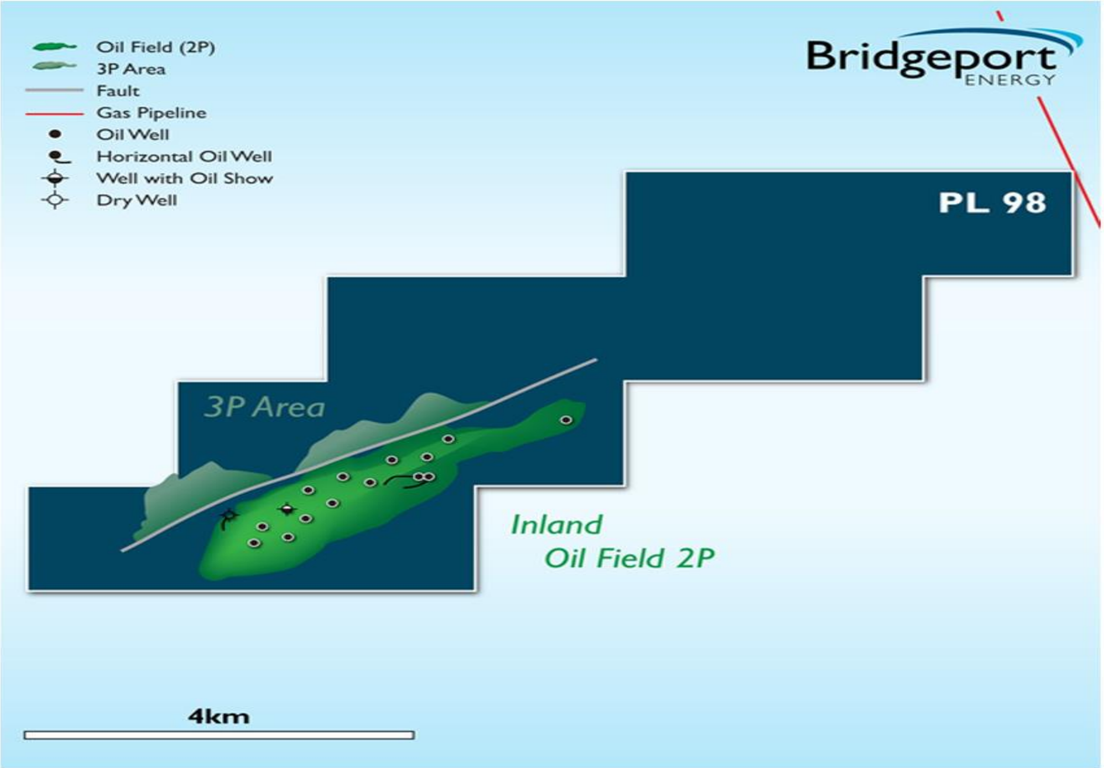

BRIDGEPORT ENERGY
UWIR 2015-2018
PL 98

Bridgeport (Eromanga) Pty Ltd
ACN 148 013 469
Registered Operator Number: 66 33 84

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Appendix A – UWIR 2012 Inland

ACRONYM	DEFINITION
ANZECC	Australia New Zealand Environment and Conservation Council
AS/NZS	Australia New Zealand Standard
BEL	Bridgeport Energy Limited
DEHP	Department of Environment & Heritage Protection
DNRM	Department of Natural Resources and Mines
GDE	Groundwater Dependant Ecosystems
ML	Megalitres
PL	Petroleum Lease
OWK	Oilwells Inc. Of Kentucky
STB	Stock Tank Barrel
UWIR	Underground Water Impact Report

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Document Revision and Issue Status

Revision	Date Reviewed	Recipients/Reviewers
Final Draft	30 November 2015	S Hingerty / C Way
Revision incorporating DEHP comments	21 March 2016	Iveta Mylchreest

This UWIR for PL 98 is issued by authority of Bridgeport Energy (Eromanga) Limited, under the authority of the Bridgeport CEO and will be reviewed again in December 2018

Christopher Way

November 2015

CHRIS WAY

1. Background

The first UWIR for PL 98 was approved effective 21st of November 2012 (Appendix A). This UWIR is responding to the regulatory requirement under section 370(2)(c) of the Water Act 2000 which provides that: "*An underground water impact report must… be given within 10 business days after each third anniversary of the day the first underground water impact report for the…petroleum tenure took effect*". This also requires the UWIR to be reviewed after its expired 3 year period December 2015.

Bridgeport Energy currently produces oil from the Hutton and Birkhead formation in the PL 98 Inland Oil field. Since UWIR reporting commenced in November 2012 to December 2015 approximately 870.45 ML of associated water has been produced. The reporting of the total amount of water produced in this report complies with the requirement of S376(a)(i) of the *Water Act 2000.*

1.1 Location

The site is located at the Inland Oilfields PL98 near Windorah and Quilpie, Queensland and is currently owned and operated by Bridgeport (Eromanga) Pty Ltd. Petroleum Lease (PL) 98 is located in the north western Eromanga region, approximately 5-6 kilometres (km) east of the Beal Range in Queensland which is situated 1,150 km west of Brisbane. The oil field is situated 120 km west of Windorah, and 290 km from the village of Quilpie.

1.2 Geological Setting

The Cooper Basin covers a total area of 130,000 km^2 and can generally be described as arid with a uniform climate. It contains a wide diversity of land and ecosystem values that are defined by geological, geomorphological and hydrological influences. The Eromanga and Cooper basins are located in central and eastern Australia. The saucer-shaped Eromanga Basin extends over one million square kilometres in Queensland, New South Wales, South Australia, and the south-east of the Northern Territory.

The Eromanga Basin is overlain by the Lake Eyre Basin, a succession of Tertiary and Quaternary age sediments occurring extensively throughout central Australia. In the north east of South Australia, the Lake Eyre, Eromanga Basin sediments were deposited during the Jurassic-Cretaceous period, and reach a maximum thickness of between 1200 m and 2700 m over the Cooper Basin. These sediments were deposited under fluvial, lacustrine 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 aerially-extensive sandstone formations that serve as oil reservoirs and regional aquifers. The Eromanga Basin is the largest of the group of basins that constitute the Great Artesian Basin (GAB). The Eromanga Basin lies within South Australia, the other components being in Queensland and in part in New South Wales. Beneath, and entirely covered by the Eromanga Basin, is the Jurassic – Triassic Cooper Basin, limited in its distribution by bounding faults and pinch-out edges.

The Cooper Basin extends over a much smaller area than the Eromanga and covers a smaller area of about 153,000 km2 in northeast South Australia and southwest Queensland. The tectonic history of the Cooper and Eromanga basins is complex and has been characterised by several periods of rift-related subsidence and compressional uplift and erosion. This history has resulted in the Cooper Basin being subdivided into a number of large scale sub-troughs separated by fault bounded ridges.

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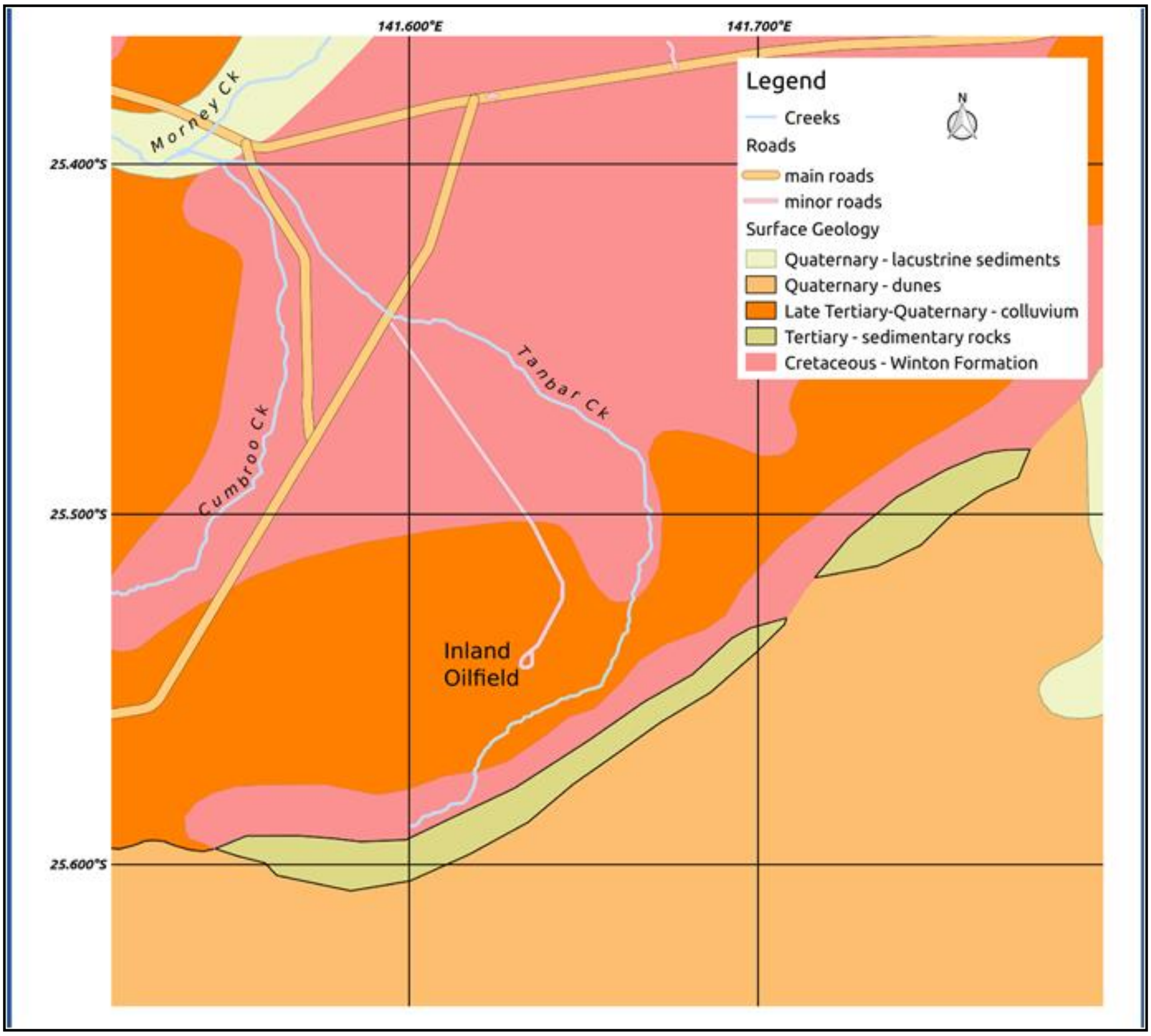


Figure 1 - Regional Geology

Beneath, and entirely covered by the Eromanga Basin, is the Jurassic – Triassic Cooper Basin, limited in its distribution by bounding faults and pinch-out edges. The Cooper Basin extends over a much smaller area than the Eromanga and covers a smaller area of about 153,000 km2 in northeast South Australia and southwest Queensland.

The tectonic history of the Cooper and Eromanga basins is complex and has been characterised by several periods of rift-related subsidence and compressional uplift and erosion. This history has resulted in the Cooper Basin being subdivided into a number of large scale sub-troughs separated by fault bounded ridges. Figure 1 below depicts the stratigraphic column of the Eromanga sequence.

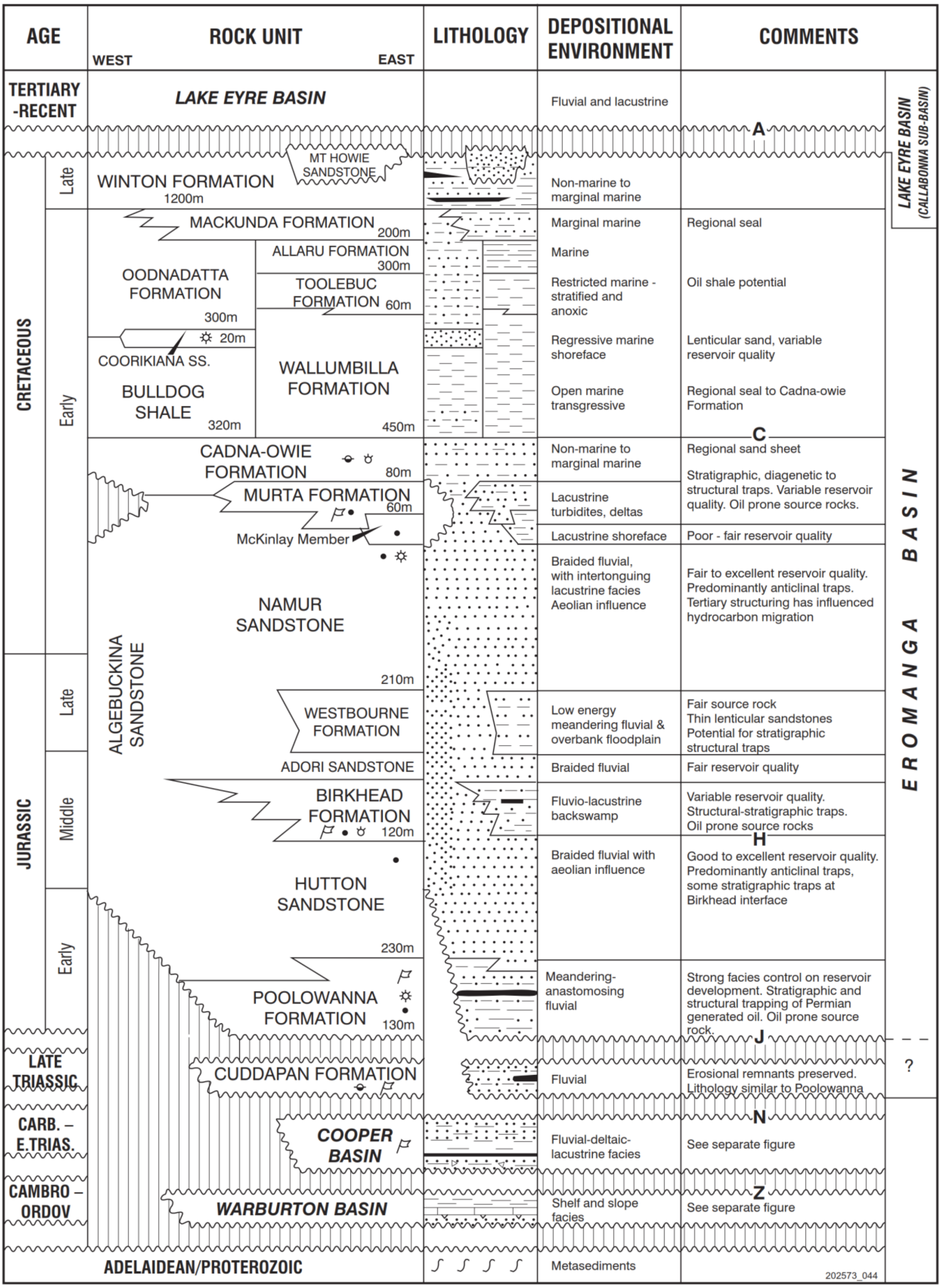


Figure 2: Stratigraphic column of the Eromanga Sequence

1.2.1 Description of the Stratigraphic Sequences

The following describes the stratigraphic sequences depicted in figure 2 above:

a) **Cadna-Owie Formation (1161.1 – 1221.9 mKB) -** Paralic to shallow marine early Cretaceous sediments, the uppermost unit, the Wyandra Sandstone, is an abrupt boundary from the Wallumbilla sediments above. Sandstone: White, very fine – fine, minor medium, trace coarse sub angular quartz, quartzose, common feldspar, moderately hard, weakly – moderately calcareous in part, common – abundant clay matrix. Siltstone: Light – mid brown, arenaceous, firm, minor lithics, trace carbonaceous. Gas: 3-7units. 88/6/3/3/-

b) **Murta Formation (1221.9 – 1225.2 mKB) -** Late Jurassic – earliest Cretaceous braided fluvial system. Interbedded sandstone and siltstone. Sandstone is light grey – off white, fine – minor medium, trace coarse, moderately well consolidated, quartzose, common moderately – strong calcareous cement, trace lithic, poor visible porosity. Siltstone is light – medium grey, moderately hard, weakly laminar, arenaceous, common micromicaceous, minor dark grey argillaceous siltstone. Gas: 12-18units. 70/12/7/11/-

c) **McKinlay Sandstone Member (1225.2 – 1254.6 mKB) -** Sandstone is light grey – off white, very fine – medium, minor coarse, generally coarsening up, quartzose, swelling sticky clay in lower part, nil – weakly calcareous, poor – good porosity. Siltstone: Light – medium grey, minor dark grey, minor carbonaceous laminar, common arenaceous. Gas: 2-18units. 70/12/7/10/-

d) **Namur Sandstone Member (1254.6 – 1359.1 mKB) -** The Namur sandstone is a braided fluvial system of latest Jurassic to earliest Cretaceous age. Sandstone with minor siltstone. Sandstone is fine – very coarse, loose, quartzose, angular, overgrowths in part, layers of swelling sticky clay increasing to base, poor – good porosity. Siltstone: medium grey, common micromicaceous, minor arenaceous, minor feldspar. Gas: 2-10units. 73/10/7/10/-.

