be confused with the younger, near-surface Cenozoic age (Tertiary-Quaternary) Lake Eyre Basin formations. A total volume of 68 ML has been extracted from the Halifax water bore to support fracture stimulation operations in ATP 855 over the period from January 2013 to January 2015.

3.6 Groundwater Flow System Characteristics

3.6.1 Cooper and GAB Underground Water Level Trends

There is almost no hydrogeological information currently available on the properties of the Cooper Basin aquifer and aquitard units, mainly due to the drilling depth and cost involved, and the lower yield and brackish to saline water quality.

In terms of water quality, analyses for several ATP 855 wells from flowback after stimulation (which are affected by the stimulation fluids and thus are not representative of the Cooper Basin) indicate a salinity of 6,000-7,000 mg/L and pH of 7.6 to 7.8.

While there is a Bioregional Assessment study in progress (funded by the Federal Government) that will improve hydrogeological understanding (bioregionalassessments.gov.au/bioregions/leb.shtml), most hydrogeological information in the ATP 855 area currently relates to the Eromanga Basin (e.g. from the 2012 CSIRO studies). This is due to the importance, quality and accessibility of the GAB groundwater system compared to the effectively undeveloped Cooper Basin (in groundwater terms).

Available information on the GAB flow system is taken from the 2012 CSIRO study, which concluded that significant regional groundwater flow in the GAB is limited to areas adjoining the recharge zones where the aquifer has shallow burial (i.e. remote from the Central Eromanga Basin and the ATP 855 project area).

The deeper regions of the GAB (the project area) have very low flow and are characterised as "relatively stagnant" (flow velocities of 0.03 to 0.3 m per year) in contrast to the moderate velocities of 1.2 to 2.5 m per year for younger waters on the margins of the basin.

This is illustrated in Figure 17 (after CSIRO 2012b, Figure 8.9), which shows very little through-flow in the project region of the Eromanga depocentre overlying the Cooper Basin (the dark blue area). The yellow to orange shading on the flow arrows indicate increasing salinity along the southern flow path in the project area. There is an unquantified component of upward leakage from the underlying Cooper Basin contributing to through-flow in the Eromanga system (CSIRO, 2012b).

Figure 17 - 3D view of GAB showing principal flow paths relatively stagnant in depocentre above Cooper Basin (after CSIRO 2012b, Figure 8.9)

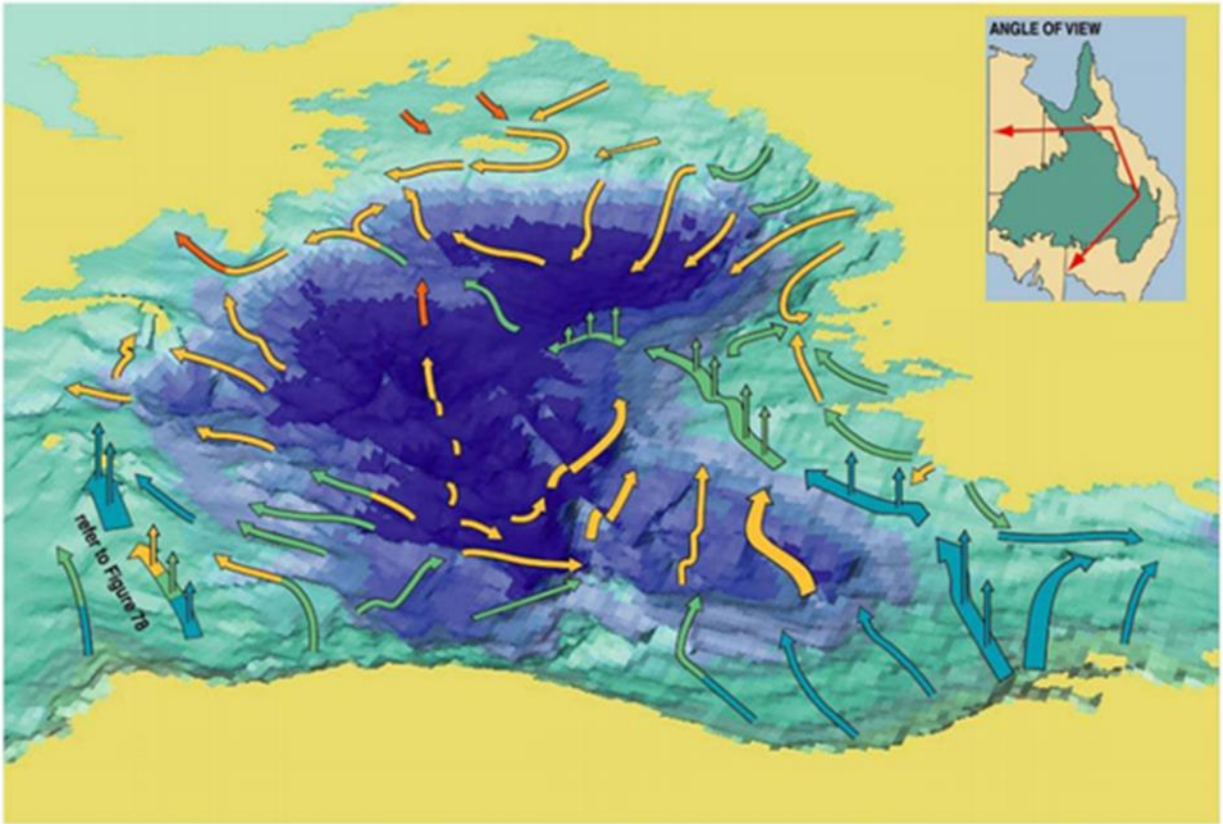


Figure 8.9 Reduced groundwater flow (thick to thin arrows), leakage (vertical arrows) and increased salinity (blue to red colours) depict the hydrodynamics of the Cadna-owie – Hooray aquifers of the Great Artesian Basin (from Radke et al., 2000)

The latest Minister's statement (State of Queensland, 2015) includes this summary information on artesian and sub-artesian aquifer systems of the GAB:

- "The hydrographs from monitored **artesian bores** in most plan aquifers indicate that groundwater pressure appears to be stable or rising" (except for the Surat, Surat East, or Surat North management areas); the "implications of these trends are yet to be fully understood and more detailed analysis of the pressure data will be undertaken during 2015 via a hydrogeological study that will inform the preparation of the new plan."
- "Stable or rising groundwater pressure trends suggest that in the majority of plan aquifers, the reliability of water supply is being maintained and protected. The capping of more than 676 uncontrolled bores to date through programs such as the Great Artesian Basin Sustainability Initiative (GABSI) is facilitating the recovery of groundwater pressure across plan aquifers."
- "There are no obvious trends in the water levels in **subartesian aquifers**; however, there may be some climatic influences. The hydrogeological study will also make a detailed examination of the water level data."

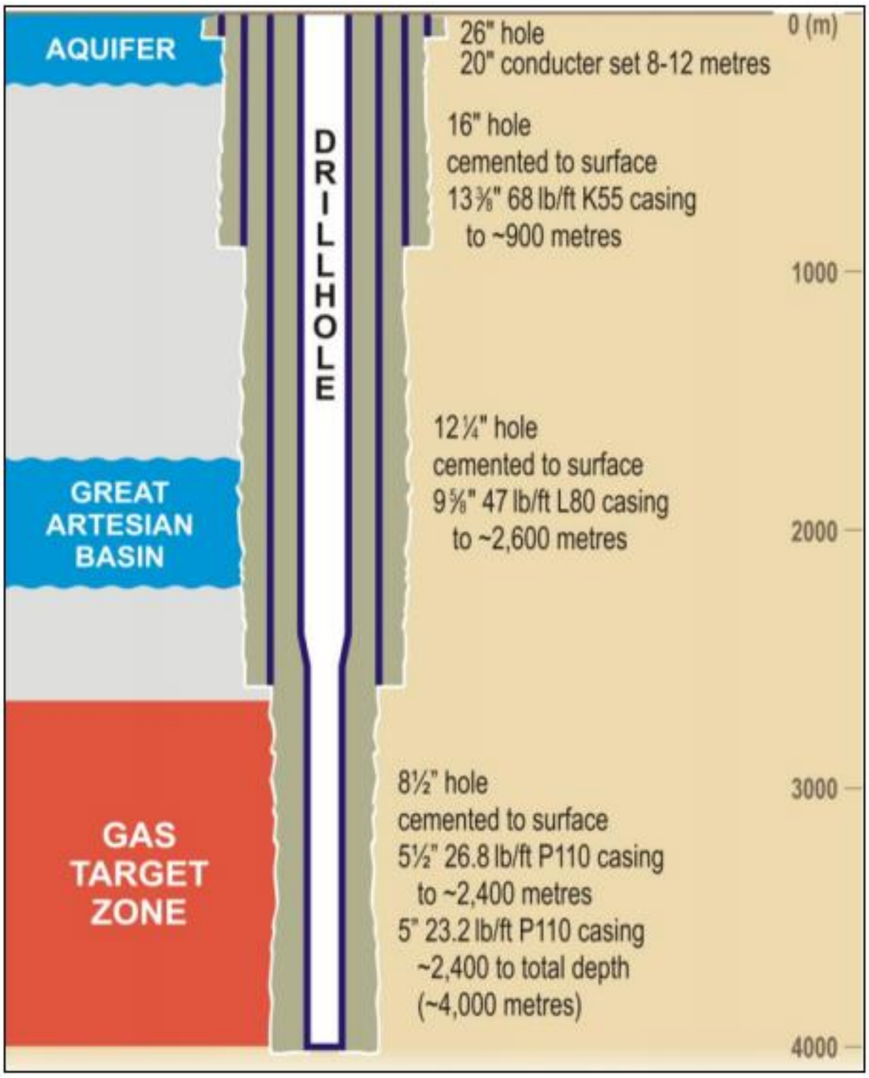
3.6.2 NTNG Fracture Stimulation and Production Testing in ATP 855