e) **Westbourne Formation (1359.1– 1440.3 mKB) -** Late Jurassic sediments, near shore to fluvial / lacustrine in lower part. Siltstone is very fine sandstone and minor sandstone. Sandstone is light grey – light brown, very fine, common – abundant white clay matrix, common swelling clay, weakly – moderately calcareous, quartzose, poor – nil porosity. Siltstone: medium – dark grey, hard, blocky – sub fissile, common micromicaceous, weakly laminar – massive. Gas: 2-4units. 96/4/tr/tr/tr

f) **Adori Sandstone (1440.3 – 1473.2 mKB) -** Middle – Late Jurassic braided fluvial sediments. Sandstone with minor siltstone. Very fine sandstone with strong calcareous light brown cement at top of unit. Sandstone: Light translucent grey, very fine – coarse, friable – moderately well consolidated, nil – moderately calcareous, minor cement, common overgrowths and bit fractured quartz in part, fair porosity, no shows. Siltstone is dark grey, micromicaceous, weakly laminar. Gas: 1-3units. 86/11/3/-/-

g) **Birkhead Formation (1473.2 – 1567.2 mKB) -** Middle Jurassic fluvio – lacustrine sediments, volcaniclastic influx from the east occurs in the middle part of the unit. 1473.2 – 1501mKB Sandstone and siltstone interbeds, rare mudstone. Intermittent beds with high swelling clay content. Sandstone is light grey – off white, very fine – coarse, quartzose, loose – moderately well consolidated, common – abundant swelling clay, nil – good porosity. Siltstone is medium – dark green grey, moderately hard, common micromicaceous, minor arenaceous. Mudstone is carbonaceous, platy. Gas: 6-9U. 68/15/7/10/tr

   1501 – 1567.2mKB. Siltstone and sandstone interbeds, siltstone increasing to base of interval. Sandstone is light grey, very fine – medium, moderately consolidated, common white – light brown cement, common swelling clay, nil to trace visible porosity. Siltstone is: Medium grey – medium brown grey, arenaceous. Medium green grey, moderately hard, minor – common micromicaceous. Brown, sub platy, moderately hard – hard, carbonaceous, laminar. Gas: 3-20units. 72/16/7/5/tr.

h) **Hutton Sandstone (1567.2 – 1576.4 mKB) -** Early – mid Jurassic braided fluvial system deposited as a series of stacked channel sands. Quartzose sandstone with siltstone interbeds.

Sandstone: Off white – light grey brown, very fine – medium, abundant light translucent brown cement, loose – poorly consolidated, nil – poor visible porosity, poor – fair inferred porosity. Siltstone: Medium – dark grey brown, arenaceous, common – abundant mica, common coaly carbonaceous laminae, minor dark grey siltstone. Gas: 15units, 72/15/6/7/tr.

i) **Massive Hutton Sandstone (1576.4 – 1658 mKB) -** Quartzose sandstone with minor siltstone. Becoming generally coarser with depth. Sandstone is light translucent grey, rarely light translucent brown, predominantly medium – coarse, poor – moderately well sorted, loose – moderately well consolidated, trace garnet, poor – excellent inferred porosity. The sandstone has levels with abundant recrystallised quartz and overgrowths occluding porosity. Approximately 100% sandstone fluorescence to 1603mKB then decreasing. Siltstone is medium grey – green grey – light brown, commonly moderately hard, weakly laminar, siliceous and micromicaceous. Minor arenaceous siltstone with common mica and minor carbonaceous laminae. Gas: 100units. 66/18/10/6/tr.

1.2.2 Hydrogeology

With respect to hydrogeology, the rock column of the Eromanga and Cooper Basins can be broadly subdivided into aquifers and confining beds (aquitards and seals). Aquifers are porous and permeable units that are able to store and transmit water and are generally analogous to the petroleum reservoirs in that they have storage capacity for fluids as well as permeability which enables the passage of fluids through them. In several instances, porous-permeable units are both aquifers and petroleum reservoirs.

Confining beds (aquitards) are units that impede the movement of water, and in general have low hydraulic conductivities or permeability. Aquitards can have such a low conductivity that no fluid permeates them under the pressure conditions inherent in that part of the basin. Seals are proven by their ability to trap and hold gas under pressure. The Birkhead-Hutton formation with its extremely low permeability is one such aquitard, it has a permeability of 1-10 millidarcys (mD) and an impermeable shale barrier located immediately below and above the formation. The Bridgeport oilfield operates within this Birkhead-Hutton formation.

The Hutton Sandstone is regionally extensive in the Eromanga basin which “is the largest of the main [Great Artesian Basins] and extends across Queensland, New South Wales, South Australia and the Northern Territory (650,000 km2 in area in Queensland)”. This area has been regionally mapped and based on some reservoir modelling indicates there has been no material water volume change in the Hutton sandstone in the area relative to the total volume of the aquifer and well below any drawdown trigger threshold as defined by the *Water Act 2000*.

In addition, it should be noted, within this area, <u>there are no aquifers with environmental values or other receptors (water bores, groundwater dependant ecosystems/springs, or exploration holes) drilled to the depth of the field reservoir.</u>

It should be emphasised that all Bridgeport wells in this oilfield are drilled at or below 1500 mts which is well below the drawdown level of the irrigation and potable water sources. There is no evidence of water decline in any of the Inland wells, nor is there any decline anticipated elsewhere in the area of the field as a result of the Inland oil production. The Hutton Sandstone is a very large aquifer that contains good to excellent quality sands that allow liquids to readily move up-dip to displace any produced oil. This situation is common in the case of oil fields with good aquifer support, which was verified in this field by reservoir simulation work in 2006.

The conventional oil wells at the Inland Oilfield extract oil and water from aquifers of the Great Artesian Basin (GAB), particularly the Hutton Sandstone and the Murta Sandstone. The Hutton Sandstone is the predominant aquifer in the GAB providing approximately 60 per cent of the total volume of groundwater withdrawal.

1.2.3 Aquifers Affected by Inland Operations

The following information is an extract from the original Bridgeport Underground Water Impact Report (UWIR) available on the DEHP web site.

The aquifer volume in the immediate area of the Inland Oilfield is substantial. The Hutton Sandstone is more than 130 metres (m) thick and the total pore volume solely within the Petroleum Lease (40 km^2) is approximately 600,000 Mega Litres (ML). This is in comparison with the amount of water (2,020 ML) and oil (600 ML) produced from the reservoir to date. The nominal area of affected aquifer relates to the Hutton reservoir (Central 5) with less than 1/200th of total current water production coming from the Birkhead (Central 4) and other secondary reservoirs (McKinlay & Namur – Central 3). There is no evidence of water decline in any of the Inland wells, nor is there any decline anticipated elsewhere in the area of the field as a result of the Inland oil production. The Hutton Sandstone is a very large aquifer that contains good to excellent quality sands that allow liquids to readily move up to displace any produced oil. This situation is common in the case of oil fields with good aquifer support, which was verified by reservoir simulation work carried out in 2006.

Due to the regional extent of these aquifers, there is excellent pressure support during the entire period that oilfield production has occurred. ***A drop in water levels has not been observed, and indeed, a rise in the Oil Water Content has been seen during production operations.*** Water level is monitored through producing oil wells. When a producing well reaches an uneconomical percentage of water cut, it is because the water level has risen locally around the well. Future infill wells are located to optimise oil production and minimize the percentage of water produced.

The absence of producing water bores in the area of influence of PL 98 means that there is no feasible way to assess changes in water levels. Bridgeport does measure water quality in the evaporation ponds quarterly as per DEHP operating conditions for the permit. It has in the past produced from the Hutton Sandstone (Central 5) and the Namur Sandstone Member (Central 3). Other water bores in the database access the Quaternary sediments, the Winton Formation and the Glendower Formation at depths shallower than 500 m. **None of the bores are completed across units produced in the Inland Oilfield.** The table below provides the distances of the surrounding bores from the PL 98 tenure and the Inland Oilfield. On the basis of the distance of these water bores from the field and the fact that these bores do not access the Central 3, 4 or 5 units, there is no means of using these bores or the Inland wells to infer any sort of aquifer interactions or impact on effective pressure.

Table 1: Identified Water Bores at PL 98

Bore	Formation	Distance from PL 98 (km)	Distance From Inland Oilfield (km)	Comment
4396	-	7.4	14	
7740	Quaternary,Glendower,Winton	6.7	13.4	
8047	Quaternary,Glendower,Winton	5.6	6.8	
12552	Quaternary,Glendower	18.6	20	
12593	Quaternary,Glendower	10.9	11.7	
13021	Quaternary,Glendower,Winton	6.7	13.4	
13114	Quaternary,Glendower,Winton	13.3	15.3	
13544	Quaternary,Glendower	9.8	11.3	
13743	Quaternary,Glendower	7	8.5	
14209	Quaternary,Glendower,Winton	16	17	
16489	Quaternary,Glendower,Winton	7.4	8.6	
23695	-	14.5	16.1	CUDDAPAN-1: plugged back to surface, next plug at 344 m
36307	Quaternary,Glendower	13.1	15.8	
51804	Quaternary,Glendower	15	16.1	
69179	-	3.3	8.2	
69562	Glendower	3.6	10.3	
93025	-	8.6	9.5	
93999	-	8.2	9.7	
100199	-	in permit	in field	INLAND-1: shut in oil well
100226	Winton	9.6	12	MORNEY-1: Plugged back to 230 m
118000	-	11.6	13.8	
118622	-	12.8	17.7	

2. Legislation

The primary legislative requirements for the management of groundwater with respect to petroleum tenure holders for PL98 are summarised below.

2.1 Petroleum and Gas (Production and Safety) Act 2004

The *Water and Other Legislation Amendment Act 2010* amends the *Water Act 2000* (Water Act) and other relevant legislation with the aim of improving the management of impacts associated with groundwater extraction that form part of petroleum activities. These amendments transfer the regulatory framework for underground water from the Petroleum Act 1923 and the Petroleum and Gas (Production and Safety) Act (P&G Act) to the Water Act.

The P&G Act originally provided all rights of water extraction to a petroleum activity. However, through recent updates of the P&G Act and the Water Act, a petroleum tenure holder has an obligation to identify impact, establish baseline conditions and maintain groundwater supplies in private bores in the vicinity of petroleum operations. Where a bore owner can demonstrate reduced access to groundwater supplies, or a reduction in beneficial use class due to water quality changes, as a result of petroleum operations, "make good" provisions are available to address the loss incurred by an affected bore owner. Under the P&G Act, the make good obligation for affected bores also applies to petroleum tenure obtained under the Petroleum Act 1923 and are further defined in the Water Act.

2.2 Water Act 2000 (Qld)

The Water Act 2000 (Qld) (as amended 2010):

- Provides a comprehensive regime for the planning and management of all water resources (including vesting to the State the rights over the use, flow and control of all surface water, groundwater, rivers and springs) in Queensland.
- Regulates water use and the obligations of petroleum tenure holders in relation to groundwater monitoring, reporting, impact assessment and management of impacts on other water users.
- Provides a framework and conditions for preparing a Baseline Assessment Plan and outlines the requirements of bore owners to provide information that the petroleum holder reasonably requires to undertake a baseline assessment of any bore.
- Sets out the process for applying for a Water Licence (where water is utilised outside of a petroleum lease or not on adjacent land owned by the same person).
- Sets out the process for assessing, reporting, monitoring, and negotiating with other water users regarding the impact of petroleum production on aquifers.