3.6.2.1 NTNG Well Design

Beach Energy's current well design schematic for the vertical exploration wells in ATP 855 is shown in Figure 18. The multiple layers of casing with pressure cement grouting to the surface are designed to control any potential for inter-formation connectivity:

- the conductor pipe is installed at the surface to provide the initial stable structural foundation for the well.
- the surface casing string extends from the surface to about 900 m.
- the intermediate casing string is constructed inside the surface casing and extends from the surface to more than 2400 m, past the base level of the Great Artesian Basin aquifer
- the production casing string is constructed inside the intermediate casing and runs from the surface to the total depth of the well.

Figure 18 - Beach gas well design schematic



3.6.3 Fracture Stimulation Additives

The overall percentages of additives in a typical fracturing operation on a deep shale gas well in the Cooper Basin are shown in Figure 19 (after Beach, 2012a).

Figure 19 - Additive components in a typical fracturing operation on a deep shale gas well in the Cooper Basin (Beach 2012a, Figure 21)

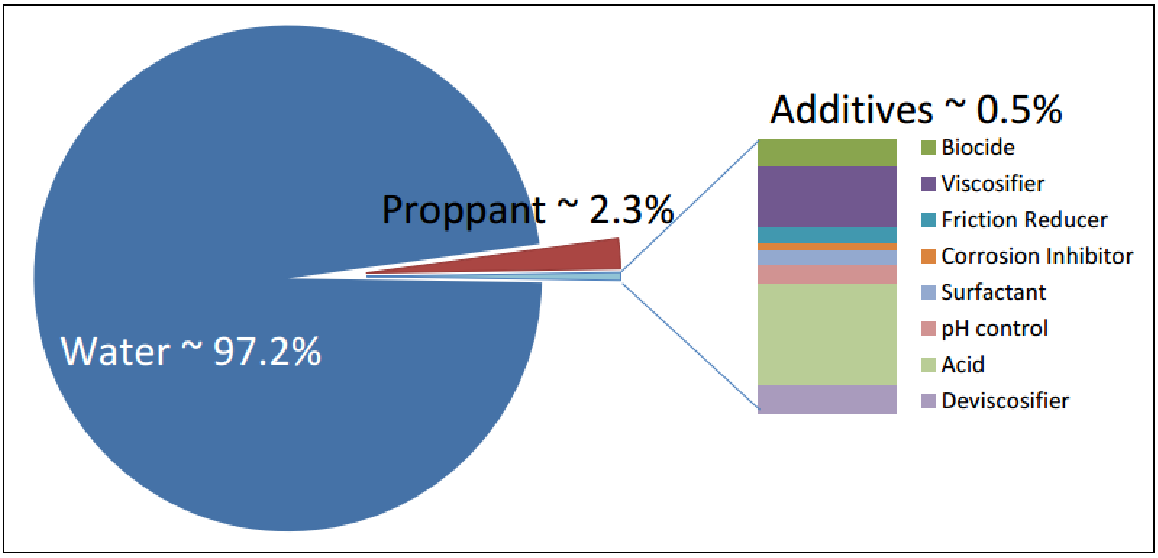


Figure 21: Example of overall percentages of additives in a deep shale gas well fracturing operation in the Cooper Basin (based on data from fracture stimulation of the Holdfast-1 well)

Water is the main component of fracture stimulation treatments and forms the vast majority of the fluid injected during fracturing operations, typically around 97%, with proppant the next largest constituent. Proppant is a granular material (typically sand or small ceramic beads are used in the Nappamerri Trough where additional strength is required due to the great depth and high pressures), which is mixed in with the fracturing fluids to prop open the fractures and allow gas to flow to the well.

In addition to water and proppant, a range of other additives are necessary to ensure successful fracture stimulation. Chemical additives include acid, buffers, biocides, surfactants, iron control agents, corrosion and scale inhibitors, cross linkers, friction reducers, gelling agents and gel breakers. Several of these ingredients are essential to maintaining well integrity.

3.6.4 Fracture Stimulation Diagnostics

A range of diagnostics was run during the fracture stimulation operations for a range of purposes (Scott Delaney, Beach Energy, pers.comm.), summarised in Table 5.

Table 5 - Summary of Diagnostics applied to ATP 855 wells

Well	Surface Micro-seismic	DFIT	Chemical Tracers	Radio-active Tracers	Production Logging	Gas Sampling	Water Sampling
Halifax-1	-	-	-	-	✓	✓	✓
Hervey-1	✓	✓	✓	-	✓	✓	✓
Etty-1	✓	✓	✓	✓	✓	✓	✓
Redland-1	✓	✓	✓	✓	-	✓	✓
Geoffrey-1	✓	-	✓	✓	✓	✓	✓

3.6.4.1 Surface Micro-Seismic Mapping

Surface micro-seismic mapping monitors fracture growth, azimuth, stimulated rock volume and propped stimulated rock volume. It involves placing a sensitive set of listening devices (geophones) at the surface during the stimulation of the target well. During stimulation, small movements of rocks are detected at the monitoring well and the location of those movements is determined by triangulation.

The technique is accurate enough to assist geologists and engineers to understand such things as the height of fracture growth of a treatment and whether the fracture treatment is breaking new rock or has grown back into a previously placed fracture treatment (Beach 2012a).

Mapping the extent of the fracture treatment also aids in understanding how much of the rock may be connected back to the well bore, which in turn assists in assessing the potential quantity of gas that might be drained by the well. It also helps in determining the distance required between wells to maximise stimulation of the rock and increase recovery of the gas.

Prior to using surface micro-seismic at ATP 855, the chance of success for the technology was considered low due to the target depth and the presence of Toolachee coals at the top of the interval that were expected to absorb the signal. The expected chance of success was even lower in sandstone than shale as sands were expected to produce lower magnitude events. However, all surveys recorded a significant number of events and were operationally successful.

The geophones in ATP855 were trenched where geographically possible to minimise the noise, however there was no clear difference in the noise observed at the trenched locations compared to the surface locations.

The three surveys in ATP 855 had consistent induced fracture azimuths (NW/SE as expected, see Figure 20) and the event moment magnitude was generally between -2.5 and -1.5 (Figure 21), well under the range human perception in the Modified Mercali Scale. A magnitude of about +2 is roughly equivalent to the barely perceptible effect that might be felt by someone sitting inside a house when a large truck drives past on a road outside (Sherburn and Quinn, 2012).

Figure 20 - ATP855 Micro-Seismic Event Azimuth

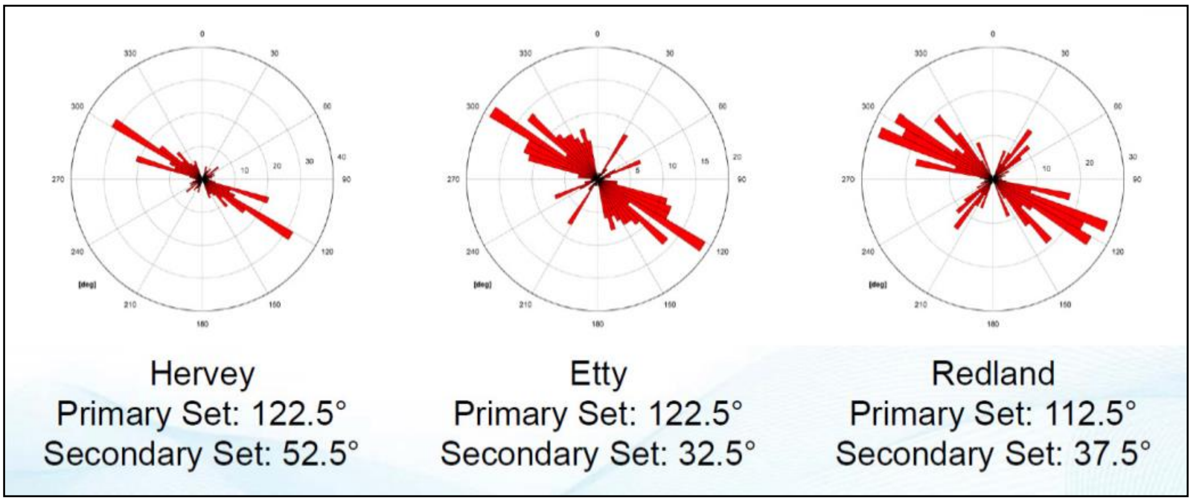
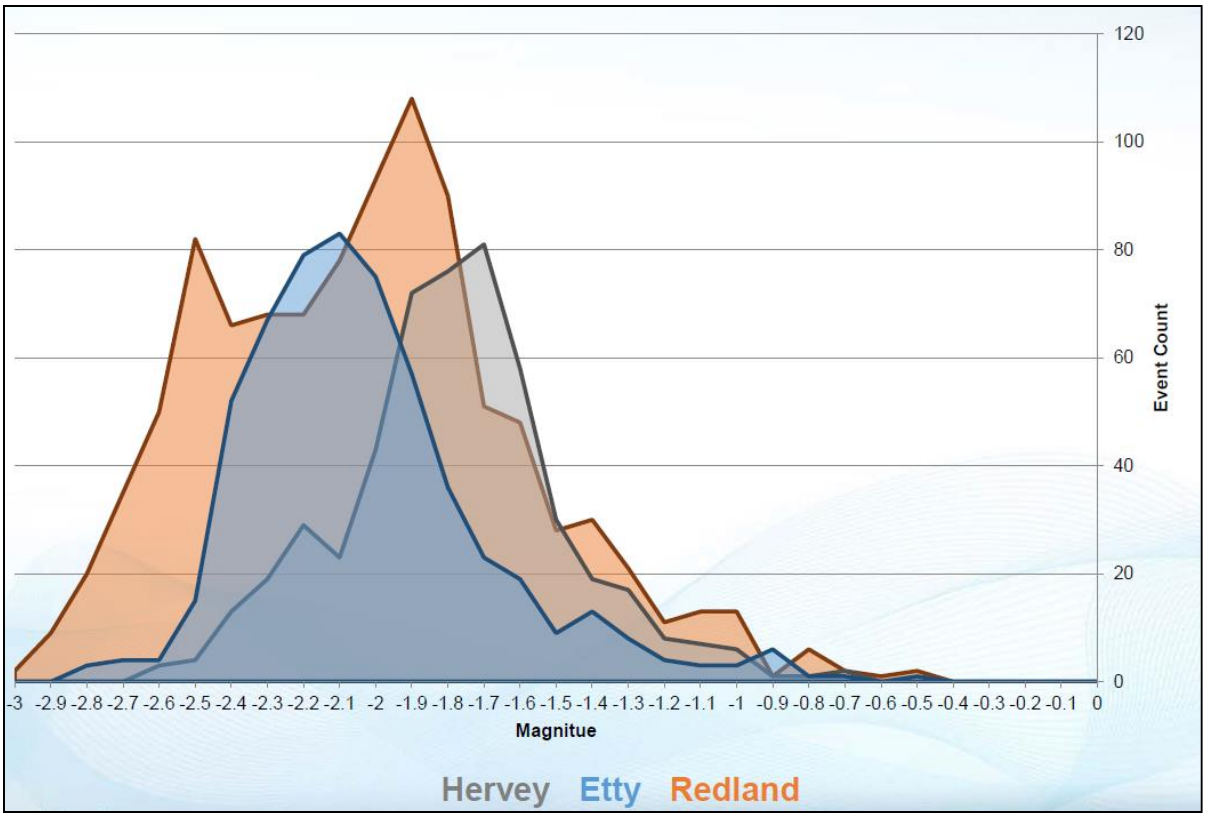


Figure 21 - ATP855 Micro-Seismic Event Magnitude



3.6.4.2 DFIT

Diagnostic Fracture Injection Testing is also referred to as a "pre-frac", "mini-frac", "mini fall-off" or "datafrac". A DFIT involves a precursory very low volume injection or fracture stimulation without proppants, and a subsequent shut-in and then recovery monitoring ("fall-off") test. It is used to determine the fracture closure pressure (or minimum in-situ stress), the formation permeability, and provide estimates for fluid efficiency, fluid leak-off coefficient, fracture gradient and other key calibration parameters.

DFITs were conducted pre-stimulation in Hervey-1, Etty-1 and Redland-1, and the test provided results on minimum horizontal stress, formation permeability and reservoir pressure.

3.6.4.3 Chemical Tracers

Non-hazardous chemical tracers may be added in very low concentrations to each of the fracture stimulation stages to assist with understanding which zones are contributing to flow back after the treatments ("splits", or portions of traced versus untraced fluid). The information is also used to optimise future stimulation design.

Concentrations of the tracer injected into each stage are of the order of 750 parts per billion. However, on flowback, as some of the tracer remains underground, total concentrations of tracers recovered is typically less than 250 parts per billion, and usually comprised of 0-100 parts per billion from each of the stimulation stages.

Chemical tracers were used on most wells as they were a simple diagnostic that did not require wellbore intervention, and due to casing deformation it was often the only diagnostic data collected.

While there appears to be a correlation between low tracer recovery and good gas production, there are concerns on tracer decay and interaction of the tracer with the formation water. For example, while untraced fluid volumes recovered in Etty-1 and Geoffrey-1 would suggest some formation water contribution, there is doubt due to the impact of tracer decay. Further investigation into the tracer stability and interaction with the formation is required.

3.6.4.4 Radioactive Tracers

Radioactive Tracers are components of the proppant that are tagged with Scandium, Iridium and/or Antimony that are used to identify fracture height growth near the wellbore. A gamma ray geophysical tool was run post-frac to identify where the tracer-tagged proppants are placed. Published radioactive tracer data across the Cooper Basin suggested that induced fractures were extremely well contained.

Radioactive tracer diagnostics were run post-frac at Etty-1, Redland-1 and Geoffrey-1 to improve the understanding of the effectiveness of fracture stimulation of clusters of perforations and assist in confirming where proppant was placed. These aspects are important in understanding post-stimulation flow performance and optimising perforation and stimulation design in future wells.

Etty-1 and Geoffrey-1 were the only wells that collected good radioactive tracer data. The tracer data was of most use identifying which clusters of perforations were stimulated.

The height growth data was very constrained, in line with expectations. It also confirmed that the cement bond was competent around the stimulated intervals.

Computer based model simulations populated with stress data estimated from observed rock parameters were unable to model the limited height growth in induced fractures shown by the radioactive tracers (as per regional experience).

3.6.4.5 Production Logging

Production Logging uses downhole spinner and other tools to identify zonal contributions of water and gas, and changes with time where multiple logs are run.

3.6.4.6 Tiltmeters

Tiltmeter diagnostics were not run in ATP 855 wells, but they were applied by Beach to the Holdfast-1 and Encounter-1 wells in SA in PEL 218 (Figure 1). Tiltmeter data is used in vertical wells to determine the orientation of fracture stimulation growth (horizontally or vertically).

3.7 AFFECTED AREAS

Although the focus of this UWIR is the take of water from the sub-artesian Halifax bore (section 3.7.2), for completeness, information is also presented on the impacts due to fracture stimulation operations in the Cooper Basin.

3.7.1 Affected Areas due to Cooper Basin Operations

There is low potential for the petroleum sector operations to impact on existing water users, based on the GAB Resource Study Update (GABCC, 2010):

> *"There is little immediate scope for conflict between the interests of the rural users of water from the GAB and those of the petroleum sector. As a general rule, petroleum is produced from the GAB at depths greater than 1300 metres—that is, from only the deepest of the aquifers or from those of the upper aquifers which lie below the general economic depth for the drilling of water bores. The combination of these factors means that, with rare exception, there is limited scope for petroleum operations to influence the productivity of nearby water bores through changes in aquifer pressure—they generally do not connect with water-bearing aquifers. In addition, water produced from oil reservoirs can be of poor quality or saline."*

Note that these comments apply to petroleum sector operations in Eromanga Basin aquifers (Jurassic-Cretaceous age), whereas the ATP 855 fracture stimulation operations are undertaken on deeper and low permeability Cooper Basin (Permian age) tight gas plays. The intervening thick regional seal (aquitard) formed by the Triassic Nappamerri Group tends to isolate any effects on the overlying GAB due to extraction of what are quite small volumes of water from the low permeability Permian sediments in the Nappamerri Trough.