2.3 Other relevant water regulations

The following statutes are also applicable to the oil production within PL98:

- Environmental Protection Act 1994 (Qld)
- Environmental Protection (Water) Policy 2009 (Qld)
- Great Artesian Basin Resource Operations Plan 2006
- Water Resource (Cooper Creek) Plan 2000 (Qld)

3. Water Production History

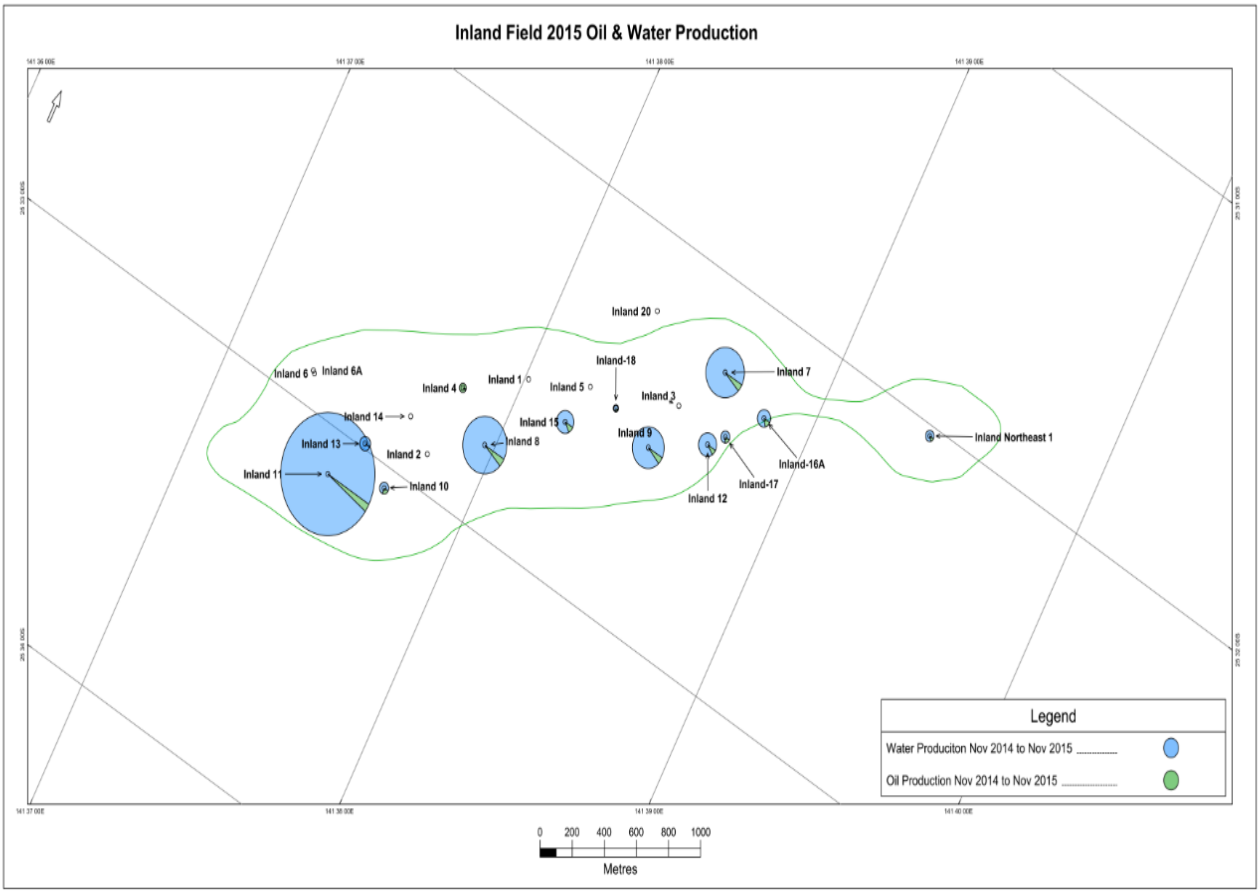
3.1 Well Histories

Inland Oilfield was brought on line by the previous operators IOR in September 1994 and the associated water production did not begin until July 1995.

Bridgeport acquired this asset from IOR Limited in April 2011. The previous **endorsed** UWIR included pre 2012 figures form IOR and started the reporting period in November 2012. Since then there has been an annual updates. For this UWIR reporting period 2015-2018 approximately 628.76 mega litres (ML) of associated water will be produced (see Table 2 below). The reporting of the total volumes of water produced complies with the requirement in S376 (a)(i) of the *Water Act 2000* (Water Act) and the first approved Underground Water Impact Report (UWIR) issued by Bridgeport in August 2012.

Bridgeport Energy has been operating in the area since the 2009 producing conventional oil at Inland oilfield from approximately 15 wells at Inland and 11 wells at Utopia. As production from our conventional oil reserves declines, the development of previously uneconomic oil reservoirs is necessary to extend the supply life of petroleum from the region. Figure 3 below depicts the oil water content in the wells at Inland oilfield. Operating in a Sustainable manner is an integral part of Bridgeport Energy's operating ethos. We are committed to responsibly managing our environmental impact, working in partnership with the communities in which we operate and managing our business in a sustainable and diligent manner.

Figure 3 – Oil water content by well PL 98



3.2 Methods for Measuring Extracted Water Volumes

Conventional oil production is unlikely to deplete local or regional groundwater supplies due to large vertical separation and low permeability between the overlying aquifers and the sandstone oil reservoirs as depicted in section 1 above. Measurement of oil in produced water is required from an operational point of view, because process optimisation is increasingly being implemented by operators so that less oil is discharged, less chemicals are used, process capacity is increased, and oil and gas production is maximised.

The estimated associated water production in the original approved UWIR report was based on records from IOR for the period September 1995 to April 2011. Since ***April 2011, Bridgeport Eromanga*** has measured oil and water production from each oil well by utilising a chemically treated dip stick in a test tank. Bridgeport Energy's monitoring strategy is based on three primary parameters. These are:

- Formation water production history,
- reservoir oil/water level depth and
- water quality.

By closely monitoring and keeping good records of these parameters, Bridgeport Energy has developed a monitoring strategy that meets the requirements of Section 376(f) of the Water Act. The following section provides more specific details of how these parameters are collected.

In order to effectively evaluate the impact of water extraction on the aquifer, it is vital to know the volume of water that has been extracted. As such, Bridgeport Energy has implemented a water production monitoring system that allows the volume of water that has been produced from the reservoir to be calculated. The following is a summary of this system.

Within the field, each well is flow tested into an isolated test tank. After a settlement period, the contents of the tank are volumetrically measured by means of a dip-stick and water-indicating paste. Volumes of both produced oil and water are obtained from this measurement as per S378(a):

- With the volumes and the time period known, a daily production rate for oil and water is calculated as per S378(c).
- Daily water rates from all wells are then cross-referenced with daily uptime data and from this, the quantity of water produced by a given well in a given day can be calculated as required by S378(b).

As a result of this process, historical water production statistics are available for the field and on a per-well basis. Consequently, Bridgeport Energy has a thorough understanding of the quantity of water that has been extracted as well as extraction rates throughout the field's history.

Produced water from the separator is produced to a wash tank (skimmer) where coalesced oil is skimmed off to the separator. From the wash tanks, produced water flows into an interceptor pond where any bypass oil is regularly skimmed off. It then passes from this pond to a series of three evaporation ponds. The water quality in these ponds is tested quarterly including ultra-sensitivity test for benzo(a)pyrene as required by the landowner for his cattle watering QA requirements. The following table 3 represents an update of all wells drilled within the Inland Oilfield to October 2015.

3.3 Underground water level depth

The second parameter that Bridgeport monitors is the depth of the underground water level. Since a significant portion of the requirements under S376 of the Water Act pertain directly to the relationship between water extraction and underground water level depth, this parameter is also essential. Bridgeport has adopted two chief methods of evaluating this aspect.

The first of these is through analysis of current wells and their production status. As has been described above, the general trend for the underground water level is that it rises as oil is depleted. Consequently, when an existing well waters out (ceases to produce oil and only produces water), it can be inferred that in the immediate localised area, the underground water level depth has risen to the depth of the well's perforations. In Bridgeport's case this can be 1.4 kms from surface. The second of these is through identification of the oil/water contact in new wells as they are drilled.

When new wells are drilled, the oil-water contact at the time of drilling can be identified by log analysis. Since the depth of the oil/water contact is defined as the top of the aquifer water level, identification of the oil/water contact through log analysis also allows aquifer water level depths to be understood. As with the water production history, maintaining good records of these parameters as they become available has resulted in a firm understanding of the original reservoir water level depth as well as how this depth might change over the production life of the Inland Oilfield as water displaces oil.

Table 2 Well Histories

Well name	History
Inland-1 (Suspended)	• Drilled in June 1994 and completed in July 1994 in the Namur Formation and the Hutton Sandstone • March 1999, a swab test over the Namur -found not to be producing • Namur was reperforated in January 2001 and in February 2001, the Namur was tested and flows 211 bpd with 100% water cut • March 2002, the Namur was isolated in the annulus and the Hutton reopened • May 2002 Hutton Test: 797 bpd 99.6% water cut • June 2002 a downhole fault could not be resolved • September 2002 the well was suspended
Inland -2 (Suspended)	• Drilled in 1995 and completed in May 1995 over the Hutton • 2002, the well watered out • June 2006, plug set over the Hutton and the well was perforated in the Birkhead • Shut in November 2006 • August 2008 fracked • December 2008 shut in
Inland -3 (Suspended)	• Drilled in 1995 and completed in June 1995 over the Hutton Sandstone • December 1995, Namur perforated. • February 2013 parted rod, well was deemed not economical for a work over. Shut in.
Inland -4 (Producing)	• Drilled in 1996 and completed in February 1996 in the Hutton Sandstone • In 2001, the well watered out • In June 2006, Hutton was plugged off and Birkhead was perforated. Extremely low productivity. • In August 2008, fraccing was conducted to increase productivity from the Birkhead. Still producing to date • Drilled in October 1996 and plugged and abandoned
Beal-1 (Abandoned)	• Drilled in October 1996 and plugged and abandoned

Well name	History
Inland-5 (Suspended)	• Drilled in 1996 and completed in November 1996 in the Birkhead and Hutton sandstones • The well watered out in 2002 • February 2003 – Bridge plug was set plugging off the Birkhead and Hutton and the McKinlay formation was perforated • 2006 production stopped: Records of oil rate of 15 bopd and little water prior. Both oil and water rates drop to 0. No reasons found in the IOR records. Field staff advised that the well keeps pumping off. Shut in since 2013.
Inland-6/6A (Abandoned)	• Drilled in Oct 1996; side-tracked in Nov 1996 and plugged & abandoned in mid Nov 1996.
Inland-7 (Producing)	• Drilled in 1997 and completed in 1997 in both Birkhead and Hutton • May 2013 work over, tubing and rods were replaced • Still producing to date
Inland-8 (Producing)	• Drilled and completed in 1997 in the Hutton Sandstone, online with 13 bpd of associated water • January 2001 the water cut went from 90% down to 75% after 6 months • August 2003 Hutton Test at 397 bpd associated water • A series of work-overs throughout 2013 and 2014 to keep Inland-8 pumping
Inland-9 (Producing)	• Horizontal well completed in April 2000 in the Hutton • Still producing to date
Inland-10 (Producing)	• Completed in March 2001 in the Hutton • Workovers in 2005 and 2012 • Still producing to date
Inland-11 (Producing)	• Completed in February 2001 in the Birkhead and Hutton • Workover to replace ESP in 2013 • Still producing to date
Inland-12 (Producing)	• Horizontal well drilled and completed in June 2002 • Workovers in 2006 and 2013 • Still producing to date
Inland Northeast-1 (Producing)	• Drilled in July 2002 and completed in August 2002 in the Hutton • Production rate declined rapidly. • Workover in September 2015, online October 2015
Inland-13 (Suspended)	• Completed May 2004 in the Hutton • This well was watered out and been shut in. Awaiting re-completion in the Birkhead.
Inland-14 (Producing)	• December 2006 completed in the Hutton; • Suspended due to no production. • Workover October 2015, online November 2015
Inland-15 (Producing)	• December 2006 drilled and competed in the Hutton • Workovers in 2007, 2009, 2013 and 2014 • Still producing to date
Inland-16 (Producing)	• Drilled in January 2013 and completed in April 2013 over the Hutton sandstone • Productivity has declined rapidly due to suspected formation damage • Workover in September 2015, still producing to date
Inland-17 (Producing)	• Drilled in January 2013 and completed in March 2013 over the Hutton sandstone • Productivity has declined rapidly due to suspected formation damage • On production every 2 days due to low productivity • Workover in September 2015

Well name	History
Inland-18 (Producing)	• Drilled in January 2013 and completed in April 2013 over the Hutton sandstone • Productivity has been low ever since completion due to suspected formation damage • Workover in October 2015
Inland-20 (Suspended)	• Drilled in December 2013 and completed in January 2014. No production. • Re-completed in February 2014 and produced only water. • Suspended

3.4 Proximity of overlying and underlying aquifers

The key aquifer unit in the Bridgeport Inland Oil Field Project Area is the Hutton Sandstone. The vertical subsurface distance from ground elevation is greater than 1.4 km. The geological cross sections provided in Figure 1 and 2 above illustrates the vertical thickness of stratigraphy, which separates the key Great Artesian Basin (GAB) aquifer from the targeted oil measures. The general range of stratigraphic thickness is 150-250 m.

Regional communities and landholders extract water from the shallow alluvial and sedimentary aquifers and the upper formations of the Eromanga Basin. Water in the shallow aquifers is moderately saline whereas the Eromanga Basin aquifers provide better water yields and quality. The Cooper Basin aquifers are not accessed by regional communities and landholders due to their great depth and the availability of shallower, more economical groundwater resources.

There are no drinking water aquifers or other environmental value aquifers from the Hutton Sandstone in our area of influence, as detailed throughout this document.

The closest bore is 14 kms away and is drilled at 31 meters. The Inland Field Project area is not located near the recharge beds area for the GAB, the GAB recharge area is commonly defined as the area where the GAB sandstone aquifer formations sub-crop or outcrop on the eastern margins of the GAB. The outcrop is approximately 750km, towards the Surat Basin, which is outside the Inland Oil Field Project Area and therefore the project area is not near the recharge springs or watercourse springs.

The wells that currently produce within the Inland Oil Field Project area continue to produce water from the Hutton Sandstone and the pressure readings indicate that there is a constant aquifer recharge. This is also detailed in the PL 98 UWIR (updated 2015) constant aquifer recharge assists with the oil production that is currently producing from the Inland Oil Field Project. Therefore there is no likelihood of reduction or loss of baseflow contribution from groundwater to rivers and creeks hence no impact on to the aquatic ecology of the surface water ecosystems.

The cumulative water production for the existing wells November 2015 – December 2018 in the Inland Oilfield is depicted in the Tables and bar charts below. The raw data is contained at Appendix B. Our forecasts to December 2018 are at table 5 below and figures 4, 5 and 6 depict the actual and cumulative water production 2015-2016. As this UWIR will be reviewed in November 2016 future and actual fires will be updated at that time.

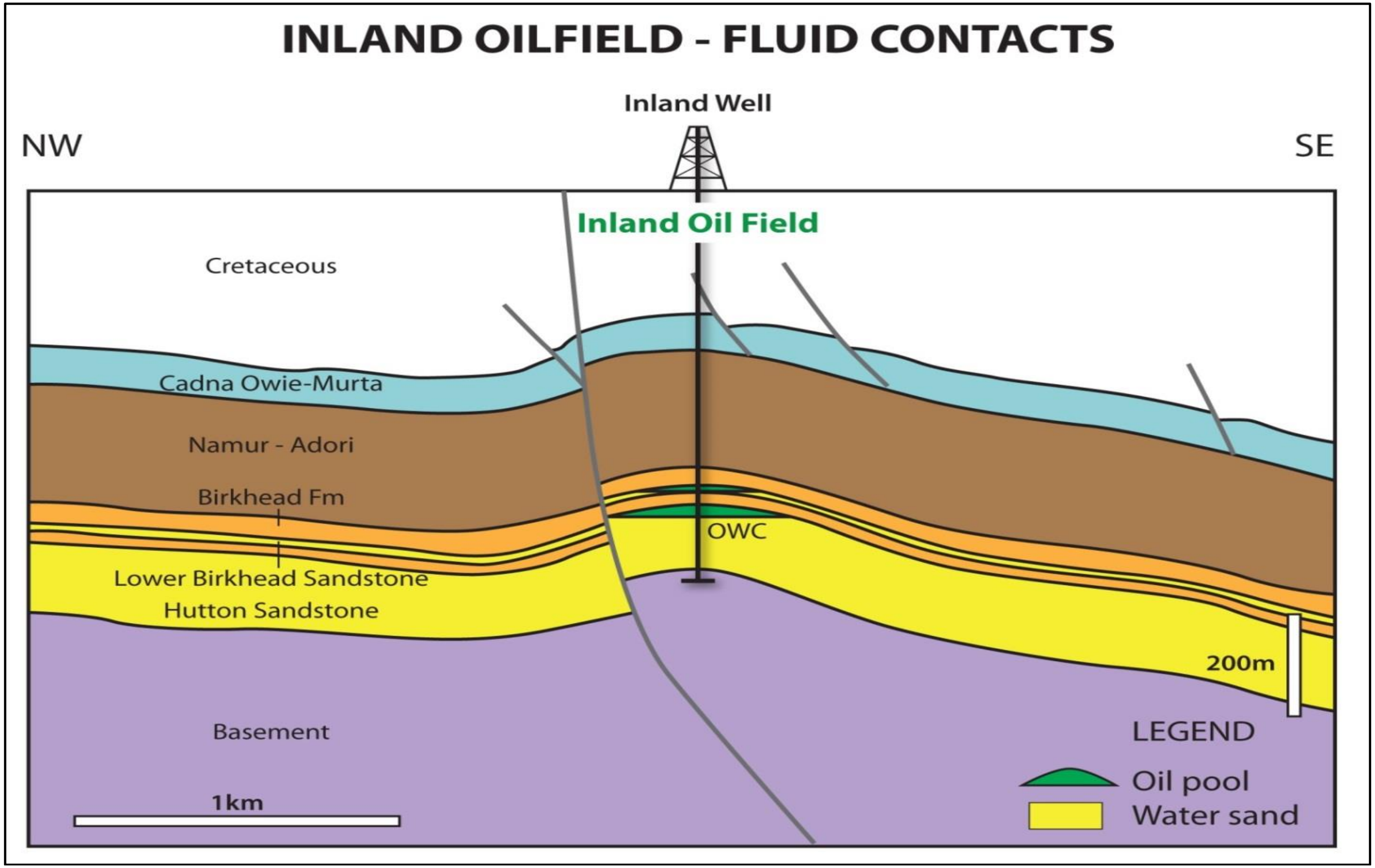


Figure 4: Schematic of Fluid Contacts in the Inland Oilfield

Schematic showing the relatively small upper part of the Hutton aquifer contains the oil pool. The extensive nature of the water-filled sandstone is also evident.

Table 3 – Cumulative Water Production (ML) to Nov 2018

Well Name	Cumulative Water (ML) Nov 2012 - Dec 2014	Cumulative and Forecast Water (ML) Jan 2015 - Nov 2018
Inland 1	0	0
Inland 2	0	0
Inland 3	0	0
Inland 4	0.18	0.16
Inland 5	0	0
Inland 7	22.23	56.21
Inland 8	25.19	89.2
Inland 9	22.25	55.75
Inland 10	1.65	3.25
Inland 11	124.62	295.56
Inland 12	6.055	11.15
Inland 13	5.18	0
Inland 14	8.302	49
Inland 15	1.434	11.38
Inland NE-1	9.068	38.71
Inland 16A	5.73	9.299
Inland 17	3.747	4.86
Inland 18	6.055	4.23
Total	**241.691**	**628.759**

3.5 Groundwater Dependent Ecosystems

The review of Environmental Values included the Groundwater Dependent Ecosystems (GDEs), groundwater users and social and cultural environmental values. Within Bridport operating tenements there are no endangered regional ecosystems 10 kms from the boundary of PL 98.

The closest State forest is the Welford National Park, near Jundah which is 98 kms north east from PL 98. Similarly no GAB springs were found within the tenement, the closest GAB discharge spring is approximately 90 kms away.

3.6 Environmental Values

The Queensland's Wild Rivers legislation was repealed in August 2014 and the 13 rivers in Cape York and in the state's western Channel Country will now be protected under the new Regional Interest Planning Act 2014 to prevent inappropriate development going forward.

Under this new framework, planning decisions will now be made through either local government planning schemes, or regional interest development approvals at the state level, to reduce complexity for development and maintain environmental values. Bridgeport Operations on PL 98 continue to comply with world best practice and the requirements of Environmental Approval conditions.

Water quality at Inland has been consistently in compliance with limits for ANZECC environmental quality, and drinking water limits as well as Environmental licence conditions. The ESA map below depicts the geographic location of PL 98 within the identified environmentally sensitive areas. It's notable that no ESAs of category A B or C exist within the tenement boundary or 5-10 kms in diameter of the boundary see figure 5 below.

The Hutton Sandstone is not a reliable groundwater source due to its discontinuous distribution and generally poor water quality. The nearest operational bore used by the landholder for cattle watering is Cuddapan Bore 8 (bore ID#15898) this is 14km away from the Inland Oil Field Project Area and is sunk at a depth of 31.7 metres. The Hutton depth is approximately 1,448 metres (True Vertical Depth) TVDSS from sea level and the pressure at this depth is approximately 2,250psi. The Hutton provides pressure support to be able to deliver oil to surface.

For the Inland Oil Field Project area there is only one aquifer which is the Hutton Sandstone (GAB). The Hutton is confined between the Birkhead Formation and the Poolowanna Formation; both of which are aquitards. The drilling and production activity at the Birkhead would not interconnect with "another" aquifer, whereby Bridgeport defines that "another" is 'greater than one'. Consequently there is no other aquifer that connects the target oil producing Birkhead Formation other than the one, the Hutton Sandstone (GAB) aquifer.

The overlying formation is known as the Birkhead Formation within the Inland Field. The Birkhead conformably overlies the Hutton sandstone. The sand unit was deposited within a NE trending fluvial meander belt running along the Inland structure. The Birkhead is bounded by upper and lower shales seals.

The underlying and main oil and water producing formation within the Inland Field is known as the Hutton Sandstone Formation within the Inland Field. The Hutton was deposited in a high energy environment. The sands exhibit good reservoir quality and are the main producing reservoir within the Inland Oil Field. The Hutton sand units are each separated buy thin shale seals which control field drainage. Petrophysical analysis commonly estimates average porosity at 10-15% and permeability ~150md. The average hydraulic conductivity is 0.1 - 2m/d and transmissivity 100 - 150m2/d, specific storage 3x10-6/m.

These parameters presented above are based on literature reviews.

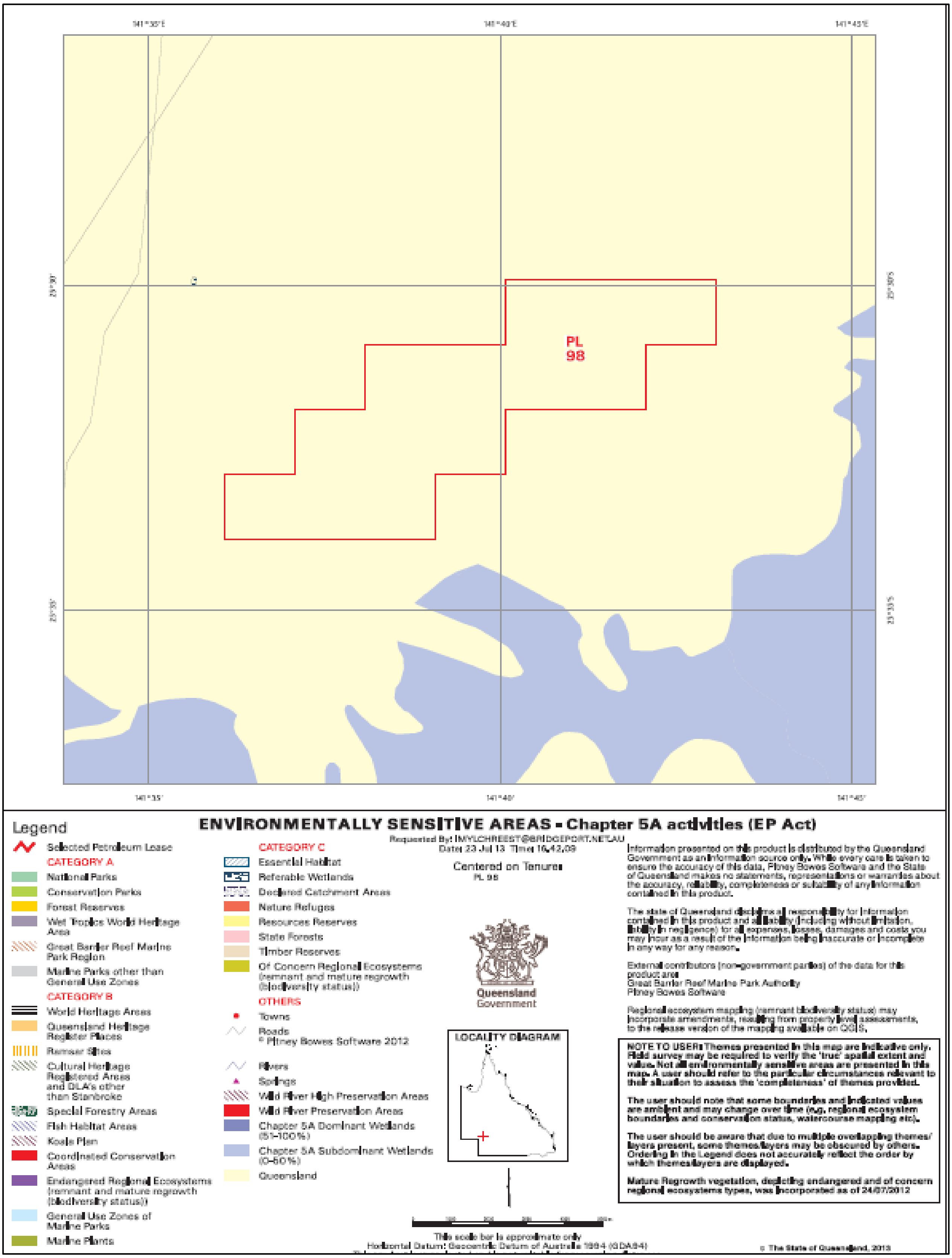


Figure 5 – Environmental Values at PL 98

Figure 6: Bubble map showing relative water production from each well (to Dec 2016)