For the purpose of estimating affected areas for this UWIR due to fracture stimulation operations, the de Glee steady state leaky aquifer analytical equation was applied to evaluate the potential pressure effect of extraction directly from the GAB formations (rather than from the deeper Permian formations that were actually tested in ATP 855). The de Glee equation was selected because it has been applied in the Far North Water Allocation Plan in South Australia (SAALNRM Board, 2009) as a simple method to estimate drawdown impacts, and it has also been used to estimate impacts relating to Cooper Basin unconventional gas operations in SA (Middlemis, 2014).

Data from the ATP 855 investigations were used in the calculation of affected areas. For example, the longest test was undertaken at Halifax-1 (about 200 days between January and August 2013 - see Table 3), involving the largest volumes of injection (20 ML) and flowback (16 ML), with an average extraction of 40 kL/day. Testing at Halifax-1 indicated average permeability in the micro-Darcy order of magnitude. For the purpose of this conservative calculation, a value of 6×10^{-6} m/day was adopted as the horizontal hydraulic conductivity (Kh), and a value of 6.0×10^{-7} m/day was applied to the vertical hydraulic conductivity (Kv).

Other conservative factors were applied for the conservative calculation, including:

- aquifer thickness of 100 m was assumed (Halifax-1 shows almost 500 m of Patchawarra, but the lithology shows a range of sandstone and siltstone and not all horizons produce water)
- extraction rate of 40 kL/d (equivalent to the average rate during the Halifax test, noting that most of this water was recovered water from the injection, not formation water)
- aquitard package thickness of 100 m (noting that the main GAB aquitard (Wallumbilla Formation) is 400 m thick at Halifax-1; and noting that Permian aquitard thicknesses above the Permian formations actually tested at Halifax-1 include the Nappamerri Group 600 m, Roseneath Shale 240 m and Murteree Shale 80 m).

The result of the steady state de Glee calculation (applied conceptually and conservatively to GAB aquifers) is a steady state drawdown prediction of 0.3 m at a radial distance of 3000 m from the well, as outlined in the spreadsheet screenshot opposite. A steady state drawdown calculation is a valid prediction of maximum long term aquifer responses, consistent with the modelling guidelines (Barnett et al, 2012).

de Glee (1931) leaky aquifer solution	
coded by Hugh Middlemis	Permian K = 8 uD Q = 40 kL/d
s = drawdown (m) = {Q/2.pi.K.D}.Ko(r/L)	0.323
at distance r from a well pumping at Q	
Q = well discharge (kL/d)	40
r = distance from well (m)	3000
K = aquifer permeability (m/d)	6.00E-06
D = aquifer thickness (m)	100
Transmissivity T = K.D (m^2/d)	0.0006
3*D constraint (Leakage factor L must be >3D) (m)	300
L = SQRT(K.D.c) [same as L = SQRT(T.D'/K')]	316
c = aquitard hydraulic resistance (days)	
c = D'/K' {also c = L^2/KD = ([1/(r/L)^2] x [r^2/KD]) }	166,666,667
D' = aquitard saturated thickness (m)	100
K' = aquitard Kv (m/d)	6.00E-07
(note: Modflow Vcont = K'/D' = 1/c; day^-1)	6.00E-09
Ko(r/L) = modified Bessel function	3.04769E-05
of second kind and zero order (Hankel)	
r / L = Bessel argument	9.487

This indicates a maximum potential affected area due to fracture stimulation operations of less than 3 km (i.e. a Long Term Affected Area (LTAA) of less than 3,000 ha). For the sake of simplicity, the Immediately Affected Area (IAA) estimate can also be taken as 3 km in this case due to fracture stimulation operations.

It is noted that there are no GAB springs within the ATP 855 tenement and there are no third party bores within 3 km of any Beach well in ATP 855.

3.7.2 Affected Areas due to Sub-Artesian Halifax Water Bore Extractions

Discussions with the Dept of Environment and Heritage Protection (DEHP) confirmed that the exercise of underground water rights in this case is largely the take of water from the sub-artesian Winton Formation (“Halifax bore”). As a conservative approach, the hydrogeological impact assessment analysis assumes an average long term extraction from the Halifax sub-artesian water bore at a hypothetical rate of 1 L/s (consistent with the average extraction over the 2013-2014 period), although it should be noted that there are no immediate plans for additional production.

For the purpose of estimating affected areas for this UWIR due to extraction from the sub-artesian Halifax bore at an average rate of 1 L/s, the hydrogeological standard Theis analytical equation was applied. As there are no published aquifer parameter values for the Winton Formation, the transmissivity was back-calculated on the basis of operational data indicating Halifax bore pumping at rates of around 2 L/s, and noting the bore construction log (Appendix A) indicates a nominal available drawdown of not more than 30 m. Application of the Theis equation with a 30 m drawdown constraint indicates that the transmissivity must be about 10 m^2/d (or possibly higher) and the confined storativity should be in the range 0.001 to 0.0001, which is typical for a confined to semi-confined aquifer. A lower transmissivity assumption (e.g. even 5 m^2/d) generates excessive drawdowns for those typical storativity values. For the purpose of the affected area calculation, a Winton Formation transmissivity of 10 m^2/d was applied, with a conservative storativity of 0.0001.

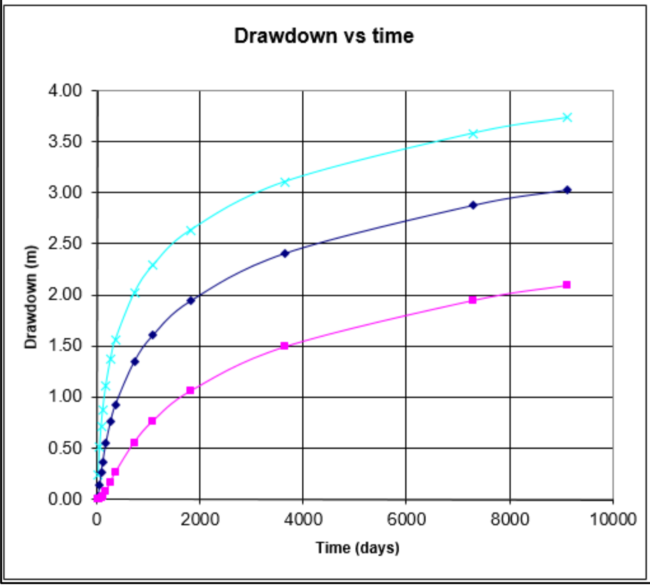
Figure 22 presents the parameter values and results of the Theis analytical model in terms of time-drawdown for various distances up to 10 km and distance-drawdown for various times up to 25 years, which allows for evaluation of uncertainty. For a bore trigger value of 5 m drawdown, the results indicate a conservative affected area of 3 km from the Halifax bore for periods up to 25 years (again, as there are no immediate plans for additional production, this is a prediction of potential affect).

Figure 22 - sub-artesian Halifax bore affected area calculations using Theis

Time-drawdown calculations using Theis equation

Aquifer parameters		
T	10	m2/d
S	0.0001	
B		
Pumping rate		
Q	1	l/s

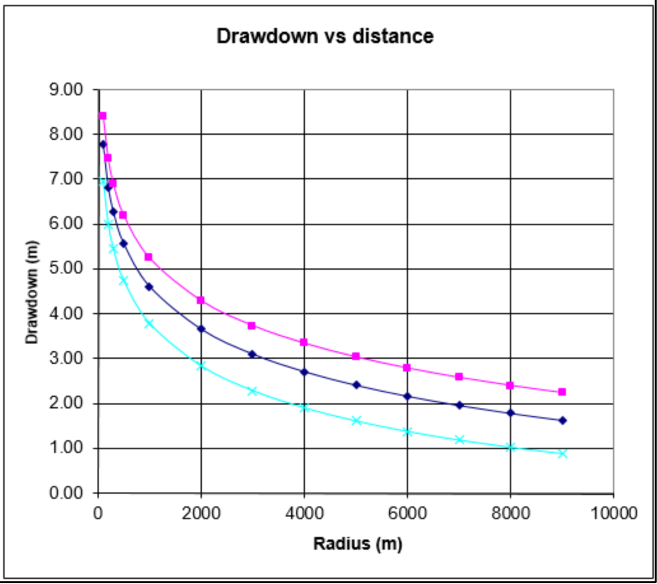
Radius (m)	3000	5000	10000
Time (days)	Drawdown (m)	Drawdown (m)	Drawdown (m)
30	0.234	0.030	0.000
60	0.513	0.141	0.002
90	0.718	0.260	0.012
120	0.877	0.368	0.030
180	1.116	0.550	0.081
270	1.368	0.760	0.171
365	1.561	0.929	0.264
730	2.017	1.351	0.557
1095	2.288	1.611	0.767
1825	2.634	1.946	1.061
3650	3.106	2.411	1.493
7300	3.581	2.882	1.946
9125	3.734	3.034	2.095