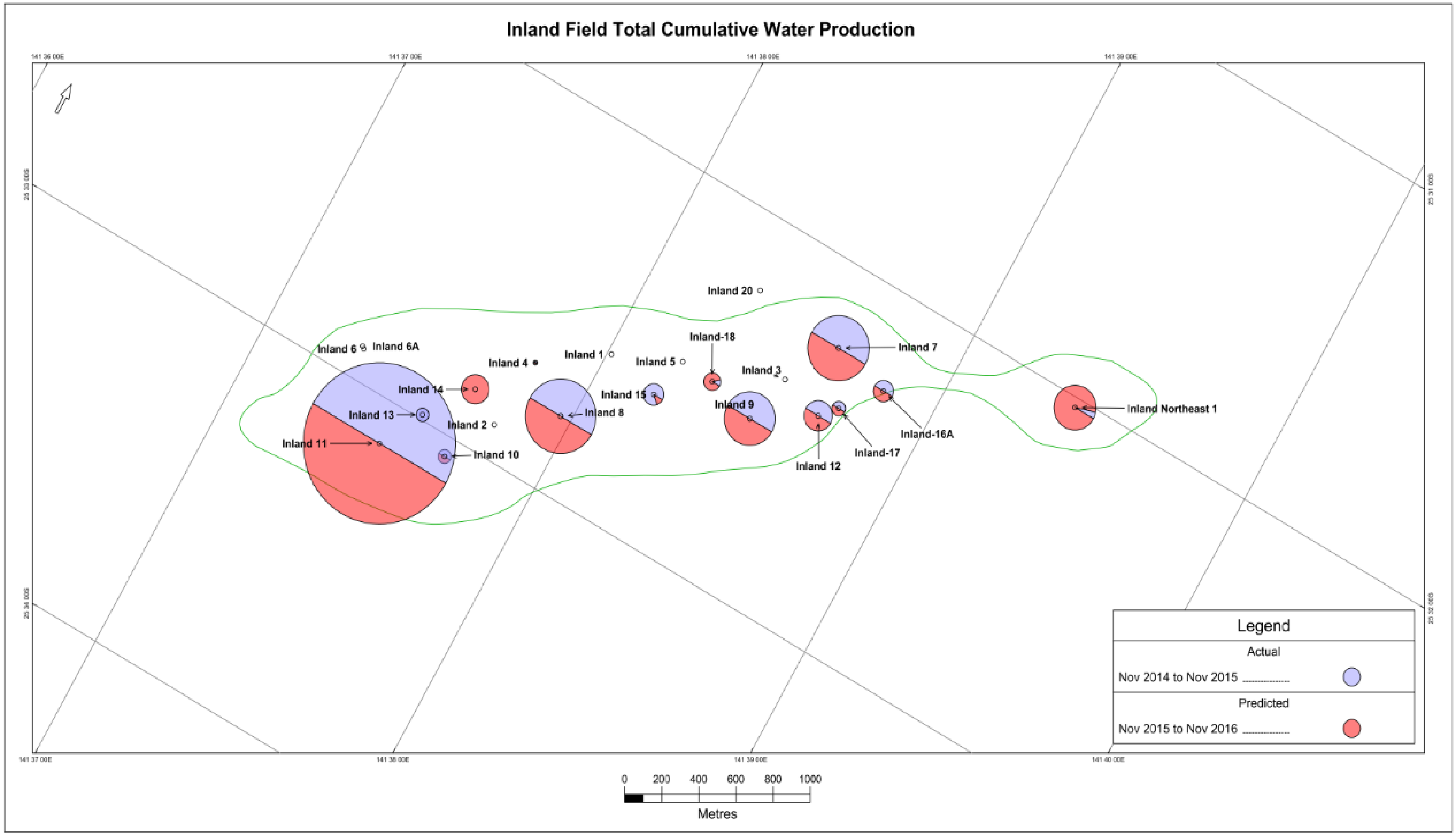


Figure 7 – Inland Oilfield Annual Water Production

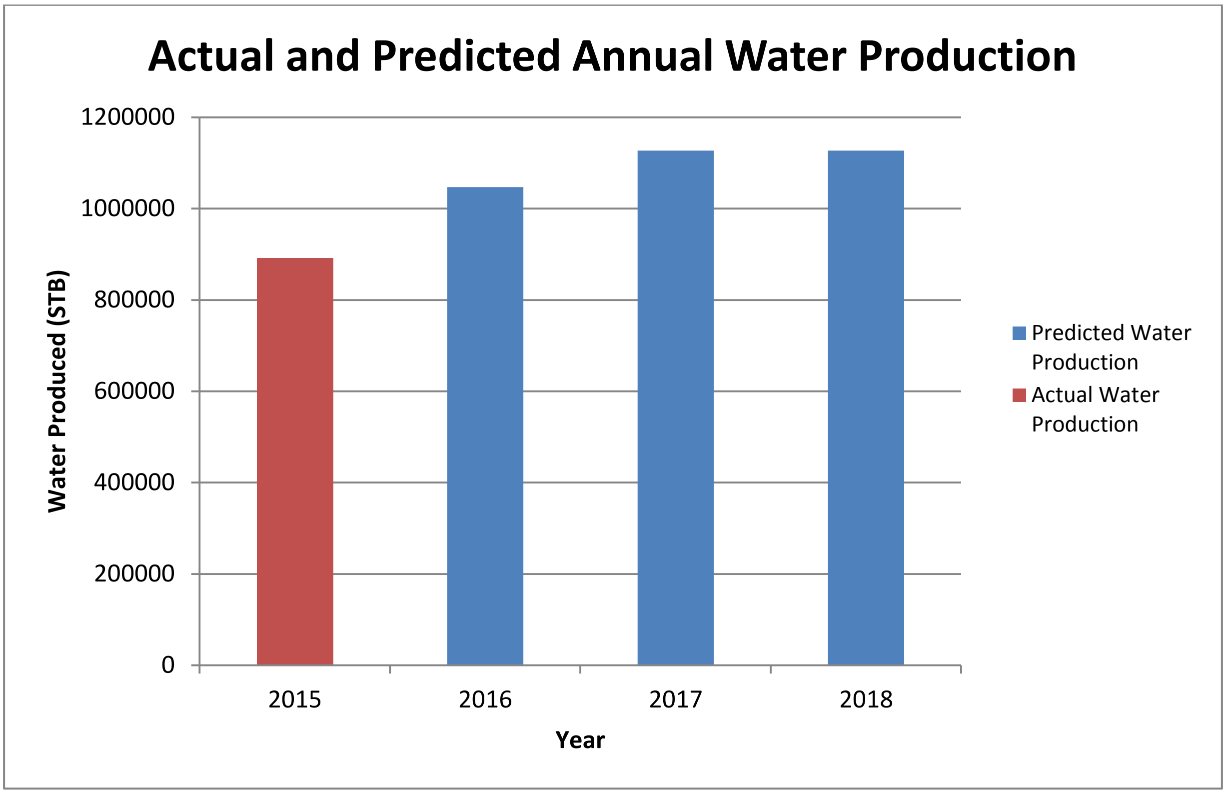


Figure 8 - Water Production Nov 2014 to Dec 2015 by Well

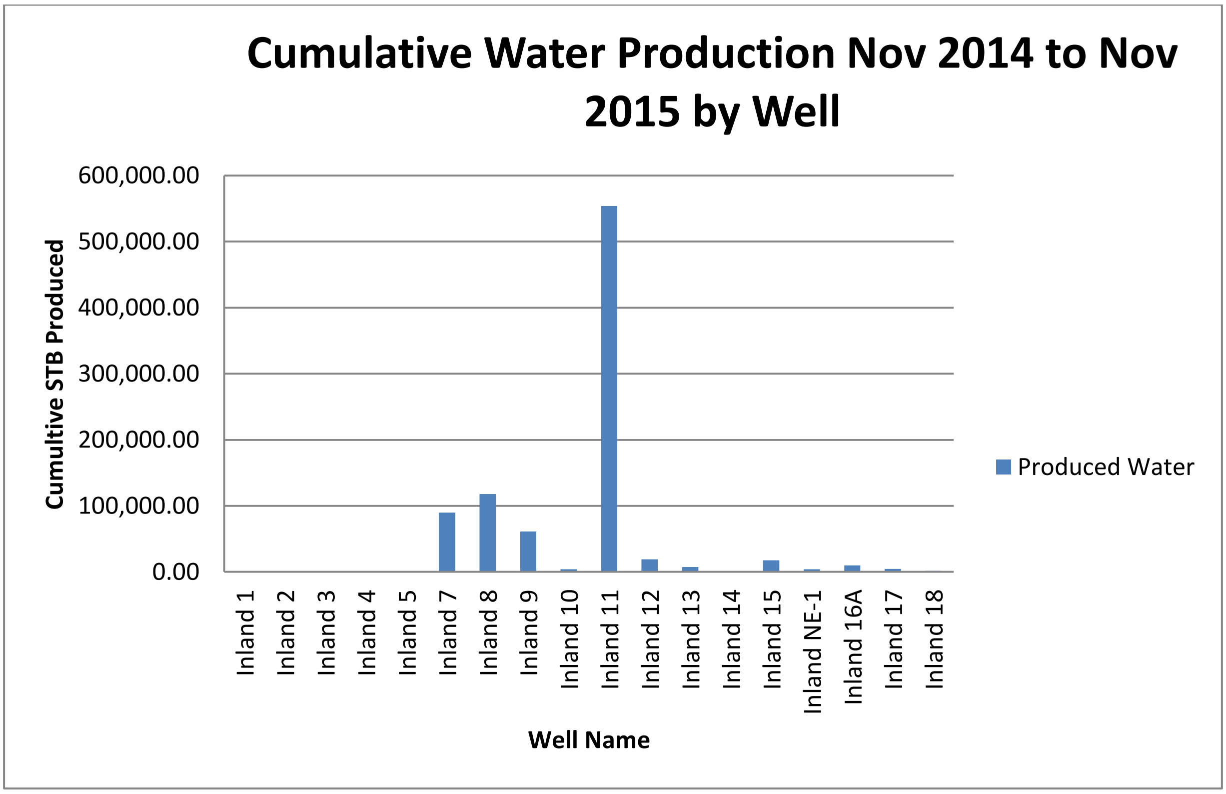


Table 4 – Forecast Water Production 2016 (Megalitres)

Well Name	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Annual
Inland 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inland 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inland 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inland 4	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Inland 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inland 7	1.20	1.13	0.98	0.08	1.21	1.81	1.40	1.34	1.31	1.29	1.28	1.29	14.32
Inland 8	1.63	1.12	0.00	0.19	2.05	1.94	2.06	2.00	1.95	1.92	1.90	2.02	18.78
Inland 9	0.78	0.77	0.73	0.66	0.65	0.66	0.73	0.69	1.09	0.88	1.02	1.05	9.71
Inland 10	0.05	0.08	0.08	0.05	0.05	0.09	0.06	0.05	0.00	0.05	0.04	0.05	0.64
Inland 11	7.46	7.75	7.81	6.30	6.70	7.71	5.51	8.06	7.79	7.57	7.54	7.91	88.09
Inland 12	0.22	0.24	0.27	0.23	0.22	0.27	0.32	0.32	0.20	0.28	0.28	0.21	3.06
Inland 13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Inland 14	0.48	0.49	0.49	0.45	0.49	0.48	0.49	0.48	0.49	0.49	0.48	0.49	5.80
Inland 15	0.36	0.36	0.36	0.37	0.37	0.37	0.39	0.39	0.39	0.39	0.39	0.39	4.53
Inland NE-1	1.06	1.10	1.10	0.99	1.10	1.06	1.10	1.06	1.10	1.10	1.06	1.10	12.90
Inland 16A	0.14	0.14	0.13	0.14	0.13	0.13	0.13	0.13	0.06	0.06	0.04	0.31	1.55
Inland 17	0.05	0.03	0.04	0.03	0.02	0.02	0.03	0.04	0.03	0.03	0.04	0.33	0.70
Inland 18	0.17	0.08	0.21	0.19	0.14	0.19	0.18	0.15	0.20	0.17	0.08	0.15	1.91
Total	**13.61**	**13.29**	**12.20**	**9.67**	**13.14**	**14.72**	**12.39**	**14.70**	**14.62**	**14.24**	**14.14**	**15.30**	**162.02**

4. Water Monitoring

4.1 Monitoring

The Ministerial Approval Conditions for the PL 98 UWIR on 21 November 2012 specified monitoring of produced water:

i. All monitoring required of the responsible tenure holder under the UWIR must be undertaken by a suitably qualified person.

ii. All laboratory analyses and tests of monitoring undertaken under the UWIR must be carried out by a laboratory that has NATA accreditation for such analyses and tests, except as otherwise agreed to in writing by the Chief Executive.

iii. The methods of groundwater sampling required by the UWIR must comply with the latest edition of the Queensland Monitoring and Sampling Manual, AS/NZS 5667:11 1998 Water Sampling Guidelines – Part 11 Guidance on sampling groundwater, and the Australian Government's Groundwater Sampling and Analysis - A Field Guide (2009:27 GeoCat #6890.1) as relevant and as may change from time to time.

With regards to ground water, Bridgeport Eromanga has implemented monitoring programs that are adequate to collect the data required to effectively monitor the relevant underground water properties and thus ensure there are no critical gaps in data.

Consequently, it has not been deemed necessary to conduct any supplementation of Bridgeport's existing monitoring programs and further given that the nearest water bore is over 14 km to the southwest from the Inland Oilfield, this is considered to be too far to detect changes in any of the reservoirs/aquifers.

The monitoring strategy currently being employed by Bridgeport Eromanga includes acquisition of data relating to the volumes of water extracted from the reservoir. This strategy allows Bridgeport to understand rates of water extraction over time but does not measure changes in the aquifer's water level over time because the regional aquifer is so large (extending well beyond the lease boundary). The regional aquifer is more than *1,300 times larger than the volume of the oilfield*.

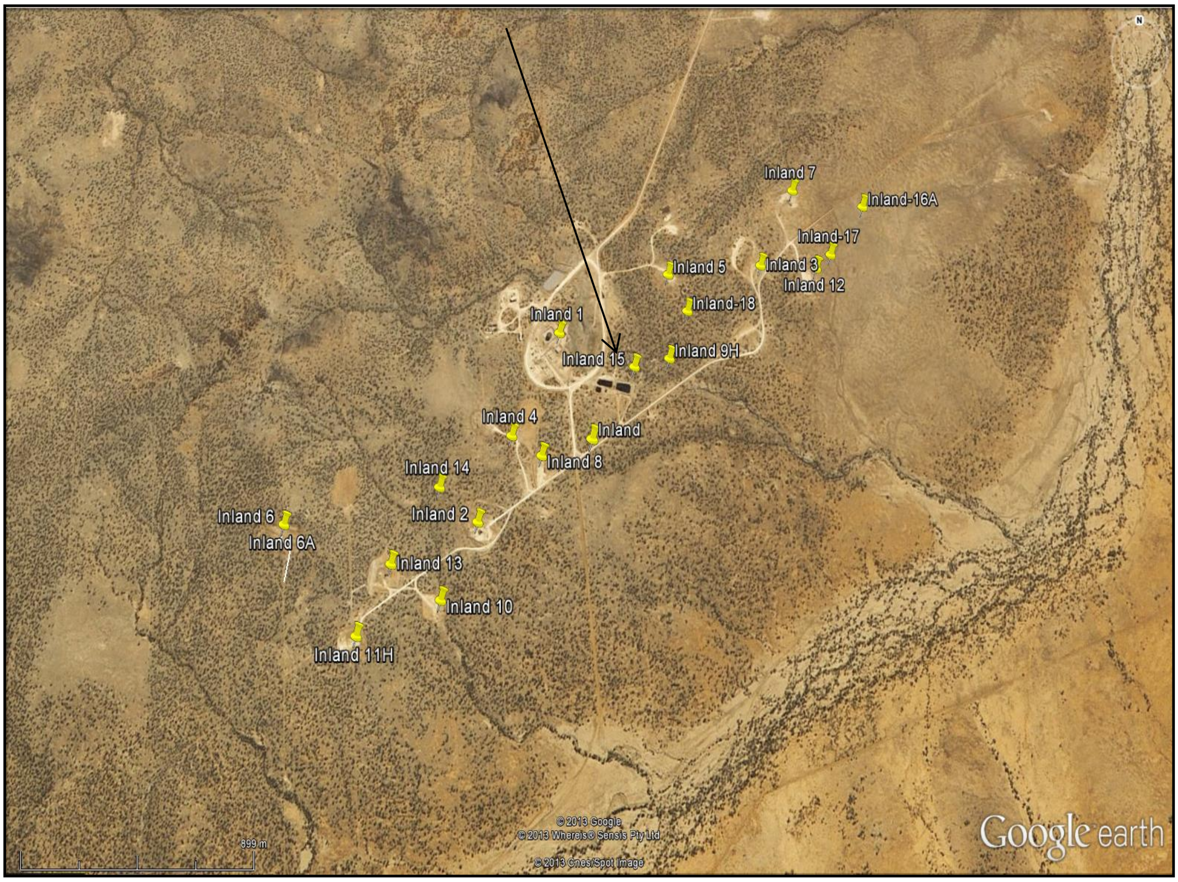
In addition to the subsurface aquifer water levels, large amounts of data are acquired pertaining to water quality and handed to the landowner. This data acquisition is undertaken on a quarterly basis and as such, the water quality can be assessed at various stages throughout the production life. Having the water quality analysed at these different stages, facilitates historical comparisons of water quality and underground water extraction. These comparisons can significantly enrich the levels of understanding of the impacts of underground water extraction on aquifer water quality and if any impact does exist, this process will ensure that it can be easily identified.

4.2 Water Quality

The final parameter that comprises Bridgeport's monitoring strategy is that of water quality monitoring in the evaporation ponds these can be seen on the aerial photo in figure 9 below. In accordance with the Environmental Authority conditions associated with PL 98, Bridgeport Eromanga performs quarterly analyses of its produced water. The samples are sent to a NATA registered laboratory ALS or Bureau Veritas where they are analysed for a wide range of contaminants including oils, TDS, pH, metals, PAH, phenols, chloride TPH/TRH and BTEX, as well as ultra-sensitive test for benzo(a)pyrene which are conducted for the landholder's cattle watering QA requirements.

With the results of these analyses, Bridgeport is able to consistently monitor the quality of its produced water and combined with the water production history, can also analyse changes in water quality for relationships with the quantity of water extracted.

Figure 9: Inland Oilfield with Evaporation Ponds visible



4.3 Cumulative Assessment of water already produced

Since Bridgeport Energy has been monitoring produced water quantity only since September 2012 the actual full year of records is based on 2013 onwards. The table below depicts the cumulative water per annum (2012 being represented by only 2 months).

Year	Cumulative Water (STB)	Cumulative Water (ML)
2012	143,266	22.78
2013	398,783	63.40
2014	940,187	149.47
2015	891,394	141.71
2016	992,827	157.84
2017	1,054,372	167.62
2018	1,054,372	167.62
Total	**5,475,201**	**870.45**

The produced water for the previous years has been reported in the UWIR 2012-13 and the UWIR update 2014-15. The Bubble map above represents the volumes of produced water to 2016 years per well.

4.4 Reporting Program

For water production monitoring, Bridgeport Eromanga provides water production statistics to the Queensland Department of Natural Resources and Mines on a six-monthly basis. For water quality, Bridgeport provides water samples to the landowner on a quarterly basis in compliance with the CCA requirements. For aquifer water levels, Bridgeport Eromanga obtains petrophysical data by reference as new wells are drilled. As the OWC movement is only constrained within the reservoir this form of data is not relevant to water extraction levels – this means that they do not change substantially over the 20 year life of a well.

Further reporting to the Queensland Office of Groundwater Impact Assessment (OGIA) has not been implemented as these regional aquifers **are well below any known extraction points for irrigation or domestic use, as detailed above.**

This UWIR will be updated annually as required with accurate water use and predictions for the following year recorded, any changes in the monitoring strategy, goals and site conditions will be reported. However predicted impacts are not anticipated to change as Bridgeport Operations of the Inland Oilfield have no material impact on the potable aquifers or aquifers of environmental value, no drop in aquifer pressure has been observed and as such our impact is minimal.

5. CONCLUSION

In accordance with sec.376 (e)(ii*) Giving the chief executive a …statement of whether there has been a material change in the information or predictions used to prepare the maps.*

Bridgeport Energy has stated elsewhere in this and other UWIR reports that we are operating at depths greater than the artesian water table. Although the Inland field is a mature oilfield with increasing water production and decreasing oil production, the total voidage volume of oil being replaced by water in the reservoir is insignificant relative to the total water volume in these deep reservoirs. Furthermore the size of the regional aquifer being 1300 times larger than the oilfield on PL 98 coupled with constant pressure from the wells implies our impact is insignificant.

The Bridgeport Energy UWIR approved November 2012 detailed and assessed the impacts of our oil operations in the Eromanga area of South West Queensland. Within the Bridgeport tenements, in this region, there are no Groundwater Dependent Ecosystems (GDE), significant groundwater users or social and cultural environmental values. Furthermore no GAB springs were identified in close proximity to the PL 98 tenement, it is estimated that the closest GAB spring to be 200 km South East of the tenement.

Bridgeport Inland Oilfield in SWQ is located within the Cooper GAB basin, groundwater extraction associated with oil production is carried out at great depths and does not compete with groundwater extraction for domestic, agricultural or other stakeholder uses. The risk to groundwater bores is considered to be negligible considering their distance and the depth at which Bridgeport Energy operates its wells.

The predicted impacts on the GAB aquifers are limited to the close proximity of the oil production wells and the impacts based on current and historical evidence pose a very low risk to the integrity of the GAB. As noted previously the oil water ratio raises as the wells age and as can be seen from tables and bubble maps above our forecast water content by well is likely to rise during 2016. Nevertheless Bridgeport Energy has implemented best well-construction practices to even further reduce any likelihood of any groundwater impacts occurring.

A water monitoring strategy has been developed which goes beyond the requirements of the PL 98 Environmental Approval and demonstrates the Bridgeport activities pose a minimal risk to surrounding ecology or cattle growing activities. This 2015-18 UWIR should be read in conjunction with and supplements our 2012 UWIR (and 2014-15 updates) and demonstrates Bridgeport due diligence with water management in all its operations on PL 98.

Therefore Bridgeport Energy's operation in the Inland Oilfield are not expected to have any material impact on GAB discharge springs or any other GDEs.

APPENDIX A – 2012 UWIR INLAND

UNDERGROUND WATER IMPACT REPORT

INLAND OIL FIELD (PL 98)

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August 2012
Revision 5

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1 Executive Summary

In 2011, the Department of Environment and Resource Management (DERM) introduced a requirement that operators of petroleum production report on the impact that their production of subsurface fluids has on the water in underground aquifers. This report is submitted in accordance with the *Water Act 2000* (Water Act) and it shows that petroleum operations at the Inland Oilfield in Petroleum Lease 98 (PL 98) have had negligible impact on underground water in the region. This applies to both the reservoir unit from which production has been extracted and to the shallower aquifers that landholders might use boreholes from which to extract water.

2 Introduction

2.1 Purpose

The following is the initial Underground Water Impact Report (UWIR) for Bridgeport Energy Limited, and its subsidiary Bridgeport (Eromanga), for PL 98.

This report contains water production information from previous years' production as well as a forecast of water production for the next three (2012-2014, inclusive).

This report complies with Section 376 of the Water Act 2000.

In relation to the Management Units outlined in the *Hydrogeological Framework Report for the Great Artesian Basin Water Resource Plan Area* (Qld DNRM, 2005), the Strategic Management Zone is 1 (Central, Figure 1). The GAB WRP Management zone is 16 (Central, Figure 2) and the units relevant to this report are Central 3, Central 4,and Central 5 (Figure 3).

> "The majority of the groundwater development is situated close to the margins of the area due to the depth to the aquifers and limited population in the central and south western parts. Many of the existing water bores are actually converted petroleum exploration bores. Due to the size of this management area, the hydrogeological properties of each management unit can be quite variable over the area – properties such as pressure, yield, depth, thickness and water quality. Management principles and allocation policies will need to consider this. Setting an allowable drawdown of around two m would allow access reasonable volumes of water from the three main formations." (Qld DNRM 2005, p118)

2.2 Current status

The Inland Oilfield is located in PL 98 (Figure 4). The permit is approximately 40 km^2 in area. The field is in the northern Eromanga Basin approximately 240 kms NW of the Jackson Oilfield and the nearest town is Windorah 120 km to the east. The Inland feature is a fault controlled structure on the flanks of the Morney Dome, one of the major structural features in the north of the Basin. The geological section is a standard Eromanga sequence overlying a thin undifferentiated Triassic package of sediments.

Field development to date consists of 16 wells on the Inland field and one well outside and on trend with the field (Figure 5). A total of 15 completed wells were drilled between 1995 and 2006. Bridgeport acquired this asset from IOR Limited in April 2011. Current production is from a total of 6 wells located within a radius of three kilometres of the plant. The field produces from principally the Hutton Sandstone and to a much lesser extent from the lowest sand in the Birkhead Formation. Oil production occurs between the depth of 1300 and 1500 meters subsea. Current production rates for the field average 160 barrels (0.03 ML) of oil per day and 2200 barrels (0.35 ML) of water per day. A history of the wells can be found in Appendix 1.

3 Part A: Underground water extractions

3.1 Quantity of water already produced

Bridgeport Energy currently produces oil from the Hutton Sandstone and the lower sand of the Birkhead Formation. While the field was brought on line in September 1994, associated water production did not start until July 1995. To date, approximately 2019.5 mega litres (ML) of associated water has been produced (see Figure 6) and a well-by-well summary of cumulative production is shown in Figure 19. The reporting of the total amount of water produced complies with the requirement in S376(a)(i) of the *Water Act 2000* (Water Act).

The majority of all oil and water production comes from the Hutton Sandstone with only minor water production from the Birkhead. Based on drilling and production data it is not possible to determine with certainty the degree of communication between the Birkhead and the Hutton sandstones as the production is comingled (described in Figure 20). Well data in the field suggests that permeability boundaries provide an element of separation between known oil pools. Based on past records and current daily production rates; since 2006 when Inland-4 was converted to a Birkhead producer, the well has produced approximately 1.86 ML of water.

The estimated associated water production is based on records from IOR Limited for the period September 1995 to April 2011. After April 2011, Bridgeport Energy measure oil and water production from each well by means of a test tank and dipstick. The tables in Appendix 2 are a year by year summary of water produced in the Inland Oilfield.

3.2 Quantity of water to be produced in the next three years

The current average water production from each well is approximately 2200 barrels per day. Based on Bridgeport Energy's Later Development Plan, Bridgeport proposes to drill four new Hutton reservoir wells in the next three years. Using the average production rates, the additional associated water production from primarily the Hutton Sandstone (Central 5) is forecasted (as per S376(a)(ii)), in the table below:

Wells Drilled	Dates Online	Incremental production @ end Dec-14 (ML)	Forecast production from existing wells (ML)	Total Forecast Water Production (ML)
1	Oct-12	10.7	383.0	393.7
2	Jul-13	17.6	383.0	400.6
3	Apr-14	21.1	383.0	404.1
4	Dec-14	21.3	383.0	404.3

To calculate these figures, the water cut was plotted against time using production data from three of the most recent Inland wells to form a forecast water-cut profile for new Hutton Sandstone wells in the field. This line of best fit was combined with Bridgeport's forecast of oil production rate from the Hutton for new wells. From this combination, forecast water rates for new Hutton wells were created and presented in Figure 7.

As Bridgeport develops the Birkhead oil reservoir, both water and oil production will be recorded and reported on in future reviews. However, it will remain uncertain if all the water is coming from the Birkhead due to the potential for natural communication between the Hutton and Birkhead reservoirs/aquifers.

3.3 Currently Producing Zones

Bridgeport currently produces from the Inland Oilfield in SMP Zone 1, GAB WRP Zone 16 which is approximately 214,000 km^2 in area (Figures 1 & 2). Central 4 and Central 5 are currently produced with only minor production in the past from Central 3. Water produced is associated water from oil production. Bridgeport does not use this water for water flooding activities and, at the time of this report, has no plans to do so. However, there may be future beneficial advantage to consider water flooding (injection) in this reservoir to minimise the output of water under existing discharge rights in the Environmental Authority.

4 Part B: Aquifer information and underground water flow

To comply with S376(b), the primary aquifer affected by water extraction is Central 5 (Hutton Sandstone). Units in Central 3 (McKinlay/Namur) and 4 (Birkhead) are considered secondary contributes to total water production with Central 3 was sporadically produced from 2002-2008 under the previous operator. Other units are not considered likely to be affected as they are behind casing and not in communication with the petroleum producing intervals.

4.1 Description of each aquifer

4.1.1 McKinlay Member and Namur Sandstone (Central 3 – not producing)

The formations in Central 3 are described in the *Hydrogeological Framework Report for the Great Artesian Basin Water Resource Plan Area* 2005 as follows:

> "The Hooray sandstone and its hydrogeological equivalents are generally the shallowest major artesian aquifer intercepted by water bores in the GAB in Queensland. The Late Jurassic Hooray Sandstone aquifer is defined only within the Eromanga Basin." (p15).
>
> "Basin margin facies of the Jurassic and early Cretaceous sandstones and siltstones occur in…the Eromanga (Namur Sandstone, McKinlay member and Murata Formation). These basin margin facies are hydrogeologically equivalent to the Hooray sandstone aquifer." (p15).

The detailed description from the wells follows as per the requirement in S376(b)(i). The Murta Member is a very fine to fine grained sandstone with interbedded hard siltstone. The sandstone is subangular to subrounded, moderate to well sorted with a moderate to abundant clay matrix. Moderate amounts of silica cement are present and it is moderately hard with poor porosity. The Central 3 unit ranges in thickness from approximately 120-130 m.

The McKinlay Member is a fine to medium grained siltstone with minor firm siltstone. The sandstone is subangular to subrounded, moderately sorted with occasionally carbonaceous laminae. There is a moderate clay matrix that is slightly calcareous and moderate silica cement. The formation is moderately hard with poor to occasionally fair porosity.

The Namur Member is sandstone with interbedded siltstone. The sandstone varies from very fine to coarse. It's moderately sorted with clay matrix and moderate silica and calcareous cement and ranges from friable to moderately hard. Poor to fair with occasional good porosity has been observed. This siltstone is argillaceous with firm with moderately to abundant carbonaceous material.

4.1.1.1 Elevations and relative position

The McKinlay Member and Namur Sandstone are Late Jurassic to Early Cretaceous sediments (Figure 8). The depth ranges across the lease from 1071 to 1120 mSS. Within the Inland Oilfield the range is 1071 to 1097 mSS. The Namur formation ranges in top depth across the lease from 1088 to 1149 mSS and within the Inland Oilfield, the range is -1088 to -1111 mSS (Figure 9). The wells that have tested or perforated the formations in Central 3 are shown in Figure 10.

4.1.1.2 Location of water bores screened within these aquifers

There is one shut-in oil well in the Inland Oilfield which has been classified in the DERM/DEHP database as water bore 100199. This well was shut-in in June 2002 and abandoned in September 2002. This well drilled to a total depth of 1865m in the Nappamerri Formation. It has in the past produced from the Hutton Sandstone (Central 5) and the Namur Sandstone Member (Central 3). The well history is outlined in Appendix 1.

The next closest shut-in oil well that appears in the DERM database is water bore 23099 (Morney 1). This well is approximately 11 km to the north. The well was plugged back to 230 m, so it would not be accessing these zones. The closest converted oil well is water bore number 22946 (Curalle-1) which is over 50 km to the southwest from the Inland Oilfield, which is considered to be too far to detect changes in any of the aquifers.

In general, "...the majority of bores occur in the northern, western and southeastern boundaries where the formation is at shallower depth....[as] due to the considerable expense to drill to such depth..." as is found in the central region where PL 98 is situated. (Qld DRNM 2005, p118).

4.1.1.3 **Location of any significant faults that intersect aquifer**

The Inland Oilfield is bounded on the northwest flank by a major thrust fault, approximately 330 m from Inland-1. Inland-5 is the only well to have perforated the McKinlay. Inland Northeast-1 tested the Murta/McKinlay, but was never completed over this interval. The well is approximately 640 m from the main fault. A number of minor crestal faults may provide a degree of compartmentalization of the Central 3 units (Figure 11).

4.1.1.4 **Available data on current underground water levels**

The McKinlay was perforated in February 2003 in Inland-5. At this time the field was managed by the previous operator IOR Exploration. The records that were supplied to Bridgeport indicate that from February 2003 to August 2008, the McKinlay produced a total of 1,987 barrels/0.32 ML of water.

The Namur was perforated in Inland-1 at completion of the well in 1994. Namur production was comingled with the Hutton Sandstone (production of fluid from two or more separate zones through a single pipe and where production from individual zones can not be measured). In March 2002, the Namur was isolated behind a packer and production was solely from the Hutton.

Inland-3 perforated the Namur and as it flowed only water, the formation was shut-in immediately and no further production occurred.

Inland-9 tested the Namur and recovered oil-cut muddy water and water. The zone was not completed after casing was run and no further water production occurred.

The oil/water contact, and therefore the water level, for these reservoirs is not clear as the reservoirs have not undergone significant oil filled development. It appears that the lowest known oil is the base of the perforation in Inland-5, which is 1255.8 mMD/1090.8 mSS. As all tests recovered some oil, the free water level is not known.

Given that very little fluid production has come from this reservoir and that the overall extent of Central 3 is enormous, it is concluded that the aquifer water levels, referred to in S376 (b)(iv), will remain unchanged in the area of the lease.

4.1.2 **Birkhead Formation (Central 4 – currently producing)**

The formations in Central 3 are described in the *Hydrogeological Framework Report for the Great Artesian Basin Water Resource Plan Area* 2005 as follows:

> "Birkhead Formation comprises siltstone, fine sandstone, mudstone and minor coal. It obtains a maximum thickness of 130m and is absent in the west and south of the Eromanga Basin over the Thargomindah and Cunnamulla shelves (Senior et al, 1978), and west of the Nebine Ridge. The sandstones are generally clayey and the formation acts primarily as a confining bed, providing only small supplies of poor quality water". (p13).