Distance-drawdown calculations using Theis equation

Aquifer parameters		
T	10	m2/d
S	0.0001	
B		
Pumping rate		
Q	1	l/s

Time (days)	1095	3650	9125
Radius (m)	Drawdown (m)	Drawdown (m)	Drawdown (m)
100	6.951	7.779	8.409
200	5.998	6.826	7.456
300	5.441	6.268	6.898
500	4.739	5.566	6.196
1000	3.787	4.613	5.243
2000	2.838	3.661	4.290
3000	2.288	3.106	3.734
4000	1.904	2.714	3.339
5000	1.611	2.411	3.034
6000	1.376	2.166	2.786
7000	1.184	1.960	2.576
8000	1.022	1.783	2.395
9000	0.885	1.629	2.237



4. PART C – MAPPING AFFECTED AREAS

As this is the first UWIR produced for ATP 855, there are no maps to review as required by the Water Act. As there are no plans to undertake production or testing in the near future, it is presumed that a future UWIR will not be required until such time as Beach plan to initiate operations on ATP 855.

The UWIR bore trigger threshold is a 5 metre drawdown, and the very local scale affected areas have been calculated as less than 3 km from any well within ATP 855 (Section 3.7):

- the de Glee model of steady state drawdown was used to calculate a maximum drawdown of 0.3 m at 3 km radius from any site due to a long term extraction rate of 40 kL per day, conceptually from a GAB aquifer (under a range of very conservative assumptions), due to fracture stimulation operations (section 3.7.1)
- the Theis analytical model was used to calculate a conservative affected area (short term and long term) of less than 3 km due to extraction from the sub-artesian Halifax bore at a rate of 1 L/s (section 3.7.2 and Figure 22).

There are no GAB springs within the ATP 855 tenement and there are no third party bores within 3 km of any Beach well in ATP 855 (Figure 9 and Figure 10). The map at Figure 1 shows green squares around each site in ATP 855 (the 2C resource areas) that correspond approximately to the 3 km potentially affected areas.

The latest Minister's statement (State of Queensland, 2015) provides some insights on artesian and sub-artesian aquifer systems of the GAB:

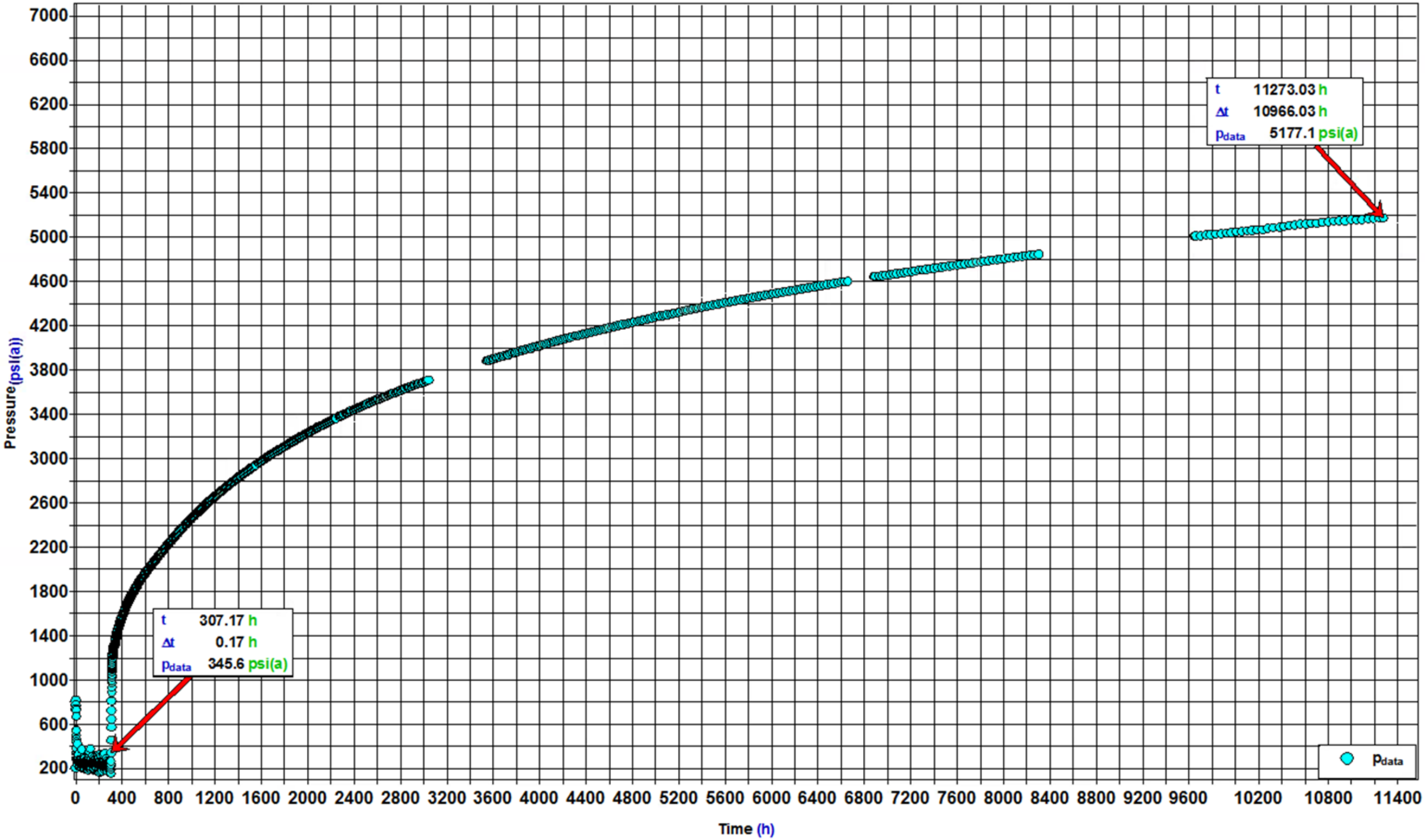
- "The hydrographs from monitored **artesian bores** in most plan aquifers indicate that groundwater pressure appears to be stable or rising" (except for the Surat, Surat East, or Surat North management areas); the "implications of these trends are yet to be fully understood and more detailed analysis of the pressure data will be undertaken during 2015 via a hydrogeological study that will inform the preparation of the new plan."
- "Stable or rising groundwater pressure trends suggest that in the majority of plan aquifers, the reliability of water supply is being maintained and protected. The capping of more than 676 uncontrolled bores to date through programs such as the Great Artesian Basin Sustainability Initiative (GABSI) is facilitating the recovery of groundwater pressure across plan aquifers."
- "There are no obvious trends in the water levels in **subartesian aquifers**; however, there may be some climatic influences. The hydrogeological study will also make a detailed examination of the water level data."

While there is a reasonable level of broad hydrogeological knowledge in the region, notably documented in the 2012 CSIRO studies of the GAB (cited herein), there is very little specific hydrogeological data or mapping available on Cooper Basin aquifer and aquitard systems in the project area. Some information that is available has been presented in Section 3 (Part B – Aquifer Information), and there is a Bioregional Assessment study in progress (funded by the Federal Government) that will improve hydrogeological understanding on the Cooper Basin through 2016, when improved mapping may be possible: bioregionalassessments.gov.au/bioregions/leb.shtml.

In regard to the affected areas calculation for the Cooper Basin fracture stimulation operations, it should also be noted that the drawdown registered in the overlying GAB aquifer system would be effectively not measurable due to the influence of the intervening main GAB aquitard of the Wallumbilla Formation. In fact, drawdown would likely not be measureable in the GAB formations as a result of extractions from the underlying Permian units accessed in ATP 855, due to the 400 m plus thickness of intervening aquitard (regional seal) of the Nappamerri Formation.