The detailed description from the wells follows as per the requirement in S376(b)(i). The Birkhead Formation is interbedded sandstone and siltstone. The sandstone is very fin to fine grained, subangular to sub-rounded, moderate to well sorted. There is moderate to abundant clay matrix and friable to moderately hard. There is carbonaceous material, feldspars and lithic throughout with poor to fair porosity observed. The siltstone is firm and carbonaceous, occasionally sandy in part. In PL 98, the thickness of the Central 4 unit is approximately 90-100m.

4.1.2.1 **Elevations and relative position**

The top of the Jurassic Birkhead Formation, see Figure 8 for stratigraphic position, ranges in depth across the lease from 1317 to 1379 mSS. The depth range within the Inland Oilfield is 1317 to 1345 mSS. The primary section that is produced ranges in top depth of 1396 to 1425 mSS (Figure 12). Figure 13 shows the wells that have tested or perforated the Birkhead Formation in Management Unit Central 4.

4.1.2.2 **Location of water bores screened within these aquifers**

There is one shut-in oil well in the Inland Oilfield which has been classified in the DERM database as water bore 100199. This well was shut-in in June 2002 and abandoned in September 2002. This well drilled to a total depth of 1865 m in the Nappamerri Formation. It has in the past produced from the Hutton Sandstone (Central 5) and the Namur Sandstone Member (Central 3). The well history is outlined in Appendix 1.

4.1.2.3 **Location of any significant faults that intersect aquifer**

The Inland Oilfield is bounded on the northwest flank by a major thrust fault, approximately 500 m from Inland-2, 200 m from both Inland-4 and Inland-7, 170 m from Inland-5, and 590 m from Inland-11 (Figure 14). A number of minor crestal faults may provide a degree of provide a degree of compartmentalisation for the Birkhead sand units (Figure 14). The Inland Oilfield is contains a number of smaller faults that may compartmentalize the field. The major fault is approximately 500 m from Inland-2.

The next closest shut-in oil well that appears in the DERM database is water bore 23099 (Morney-1). This well is approximately 11 km to the north. The well was plugged back to 230 m, so it would not be accessing these zones. The closest converted oil well is water bore number 22946 (Curalle-1) which is over 50 km to the southwest from the Inland Oilfield , which is considered to be too far to detect changes in any of the aquifers.

4.1.2.4 **Available data on current underground water levels**

> "There is only limited extraction from the Injune Creek Group and Hutton Sandstone. Both units extend beneath the majority of the management unit, excluding the northwest and southeast corners. However, the depth to these units precludes most drilling due to the expense and the existing bores are generally converted oil bores." (Qld. DNRM 2005, p118)

The Birkhead Formation first produced oil in November 1996 from Inland-5, which was comingled with oil from the Hutton Sandstone until 2002. At that time, a bridge plug was set, isolating the Hutton from production. The Birkhead Formation continued to produce until February 2003, when another bridge plug was set above the Birkhead. It continued to produce from the McKinlay until 2006 when it was shut-in.

A Birkhead sand in Inland-7 was perforated upon completion of the well in February 1997. Inland-7 has since produced comingled with the Hutton Sandstone.

Inland-11 perforated the Birkhead, comingled with the Hutton, in 2001 upon completion and remains producing to date.

When the Hutton Sandstone water out in June 2006, the lower Birkhead sand was perforate din both Inland-2 and Inland-4 immediately after a bridge plug. Inland-2 was then shut-in November 2006. In August 2008, both Inland 2 and 4 were fracced in the lower Birkhead sand. Inland-4 predominantly oil (~5 barrels/~0.001 ML of water per day) whereas Inland-2 was shut-in when it watered out December 2008. As at the end of 2011, 23,600 barrels/3.75 ML of oil and 8,315 barrels/1.32 ML of water have been produced from sands within the Birkhead Formation. The majority of the fluids produced from the Birkhead are from Inland 4. This is the only well to be solely completed over the Birkhead and is currently producing at 25 bopd/0.003 MLopd with less than 5 bwpd/0.001 MLwpd. Other wells that have perforations in the Birkhead only produce very minor amounts of oil and water although it is not possible to determine this with any precision as the flow from the wells with dual zone perforations is co-mingled.

The upper-most water level in the lower Birkhead oil reservoir is estimated to be between 1419 mSS and 1428 mSS. This depth range is interpreted from the upper-most perforation at Inland-5 and the lowest known perforation in Inland-7. Based on the continual production of water and oil from the Birkhead formation, the water in the reservoir shows no sign as pressure depletion from the production of oil and associated water.

Given the large volume and good connectivity of the Birkhead aquifer system in the vicinity of PL 98, it is expected that as Birkhead oil is produced, formation wast will enter the trap and therefore the water level will rise. Hence, no aquifer depletion as referred to in S376 (b)(iv) is expected.

4.1.3 **Hutton Sandstone (Central 5 – currently producing)**

The formations in Central 3 are described in the *Hydrogeological Framework Report for the Great Artesian Basin Water Resource Plan Area* 2005 as follows as S376(b)(i):

> “The Hutton Sandstone is comprised of fine to coarse grained quartzose sandstone, lithic sandstone, siltstone and mudstone deposited from rivers and lakes (Senior et al, 1978; Radke et al, 2000). In the outcrop areas the sandstone is often partly silicified and ferruginised or with kaolinitic clay infilling pores (Kellett et al, 2003). The lower part of the Hutton Sandstone is generally finer grained, containing more mudstone and siltstone than the upper part, which is a much more uniform sandstone (Green, 1997).
>
> In the northern part of the Eromanga Basin, this unit was the beginning of the sedimentary sequence and sits unconformably on the basement of the Galilee basin sediments ((Senior et al, 1978; Kellett et al, 2003). The Hutton Sandstone attains maximum thickness of approximately 250 m in the central Eromanga Basin and the Taroom Trough. This unit is absent over elevated basement in the north and northwest and thins towards the southern margin of the Cooper Basin.
>
> The Hutton Sandstone contains good to excellent aquifers with yields up to 50 L/s of good quality water. Recharge areas are on the eastern margins Eromanga Basin and other and eastern margins of the Surat Basin (Habermehl, 1980; Exon, 1976).” (Qld DNRM, 2005, p11).

4.1.3.1 **Elevations and relative position**

The Early to Mid Jurassic Hutton Sandstone, see Figure 8 for stratigraphic position, ranges in top depth across the permit from 1411 to 1471 mSS. Within in the Inland Oilfield the range is 1411 to 1447 mSS.

4.1.3.2 **Location of water bores screened within these aquifers.**

As per S376(d) Bridgeport has identified one shut-in oil well in the Inland Oilfield which has been classified in the DERM database as water bore 100199 (Figure 23). This well was shut-in in June 2002 and abandoned in September 2002. This well drilled to a total depth of 1865 m in the Nappamerri Formation. It has in the past produced from the Hutton Sandstone (Central 5) and the Namur Sandstone Member (Central 3). The well history is outlined in Appendix 1.

The next closest shut-in oil well that appears in the DERM database is water bore 100226 (Morney-1), which is in another petroleum company’s tenure. This well is approximately 11 km to the north. The well was plugged back to 230 m, so it would not be accessing these zones. The closest converted oil well is water bore number 22946 (Curalle-1) which is over 50 km to the southwest from the Inland Oilfield (beyond extent of Figure 23), which is considered to be too far to detect changes in any of the aquifers.

> "There is only limited extraction from the Injune Creek Group and Hutton Sandstone. Both units extend beneath the majority of the management unit, excluding the northwest and southeast corners. However, the depth to these units precludes most drilling due to the expense and the existing bores are generally converted oil bores" (Qld DNRM 2005, p118).

4.1.3.3 **Location of any significant faults that intersect aquifer**

The Inland Oilfield contains a number of smaller faults that may compartmentalize the field. The major fault is closest to Inland-6, 103 m away, and is furthest from Inland-10 at a distance of 657 m.

4.1.3.4 **Available data on current underground water levels**

All wells in the Inland Oilfield were completed in the Hutton. Beal-1, which is the northeast of the permit, and Inland-6/6A were plugged and abandoned with no production from any reservoir. Inland-14 was completed, but no production has ever taken place form this well. The full history of which wells have produced and which have been shut in over the interval after a time is outlined in Appendix 1.

The current oil/water contact, and therefore the water level is estimated to be approximately 1488 mSS. The reservoir/aquifer shows no signs of pressure depletion due to oil production. Over time, the water level naturally rises as the oil is produced out of the trap. And because there is a substantial volume of water in the Hutton Sandstone that has access to the Inland Oilfield, no water depletion is expected. On a regional aquifer scale, the impact of fluid production on the Hutton Sandstone is expected to be minimal. The schematic in Figure 21 shows oil floating on water because it is less dense. The Figure also shows that the zone that oil is produced from occupies a relatively small volume of the Hutton Sandstone. However, it cannot be accurately determined as the Inland Field occupies a small part of the basin aquifer and it is isolated from other producing oil fields in the Cooper Basin (Figure 4). Within PL 98, water coning of 2-5 m as a result of well bore drawdown occurs in the near well bore environment, which is a normal part of oil production that equalises after the well is shut in.

4.2 Underground water flow and aquifer interactions

Bridgeport acquired this asset from IOR Limited in April 2011. At the time of this report, Bridgeport is continuing to interpret the data provided by IOR in order to develop an understanding of the relationship and interaction between petroleum reservoirs and water aquifers. Bridgeport has identified faulting on the flanks and crest of the Inland structure and some communication between reservoirs may naturally occur as evidenced by the occurrence of oil in a number of stratigraphic levels. However, the affected strata lie within a depth range of 1000 m and 1500 m.

"Water quality in all the units is generally more saline than experienced closer to the Basin margins. The residence time in the aquifer and the influence of water from the underlying Cooper Basin has reduced water quality" (Qld DRNM 2005, p118).

4.2.1 **McKinlay Member and Namur Sandstone (Central 3)**

> The Hooray Sandstone extends over the whole management area, however the majority of bores occur in the northern, western and southeastern boundaries where the formation occurs at shallower depths. However, these depths can still be nearly 1000 m and many of the bores are ex-oil bores due to the considerable expense to drill to such depths. The unit provides water of varying quality with high heads and yields of up to 60L/s, averaging around 15L/s. The water supplies for Thargomindah Township come from this unit. (Qld DNRM 2005, p118).
>
> "In the Central Eromanga Depocentre (Cooper Basin Region) the combined Namur Sandstone, McKinlay member and Murta Formation are laterally

> continuous with the Hooray Sandstone. These formations are restricted to subsurface and are recharged from connecting Hooray Sandstone in the east and Algebuckina Sandstone in the west. Confined aquifers are found in all three members, which are connected." (Qld DNRM 2005, p17).

The McKinlay Formation was tested in Inland-5 and Inland NE-1. In Inland-5, the test covered primarily the Murta Formation and only the upper-most of the McKinlay was included. In Inland NE-1, the test interval was primarily in the McKinlay and only the base Murta was included. This test recovered oil, watery mud and mud and no water sample was available for testing.

The Murta Member provides a top seal for the McKinlay and Namur reservoirs. The Murta is predominantly siltstone with a few fine to very fine grained sand stringers. Above the Murta is the base Cadna-owie Formation, which is a regional seal unit in the Copper-Eromanga Basin.

"These formations are restricted to subsurface and are recharged from connecting Hooray Sandstone in the east and the Algebuckina Sandstone to the west. Confined aquifers are found in all three members, which are connected." (Qld DRNM 2005, p17). However, there are there are intra formational seals interpreted form log character with the Central 3 reservoirs within the Inland Oilfield.

The Westbourne Formation lies between the Namur and Adori sandstone and it has a very thick sealing silting at its top. This provides a base seal for the Namur and McKinlay sandstones ensuring no communication with deeper reservoirs.

The table below presents the some of the key properties of the water analyses for the various well's recoveries from the Namur Member. The full chemical analyses for these samples are in Appendix 3. Note these are samples that have been produced in a drill stem test and have interacted with oil and drilling fluid. These are therefore not representative of true groundwater chemistry drill stem test recoveries are contaminated by drilling muds.

Well	Ph	Resistivity @25C (ohm.m)	Conductivity @25C (μS/cm)	Total Cations (meq/L)	Total Anions (meq/L)	Total Dissolved Solids (mg/L)
Inland-1	7.8	0.22	45,700	464.50	466.80	29,248
Inland-9	7.1	0.92	10,860	125.73	118.85	6,950

4.2.2 **Birkhead Formation (Central 4)**

There are no water analyses on the Birkhead Formation in PL 98.
"The sandstones are generally clayey and the formation acts primarily as a confining bed, providing only small supplies of poor quality water" (Qld DRNM 2005, p13).

The Birkhead is a relatively poor quality reservoir. The formation is generally of low porosity and permeability, so the contribution to the total oil and water production of the field to date is minimal. The majority of all oil and water production comes from the Hutton Sandstone with only minor water production from the Birkhead. Based on drilling and production data it is not possible to determine with certainty the degree of communication between the Birkhead and the Hutton sandstones. Well data in the field suggests that reservoir seals provide an element of separation between known oil reservoirs. Given that underlying Hutton reservoir was drained of oil in the Inland-4 area, the low level of water production from the Lower Birkhead reservoir in that well suggests that there is a high degree of isolation of the Birkhead and Hutton oil pools in this area.

4.2.3 **Hutton Sandstone (Central 5)**

There is only limited extraction from the Injune Creek Group and Hutton Sandstone. Both units extend beneath the majority of the management unit, excluding the northwest and southeast corners. However, the depth to these units precludes most drilling due to the expense and the existing bores are generally converted oil bores. (Qld DRNM 2005, p118)

The table below presents the water analyses for the various well's recoveries from the Hutton Sandstone. The full chemical analysis for these samples are in Appendix 4. Note that fluid samples taken during drill stem tests are often comprised of oil, drilling fluid and formation water. These are therefore not representative of true groundwater chemistry drill stem test recoveries are contaminated by drilling muds.

Well	Ph	Resistivity @25C (ohm.m)	Conductivity @25C (μS/cm)	Total Cations (meq/L)	Total Anions (meq/L)	Total Dissolved Solids (mg/L)
Inland-1	7.1	0.18	55600	475.8	470.7	35584
Inland-2	4.7	0.28	36200	372.0	363.3	23168
Inland-3	6.6	1.72	5800	77	77.2	3712
Inland NE-1	7	1.64	6110	63.03	66.78	3910

4.3 Underground water level trend analysis

It is not possible to generate maps of these depth of aquifers as no regional closure is possible to identify given they are present throughout the Eromanga Basin which "is the largest of the main [Great Artesian Basins] and extends across Queensland, New South Wales, South Australia and the Northern Territory (650 000km2 in area in Queensland)" (Qld DNRM 2005, p4). Depths of the aquifers preclude verifying regional extent. Bridgeport will continue to research literature and as field development continues, more information regarding the rise in the water table will be collected.