Furthermore, pressure logger data provided by Beach provides some insights to the reservoir pressure changes at Halifax-1 (tested over almost 200 days to August 2013, and involving the greatest volumes of 20 ML injected and 16 ML flowback). The pressure logger installed on the tubing provided data on pressures during the stimulation treatment and flowback (i.e. until about 4700 hours on the plot, indicating the 195 day test duration from January to August 2013), as well as the subsequent shut-in wellhead pressure converted to an equivalent bottomhole pressure (Figure 23). The data logger remained installed on the tubing and at 20 January 2015 (512 days later) the shut-in pressure was 3678 psig (or equivalent calculated bottom hole pressure of almost 5200 psia). Similar results were obtained from the other tests, and all tests indicated 80%-90% pressure recovery to pre-test levels within a post-test recovery period of about three times the duration of the pressure buildup test (i.e. no long term reservoir effects).

Figure 23 - Halifax-1 logger data from pressure buildup test



5. PART D – WATER MONITORING STRATEGY

The latest Minister's statement (State of Queensland, 2015) indicates that:

- "groundwater pressure appears to be stable or rising" in the artesian and sub-artesian aquifer systems of the GAB (except for the Surat, Surat East, or Surat North management areas),
- "in the majority of plan aquifers, the reliability of water supply is being maintained and protected", and,
- "The capping of more than 676 uncontrolled bores to date through programs such as the Great Artesian Basin Sustainability Initiative (GABSI) is facilitating the recovery of groundwater pressure across plan aquifers."

The investigations undertaken to date in ATP 855 are detailed herein and can be summarised as:

- monitoring at the sub-artesian Halifax water bore did not show any pressure or flow effects during test production at Halifax-1 (the longest test and involving the greatest volumes). Pressure logger data (Figure 23) demonstrates that reservoir pressures have recovered within a post-test period of about three times the duration of the pressure buildup test, which is as expected from operational oilfield experience.
- conservative steady-state De Glee analytical modelling of Cooper Basin operations and Theis analytical modelling of sub-artesian extractions (see Section 3.7) identifies a maximum potential affected area of less than 3 km. There are no third party bores within 3 km of any Beach site in ATP 855, and the nearest GAB springs are more than 200 km to the south-east.
- the Permian formations accessed for testing at ATP 855 are not listed in the GAB Management Areas/Units and Aquifers for the Central Management Zone under Schedule 4 of the Water Resource (GAB) Plan 2006.
- there are no plans to undertake production or testing in the near future.

Under these conditions, with test production to date involving low volumes and no measurable impacts, the uncertain timing of further production testing, no third party bores within impact areas, and the nearest GAB springs more than 200 km from ATP 855, a monitoring plan is considered not required.

Nonetheless, following detailed consultation with the DEHP, Beach commits to undertake an annual review of the accuracy of assessments and mapping provided in this UWIR and to provide a summary of the outcome of each review to the Chief Executive of the relevant department (DEHP at the time of writing). The first annual review is scheduled to occur one year after approval of this UWIR. Otherwise, as required by the Water Act 2000 (Qld), a new UWIR will be compiled every 3 years and submitted to DEHP.

In the meantime, the Bioregional Assessment study in progress through 2016 (funded by the Federal Government) will improve hydrogeological understanding on the Cooper Basin, and will help prioritise efforts for appropriate water monitoring strategies.

6. PART E – SPRING IMPACT MANAGEMENT STRATEGY

The GAB springs are the key identified groundwater dependent ecosystems (GDEs), and they are dependent on piezometric pressures in the GAB aquifers. A key issue for GAB aquifer management is the limits imposed on drawdowns at springs in Queensland. Specifically, a 5 km buffer zone applies around springs, where cumulative drawdown must not exceed 400 mm vertically.

There are no mapped springs within ATP 855. The nearest spring complex to ATP 855 is the Yowah spring complex, located more than 200 km to the south-east (Figure 10). The closest ATP 855 well to the Yowah complex is Geoffrey-1, located at 277 km distance. There is another un-named spring to the north-west of ATP 855, and the closest well is again Geoffrey-1 at 220 km.

As no springs exist within ATP 855 or within any potentially affected area, a spring management strategy is not required for this UWIR:

- Connectivity between the spring and the aquifer - not applicable.
- Management of Impacts - not applicable.
- Timetable for Strategy - not applicable.
- Reporting Program - not applicable.

7. PART F - CUMULATIVE MANAGEMENT AREA

As ATP 855 is not part of a Cumulative Management Area, responsibility for the preparation of a UWIR rests with the petroleum tenure holder (Beach Energy).

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Appendix A - Halifax water bore driller's log and government database records

Bore Registration

RN	NAME	FACILITY TYPE	FACILITY STATUS	PARISH	DRILLED DATE	CONSTRUCTED	BASIN	DESCRIPTION	COUNTY	FORMATION DESCRIPTION (at TD)	CONDITION	EASTING	NORTHING	GIS LAT	GIS LNG	EQUIPMENT	LOCATION	Formation Top	Formation Bottom	Total Depth TD	Plugback Depth	RT datum	Perforation Formations
6052	MUALAWARRA BORE	SF	EX	310	01/01/1919	CABLE TOOL	31	NAPPAMERRY HOLDING	COOPER			513025	6925099	-27.79849061	141.1323485	Windmill	10 km Buffer						
6054	KILUMBRAILI	SF	AD	3792	01/01/1926	CABLE TOOL	31	PEPITA HLD	PENDER			527606	6972152	-27.37348753	141.2792865	No equipment	10 km Buffer						
6056	KOOKOONA BORE	SF	EX	3792	01/01/1930	CABLE TOOL	31	CHASTLETON HOLDING	PENDER			543712	6967151	-27.4182082	141.4423412	Windmill	ATP855						
12661		SF	AD	3085	19/12/1953	CABLE TOOL	31	NAPPA MERRIE HOLDING	COOPER	WINTON FORMATION	Consolidated	533356	6925429	-27.7951551	141.3387356	No equipment	10 km Buffer	83	301				
16768	DIO INNAMINCKA 2	AF (HW)	EX	3792	06/09/1965	ROTARY RIG	31	CHASTLETON HOLDING	PENDER	HUTTON SANDSTONE	Consolidated	505527	6963578	-27.4510425	141.0574634	Headworks (Artesian)	10 km Buffer	1832	1889				
22666	NARYILCO NO 1 W/WELL	SF	EX	3792	01/01/1970		31		PENDER	WINTON FORMATION	Consolidated	526477	6971231	-27.38182099	141.2678977	No equipment	10 km Buffer	201	250				
22667	NARYILCO NO2 W/WELL	SF	AD	3792			31		PENDER	WINTON FORMATION	Consolidated	526477	6971231	-27.38182099	141.2678977	No equipment	10 km Buffer	59	105				
22740	FPN TALLALIA 1	AF (NE)	EX	3792	06/10/1970	ROTARY RIG	31		PENDER			524348	6972051	-27.37459897	141.2462311	No equipment	10 km Buffer						
23258	DIO CHALLUM 1	AF	EX	3792	26/12/1983		31					556724	6969918	-27.39292912	141.5737287		10 km Buffer						
23539	DIO CHALLUM 3	AB	EX	3792	20/08/1985			A TO P 259P				553345	6970486	-27.38792942	141.5395623		10 km Buffer						
23713	DIO CHALLUM 4	AB	EX	3792	03/11/1987			A TO P 259P				563464	6967326	-27.4159841	141.6420616		10 km Buffer						
23749	DIO CHALLUM 5	AB	EX	3792	03/03/1988			A TO P 259P				565114	6967251	-27.41653951	141.6587281		10 km Buffer						
50087	SANDY CREEK BORE	SF	EX	3684	01/01/1976		31	NAPPAMERRY HOLDING	COOPER			504489	6929259	-27.76099153	141.0456823	Windmill	10 km Buffer						
50355	HONEYMOON WELL	SF	AD	3497		PICK AND SHOVEL	31	CHASTLETON HOLDING	COOPER			506828	6952243	-27.55349061	141.0692905	Windmill	10 km Buffer						
116059		SF	AD	3085	06/02/2013	ROTARY MUD; ROTARY AIR	31	DRILL LOG #1042220	COOPER			520045	6934290	-27.71555556	141.2033333		ATP855						
116076		SF	AD	3085	04/02/2013	ROTARY MUD; ROTARY AIR	31	DRILL LOG #1042219	COOPER			521252	6935980	-27.70027778	141.2155556		ATP855						
116263	DIG TREE 1	SF	EX	3792	13/07/2008	MUD ROTARY	31		PENDER	WINTON FORMATION	XX	515029	6953343	-27.543817	141.1522824	No equipment	ATP855	38	40				
116272		SF	EX	3792	22/10/2009	ROTARY MUD	31		PENDER	WINTON FORMATION	Consolidated	543440	6968731	-27.40408332	141.4394171		10 km Buffer	108	136				
116273		SF	EX	3792	18/10/2009	ROTARY MUD	31		PENDER	WINTON FORMATION	Consolidated	534652	6962472	-27.4608426	141.3507049		ATP855	23	44				
116274		SF	EX	3792	19/10/2009	ROTARY MUD	31		PENDER	WINTON FORMATION	Consolidated	539789	6964712	-27.44047946	141.4026164		ATP855	58	77.5				
116306		SF	EX	3085	11/11/2013	ROTARY MUD	31	DRILL LOG #1012167	COOPER	0	Unconsolidated	504954	6929382	-27.76	141.0502778		10 km Buffer	43	48				
116331		SF	EX	3085	15/10/2013	ROTARY MUD	31	DRILL LOG #1012164	COOPER	0	Consolidated	519953	6928321	-27.76944444	141.2025		10 km Buffer	262	278				
116395	TEST HOLE	SF	AD	3085	25/03/2013	ROTARY MUD	31					502925	6925530	-27.79477965	141.0296893		10 km Buffer						
160485	BEACH ENERGY	SF	EX	3085	06/05/2013	ROTARY MUD	31	DRILL LOG 1006653	COOPER			534718	6932903	-27.72777778	141.3522222		ATP855						
	Etty-1	GS	EX		26/03/2014					PATCHAWARRA FORMATION		514918	6936674				ATP855			3807	3354	79.2	Toolachee and Daralingie Formations
	Geoffrey-1	GS	EX		09/12/2013					PATCHAWARRA FORMATION		562732	6956775				ATP855			4266	4119	77.6	Epsilon and Patchawarra Formations
	Halifax-1	GS	EX		22/10/2012					PATCHAWARRA FORMATION		506296	6936673				ATP855			4267	4205	68.6	Toolachee, Daralingie, REM and Patchawarra Formations
	Hervey-1	GS	EX		11/07/2013					PATCHAWARRA FORMATION		534988	6932959				ATP855			4266	3692	86.6	Toolachee, Daralingie and Patchawarra Formations
	Redland-1	GS	EX		23/01/2014					DARALINGIE FORMATION		541165	6961890				ATP855			3804	3763	81.2	Toolachee and Daralingie Formations
	Keppel-1	GS	AD		08/08/2013					EPSILON FORMATION		525405	6953221				ATP855			3898	plugged	70.2	Plugged and Suspended

Water Level Measurements

ORIG NAME N	RN	FACILITY TYPE	PIPE	RDATE	MEAS POINT	MEASUREMENT
DIG TREE 1	116263	SF	A	39642	N	-24
	12661	SF	X	19712	N	-48.1

Field Water Analysis

ORIG NAME NO	RN	FACILITY TYPE	PIPE	RDATE	SAMP METHOD	SOURCE	DEPTH	CONDUCT	DO2	EH	NO3	PH	TEMP	ALKALINITY
DIO INNAMIN	16768	AF	A	39002	PU	GB		6300				7.3	40.6	
DIO INNAMIN	16768	AF	A	33844	PU	GB	1832	6500					46	
DIO INNAMIN	16768	AF	A	39715	PU	GB		6330				7	39.6	
DIO INNAMIN	16768	AF	A	41074	PU	GB		6310				7	41.4	

Water Analysis

ORIG NAME NO	RN	FACILITY TYPE	PIPE	RDATE	REC	ANALYST	ANALYSIS NO	SAMP METHOD	SOURCE	PRESMETH1	COLLSAMP	PROJECT1	DEPTH	CONDUCT	PH
DIO INNAMIN	16768	AF	A	26578	1	GCL	54660	PU	GB					6400	7.9
DIO INNAMIN	16768	AF	A	29483	1	GCL	87478	PU	GB					6400	8.2
DIO INNAMIN	16768	AF	A	33844	1	GCL	147912	PU	GB					6300	8.2
DIO INNAMIN	16768	AF	A	39002	1	GCL	218429	PU	GB	NL	DG	GWAN	1832	6270	8.3

ORIG NAME NO	RN	COLOUR	COLOUR IND	TURB	TURB IND	SIO2	SIO2 IND	HARD	ALK	ALK IND	FIG MERIT	NA ADS RATIO	RES ALK	TOTAL IONS	TOTAL SOLIDS
DIO INNAMIN	16768							80	2361		0	83.6	45.58	5648.2	0
DIO INNAMIN	16768					88		58	2198		0	94.2	42.76	5337	4062.76
DIO INNAMIN	16768					99		34	2166		0	117.1	42.63	5151.65	3945.49
DIO INNAMIN	16768	2		3		92		35	2330		0	120.3	46	5390	4080

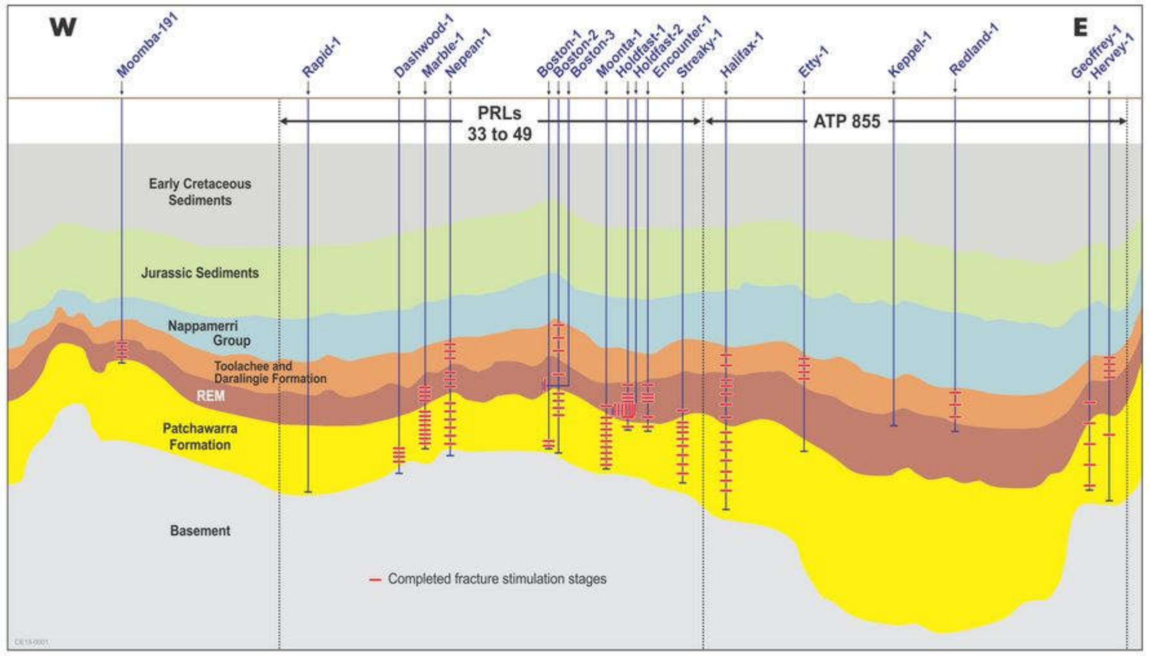
ORIG NAME NO	RN	NA	NA IND	K	K IND	CA	CA IND	MG	MG IND	FE	MN	FE IND	MN IND
DIO INNAMIN	16768	1717				4		17					
DIO INNAMIN	16768	1650		12		15		5					
DIO INNAMIN	16768	1568		14.3		11.3		1.4		0.03	0.02		
DIO INNAMIN	16768	1640		15		11		1.7		0.01	0.03	<	

ORIG NAME NO	RN	HCO3	HCO3 IND	CO3	CO3 IND	CL	CL IND	F	F IND	NO3	NO3 IND	SO4	SO4 IND	ZN	ZN IND
DIO INNAMIN	16768	2879				1030		1.2				0			
DIO INNAMIN	16768	2680		0		964		1		0		10			
DIO INNAMIN	16768	2567.5		36.9		951		1.28		0		0			
DIO INNAMIN	16768	2770		33		915		1.2		5	<	20	<	0.05	

ORIG NAME NO	RN	AL	AL IND	B	B IND	CU	CU IND	PO4	PO4 IND	BR	BR IND	I	I IND
DIO INNAMIN	16768												
DIO INNAMIN	16768												
DIO INNAMIN	16768												
DIO INNAMIN	16768	0.05	<	6		0.03	<						

Fracture stimulation intervals

Well	Date	Patchawarra	Murteree	Epsilon	Roseneath	Daralingie	Toolachee	Water Source
Halifax-1	Dec-12	7	1	2	2	1	1	Halifax Bore
Hervey-1	Sept-14	1				1	3	Halifax bore RO treated
Etty-1	Oct-14					1	3	Halifax bore RO treated
Redland-1	Oct-14					1	3	Halifax bore RO treated
Geoffrey-1	Nov-14	4		1				Halifax bore RO treated



These wells are all in the 10km buffer region

16768 DIO INNAMINCKA 2

FORMATION	TOP	BOTTOM
WINTON FORMATION	4.9	734.9
MACKUNDA FORMATION		
ALLARU MUDSTONE	730	1116.2
WALLUMBILLA FORMATION	1116.2	1368.6
CADNA-OWIE FORMATION	1368.6	1463.3
HOORAY SANDSTONE	1463.3	1612.4
WESTBOURNE FORMATION	1612.4	1734
ADORI SANDSTONE	1734	1773
BIRKHEAD FORMATION	1773	1838.2
HUTTON SANDSTONE	1838.2	2015.3
BASAL JURASSIC UNIT	2015.3	2040.3
NAPPAMERRI GROUP	2040.3	2551.8
PATCHAWARRA FORMATION	2551.8	3298.5
TIRRAWARRA SANDSTONE	3298.5	3349.1
MERRIMELIA FORMATION	3349.1	3444.8
SEDIMENTS	3444.8	3585.4

23258 DIO CHALLUM 1

FORMATION	TOP	BOTTOM
SEDIMENTS	6.1	
GLENDOWER FORMATION		
WINTON FORMATION		
MACKUNDA FORMATION	774.2	895.5
ALLARU MUDSTONE	895.5	1107.6
TOOLEBUC FORMATION	1107.6	1129.3
WALLUMBILLA FORMATION	1129.3	1448.1
CADNA-OWIE FORMATION	1448.1	1552
HOORAY SANDSTONE	1552	1689.8
WESTBOURNE FORMATION	1689.8	1811.7
ADORI SANDSTONE	1811.7	1829.4
BIRKHEAD FORMATION	1829.4	1889.4
HUTTON SANDSTONE	1889.4	2039.1
NAPPAMERRI GROUP	2039.1	2296.1
GIDGEALPA GROUP	2296.1	2378.1
MERRIMELIA FORMATION	2378.1	2430.2
BASEMENT	2430.2	2465.8

23713 DIO CHALLUM 4

FORMATION	TOP	BOTTOM
SEDIMENTS	6.2	
GLENDOWER FORMATION		
WINTON FORMATION		
MACKUNDA FORMATION	806.8	902.2
ALLARU MUDSTONE	902.2	1108.9
TOOLEBUC FORMATION	1108.9	1132
WALLUMBILLA FORMATION	1132	1515.2
CADNA-OWIE FORMATION	1515.2	1612.5
HOORAY SANDSTONE	1612.5	1746.2
WESTBOURNE FORMATION	1746.2	1887.9
ADORI SANDSTONE	1887.9	1900.1
BIRKHEAD FORMATION	1900.1	1970.8
HUTTON SANDSTONE	1970.8	2072.6
NAPPAMERRI GROUP	2072.6	2311.3
GIDGEALPA GROUP	2311.3	
MERRIMELIA FORMATION		
METASEDIMENTS	2509.7	2549.7

22740 FPN TALLALIA 1

FORMATION	TOP	BOTTOM
SEDIMENTS	5.6	
WINTON FORMATION		
MACKUNDA FORMATION	672.1	762
ALLARU MUDSTONE	762	961.6
WALLUMBILLA FORMATION	961.6	1379.5
CADNA-OWIE FORMATION	1379.5	1472.2
HOORAY SANDSTONE	1472.2	1629.5
WESTBOURNE FORMATION	1629.5	1756.9
ADORI SANDSTONE	1756.9	1773.9
BIRKHEAD FORMATION	1773.9	1834.9
HUTTON SANDSTONE	1834.9	2002.5
NAPPAMERRI GROUP	2002.5	2299.7
GIDGEALPA GROUP	2299.7	2923
PATCHAWARRA FORMATION	2299.7	2849.9
TIRRAWARRA SANDSTONE	2849.9	2923
UNDIFFERENTIATED	2923	3005.3
MERRIMELIA FORMATION	3005.3	3191.6

23539 DIO CHALLUM 3

FORMATION	TOP	BOTTOM
SEDIMENTS	5.8	
WINTON FORMATION		
MACKUNDA FORMATION		
ALLARU MUDSTONE	839.9	1045.8
TOOLEBUC FORMATION	1089.8	1113.4
WALLUMBILLA FORMATION	1113.4	1499.3
CADNA-OWIE FORMATION	1499.3	1598.7
HOORAY SANDSTONE	1598.7	1733.7
MURTA FORMATION	1598.7	1667
NAMUR SANDSTONE	1667	1733.7
INJUNE CREEK GROUP	1333.7	1531.8
WESTBOURNE FORMATION	1733.7	1855
ADORI SANDSTONE	1855	1872.1
BIRKHEAD FORMATION	1872.1	1931.8
HUTTON SANDSTONE	1931.8	2050.7
NAPPAMERRI GROUP	2050.7	2295.4
GIDGEALPA GROUP	2295.4	2474.7
METASEDIMENTS	2519.3	2549.3

23749 DIO CHALLUM 5

FORMATION	TOP	BOTTOM
SEDIMENTS	5.7	
GLENDOWER FORMATION		
WINTON FORMATION		
MACKUNDA FORMATION	775.1	889.4
ALLARU MUDSTONE	889.4	1130.8
TOOLEBUC FORMATION	1130.8	1155.8
WALLUMBILLA FORMATION	1155.8	1508.8
CADNA-OWIE FORMATION	1508.8	1610.5
HOORAY SANDSTONE	1610.5	1756
WESTBOURNE FORMATION	1756	1899.5
ADORI SANDSTONE	1899.5	1909.9
BIRKHEAD FORMATION	1909.9	1979.4
HUTTON SANDSTONE	1979.4	2096.1
NAPPAMERRI GROUP	2096.1	2342.4
GIDGEALPA GROUP	2342.4	
MERRIMELIA FORMATION		
METASEDIMENTS	2587.4	2622.5

DOWNHOLE DIAGRAM

WELL: **Halifax**

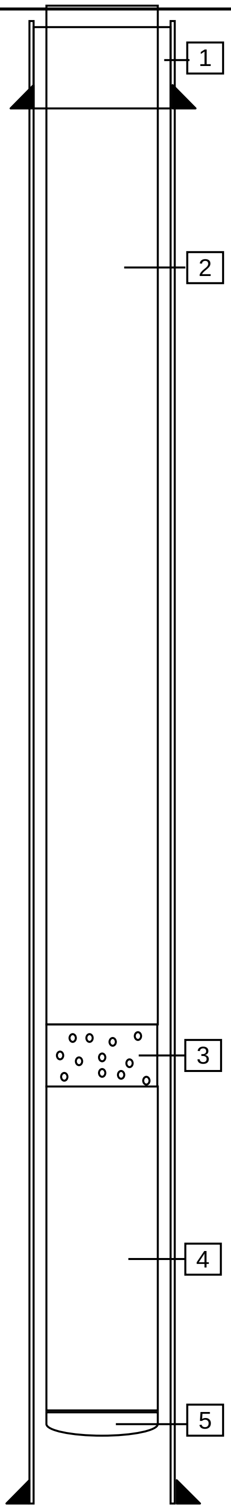
Watson Drilling

DATE: 5th July 2012

Deniliquin.

Co-ordinates: E 492673 N 6921682

NSW



TD: 66m

ITEM No.	DESCRIPTION	LENGTH (m)	DEPTH KB (m)	MIN. ID (in)
1	500mm stick up above ground level	0.5m	0.00	
2	52 m of Class 12 177mm PVC (9 Lengths)	52m	52.00	
3	12m of Stanless Steel Screen (.75mmm/30 thou)	12m	64.00	
4	1m of Class 12 177mm PVC Sump	1m	65m	
5	1 150mm Class 18 End Cap	.1m	65.1m	

PERFORATION INTERVALS: .75mm or 30 Thou

FORMATION	INTERVAL (m RT)	GUN:				CHARGES:	
		SIZE	TYPE	PHASE	SPF	TYPE	WT(g))

REMARKS:

Drilled 7 7/8" test hole to 120m, then cut out to 12 1/4 " to 66m.

Installed 12m of 30 thou Stanless Steel Screens from 52m to 64m, with a 1m sump.

DEPTH OF DEVELOPMENT: 47m

GALS PER HOUR AND DEPTH: 9000. Static water is 20m

NOT TO SCALE	WELLSITE SUPERVISOR	Gary Mogg	
PROPOSED:	DATE OF INSTALLATION		
RE-COMPLETION:	DRAFTED BY:	DATE:	
COMPLETION:	REVISED BY:	DATE:	
OTHER:			