What is known about the aquifers so far has been acquired through the drilling of development wells in the field. The majority of all production comes from this Hutton Sandstone. It is not possible to determine if there is communication between the Birkhead and the Hutton Sandstone (Figure 20). Well data in the field suggests that reservoir seals provide an element of separation between known oil reservoirs. Based on drilling and production data it's not possible to quantify the degree of communication between the reservoirs.

5 Part C: Predicted water level declines for the affected aquifers

5.1 Maps of the affected area

The Inland Oilfield covers an area of approximately 3.5 km^2 in PL 98, which is 40 km^2 (Figure 18). The structure of the Inland Field has been mapped from the interpretation of 3D seismic data. The free water level has been determined through petrophysical studies of the wells from wire line logs and from water encroaching into wellbore perforations.

The field produces primarily from the Hutton Sandstone with minor contributions from the lower Birkhead Formation. To date, approximately 604 ML of oil and 12.7 MM barrels/2019.14 ML of water have been produced from the Inland Oilfield. No decline in water levels has been observed as is the concern of S376(b)(iii); and in fact, there is evidence that the water table within the bounds of the field has risen. As oil was produced, down dip formation water within the massive Hutton Sandstone moved into the structure, replacing the oil and resulting in a rise in the oil/water contact of between 20 and 26 m.

5.2 Methods and techniques used

The map in Figure 18 shows a notional area of water recharge for oil produced (S376 (iv and v)). The notional area of influence, based on the ellipse (23 km by 14 km) shown in Figure 18, is 264 km^2. The notional area was defined in the northwest by the regional field bounding thrust fault, and then extended downdip in all directions by approximately 12 km. The reasoning here is that the Hutton Sandstone is a relatively homogeneous unit with good reservoir properties that results in good communication of fluids within the reservoir. This area is down dip of the oilfield and it corresponds to the immediate region of aquifer support for the Inland Oilfield. Applying the following Hutton reservoir parameters to this area results in a gross rock volume of 61 trillion cubic metres and a net reservoir volume of 3.8 trillion cubic metres.

Area (km^2)	Thickness (m)	Geometric Factor	Net/Gross	Porosity (%)	Recovery (%)
264	230	0.75	0.9	11.6	0.8

The aquifer volume in the immediate area of the Inland Oilfield is significant. The Hutton Sandstone is more than 130 m thick and the total pore volume solely within the Petroleum Lease (40 km^2) is approximately 600,000 ML. Clearly this aquifer volume dwarfs the amount of water (2020 ML) and oil (600 ML) produced from the reservoir to date.

The notional area of affected aquifer relates to the Hutton reservoir (Central 5) with less than $1/200^{th}$ of total current water production coming from the Birkhead (Central 4) and other secondary reservoirs (McKinlay & Namur – Central 3). Figure 22 has been added to graphically show how much water has been produced from each well, bearing in mind that only a small amount of water (less than 3 ML) has been produced from the secondary reservoirs.

There is no evidence of water decline in any of the Inland wells, nor is there any decline anticipated elsewhere in the area of the field as a result of the Inland oil production. The Hutton Sandstone is a very large aquifer that contains good to excellent quality sands that allow liquids to readily move updip to displace any produced oil. This situation is common in the case of oil fields with good aquifer support, which was verified by reservoir simulation work in 2006.

The Hutton Sandstone is regionally extensive in the Eromanga basin which “is the largest of the main [Great Artesian Basins] and extends across Queensland, New South Wales, South Australia and the Northern Territory (650 000 km2 in area in Queensland)” (Qld DNRM 2005, p4).

5.3 Water bores within the Immediately Affected Area

As per S376(d) Bridgeport has identified one shut-in oil well in the Inland Oilfield which has been classified in the DERM database as water bore 100199 (Figure 23). This well (Inland-1) was shut-in in June 2002 and abandoned in September 2002. The well was drilled to a total depth of 1865 m and reached total depth in the Nappamerri Formation. It has in the past produced from the Hutton Sandstone (Central 5) and the Namur Sandstone Member (Central 3). The well history is outlined in Appendix 1.

Other water bores in the database provided by DEHP are shown in Figure 23. These bores access the Quaternary sediments, the Winton Formation and the Glendower Formation. None of the bores were screened across units produced in the Inland Oilfield. The table below provides the distances of the surrounding bores from the PL 98 tenure and the Inland Oilfield. On the basis of the distance of these water bores from the field and the fact that these bores do not access the Central 3, 4 or 5 units, there is no means of using these bores or the Inland wells to infer any sort of aquifer interactions or impact on effective pressure.

Bore	Formation	Distance from PL 98 (km)	Distance From Inland Oilfield (km)	Comment
4396	-	7.4	14	
7740	Quaternary,Glendower,Winton	6.7	13.4	
8047	Quaternary,Glendower,Winton	5.6	6.8	
12552	Quaternary,Glendower	18.6	20	
12593	Quaternary,Glendower	10.9	11.7	
13021	Quaternary,Glendower,Winton	6.7	13.4	
13114	Quaternary,Glendower,Winton	13.3	15.3	
13544	Quaternary,Glendower	9.8	11.3	
13743	Quaternary,Glendower	7	8.5	
14209	Quaternary,Glendower,Winton	16	17	
16489	Quaternary,Glendower,Winton	7.4	8.6	
23695	-	14.5	16.1	CUDDAPAN-1: plugged back to surface, next plug at 344 m
36307	Quaternary,Glendower	13.1	15.8	
51804	Quaternary,Glendower	15	16.1	
69179	-	3.3	8.2	
69562	Glendower	3.6	10.3	
93025	-	8.6	9.5	
93999	-	8.2	9.7	
100199	-	in permit	in field	INLAND-1: shut in oil well
100226	Winton	9.6	12	MORNEY-1: Plugged back to 230 m
118000	-	11.6	13.8	
118622	-	12.8	17.7	

5.4 Review of maps produced

As this is the first UWIR produced, there are therefore no maps to review as stipulated by S376(e)(i).

For future years, Bridgeport will conduct annual reviews in January to report production from the wells as per S376(e)(i). These reviews will note any significant increases or decreases in volumes and comment as to why they occurred (i.e. additional wells) and what the expected effect on the aquifer will be (ie, changes in local water levels/oil water contacts).

From these reviews, cross sections and maps will be generated to demonstrate what the changes represent and will be summarized and reported to DEHP as perS376(e)(ii) and discuss with local land owner(s) as part of our normal practice of public disclosure. These reviews will be incorporated and elaborated on in the relevant section in future UWIR's.

6 Part D: Water Monitoring strategy

6.1 Rationale

The purpose of this document is to provide the details of how Bridgeport Energy currently conducts water monitoring operations as per S376(f) and more detailed in S378. Further to this, it also explains how the information acquired from these operations is applied to assess changes in aquifer properties, particularly water levels and water quality.

6.1.1 Assessment of changes in water levels and water quality because of relevant underground water rights

Due to the massive regional extent of these aquifers there is excellent pressure support during the entire period that oilfield production has occurred. A drop in water levels has not been observed, and indeed, a rise in the water/oil contact has been seen during production operations. Water level is monitored through producing oil wells. When a producing well reaches an uneconomical percentage of water cut, it is because the water level has risen locally around the well. Future infill wells are located to optimise oil production and minimize the percentage of water produced.

The absence of producing water bores in the area of PL 98 means that there is no feasible way to assess changes in water levels, although Bridgeport Energy does measure water quality in the evaporation ponds routinely as per DERM operating conditions for the permit.

6.1.2 Supplementation of existing monitoring programs to fill any critical gaps in data

At the present time, it is the position of Bridgeport Energy that the monitoring programs currently being employed are adequate to collect the data required to effectively monitor the relevant underground water properties and that there are no critical gaps in data. Consequently, it has not been deemed necessary to conduct any such supplementation of Bridgeport's existing monitoring programs as suggested in S378 (3) as the nearest water bore is over 50 km to the southwest from the Inland Oilfield, which is considered to be too far to detect changes in any of the reservoirs/aquifers.

6.1.3 Explanation about how it will improve the understanding about the impacts of underground water extractions on aquifers

The monitoring strategy currently being employed by Bridgeport Energy includes that acquisition of data relating to the volumes of water extracted from the reservoir. That is, the strategy allows Bridgeport to understand rates of water extraction over time but does not measure changes in the aquifer's water level over time because the regional aquifer is so large (extending well beyond the lease boundary). As noted in Part C, the regional aquifer is more than 1,300 times larger than the volume of the oilfield.

In addition to the subsurface aquifer water levels, large amounts of data are acquired pertaining to water quality. This data acquisition is undertaken on a quarterly basis and as such, the water quality can be assessed at various stages throughout the production life. Having the water quality analysed at these different stages, will facilitate historical comparisons of water quality and underground water extraction. These comparisons will significantly enrich the levels of understanding of the impacts of underground water extraction on aquifer water quality and if any impact does exist, this process will ensure that it can be easily identified.

6.2 Monitoring Strategy

Bridgeport Energy's monitoring strategy is based on three primary parameters. These are formation water production history, reservoir oil/water level depth and water quality. By closely monitoring and keeping good records of these parameters, Bridgeport Energy has developed a monitoring strategy that meets the requirements of Section 376(f) of the Water Act. The following section provides more specific details of how these parameters are collected.

6.2.1 **Formation Water Production History**

In order to effectively evaluate the impact of water extraction on the aquifer, it is vital to know the volume of water that has been extracted. As such, Bridgeport Energy has implemented a water production monitoring system that allows the volume of water that has been produced from the reservoir to be calculated. The following is a summary of this system.

- Within the field, each well is flow tested into an isolated test tank. After a settlement period, the contents of the tank are volumetrically measured by means of a dip-stick and water-indicating paste. Volumes of both produced oil and water are obtained from this measurement as per S378(a).

- With the volumes and the time period known, a daily production rate for oil and water is calculated as per S378(c).

- Daily water rates from all wells are then cross-referenced with daily uptime data and from this, the quantity of water produced by a given well in a given day can be calculated. The lcoations of these wells are presented in the table in section 6.3 of this report as required by S378(b).

As a result of this process, historical water production statistics are available for the field and on a per-well basis. Consequently, Bridgeport Energy has a thorough understanding of the quantity of water that has been extracted as well as extraction rates throughout the field's history.

6.2.2 **Underground water level depth**

The second parameter that Bridgeport monitors is the depth of the underground water level. Since a significant portion of the requirements under S376(f) of the Water Act pertain directly to the relationship between water extraction and underground water level depth, this parameter is also essential. Bridgeport has adopted two chief methods of evaluating this.

The first of these is through analysis of current wells and their production status. As has been described above, the general trend for the underground water level is that it rises as oil is depleted. Consequently, when an existing well waters out (ceases to produce oil and only produces water), it can be inferred that in the immediate localised area, the underground water level depth has risen to the depth of the well's perforations.

The second of these is through identification of the oil/water contact in new wells as they are drilled. When new wells are drilled, the oil-water contact at the time of drilling can be identified by log analysis. Since the depth of the oil/water contact is defined as the top of the aquifer water level, identification of the oil/water contact through log analysis also allows aquifer water level depths to be understood.

As with the water production history, maintaining good records of these parameters as they become available has resulted in a firm understanding of the original reservoir water level depth as well as how this depth might change over the production life of the Inland Oilfield as water displaces oil.

6.2.3 **Water quality**

The final parameter that comprises Bridgeport's monitoring strategy is that of water quality. In accordance with the Environmental Authority associated with PL 98, Bridgeport Energy performs routine analyses of its produced water. This water is taken from the evaporation ponds and is sent to a professional chemical analysis organisation where it is analysed for a wide range of contaminants. With the results of these analyses, Bridgeport is able to consistently monitor the quality of its produced water and combined with the water production history, can also analyse changes in water quality for relationships with the quantity of water extracted.

6.3 Timetable

All parameters monitored as part of the monitoring strategy are also monitored for reasons of good oil reservoir management practice. Hence, Bridgeport reports water and oil production quarterly to DERM, annual National Pollutant Inventroy (NPI) reporting, and quarterly water testing as is outlined by DERM issued Environmental Authority.

In some cases monitoring is done daily, in other cases monitoring takes place during particular events such as the drilling of a new well. Furthermore, some measurements are applicable to the field as a whole and as such, these measurements are not strictly applicable to any individual well. The following table depicts the monitoring timetable according to which, Bridgeport will be operating.

Well Name	Tenure	Location	Water Production Monitoring	Aquifer Level	Water Quality
Inland-4	PL 98	141 37 49 E 25 32 42 S	Daily	N/A	N/A
Inland-5	PL 98	141 38 18 E 25 32 24 S	Daily	N/A	N/A
Inland-7	PL 98	141 38 38 E 25 32 14 S	Daily	N/A	N/A
Inland-8	PL 98	141 37 58 E 25 32 47 S	Daily	N/A	N/A
Inland-9	PL 98	141 38 30 E 25 32 31 S	Daily	N/A	N/A
Inland-10	PL 98	141 37 42 E 25 33 03 S	Daily	N/A	N/A
Inland-11	PL 98	141 37 30 E 25 33 07 S	Daily	N/A	N/A
Inland-12	PL 98	141 38 41 E 25 32 25 S	Daily	N/A	N/A
Inland-NE1	PL 98	141 39 23 E 25 32 02 S	Daily	N/A	N/A
Field Level Measurements	PL 98		Daily	As new wells are drilled if they intersect the OWC above the current mapped depth/ As an existing well waters out as oil production declines.	Quarterly (From testing of Evaporation Pond Water)

6.4 Reporting Program

For water production monitoring, Bridgeport Energy provides water production statistics to the QDME on a six-monthly basis.

For water quality, Bridgeport Energy provides water samples to the landowner on a quarterly basis in compliance with the Environmental Authority for PL 98.

For aquifer water levels, Bridgeport Energy obtains petrophysical data by reference as new wells are drilled. As the OWC movement is only constrained within the reservoir this form of data is not relevant to water extraction levels (i.e. they do not change substantially over the 20 year life of a well). Further reporting to the Queensland Water Commission (QWC) has never been implemented as these regional aquifers are below any known extraction points for irrigation or domestic use, as detailed above.

7 Part E: Spring impact management strategy

A spring is defined in the *Water Act 2000* Schedule 4 as “the land to which water rises naturally from below the ground and the land over which the water then flows”.

7.1 Spring inventory

There are no springs within PL 98 to report as per s376(g) or s379. This was confirmed with ESRI Shape Files supplied by the Queensland Government Information Service website. From this data, it was confirmed that the nearest spring is 93 km to the NE of the PL 98 tenure.

7.2 Connectivity between the spring and aquifer

N/A

7.3 Spring values

N/A

7.4 Management of impacts

N/A

7.5 Timetable for strategy

N/A

7.6 Reporting program

N/A

8 Part F: For a CMA assign responsibilities to petroleum tenure holders

PL 98 is not part of a CMA as per s376(i).

9 References

Water Act (2000) Reprint 8F effective March 2f012

Queensland Department of Natural Resources and Mine (2005) *Hydrogeological Framework Report for the Great Artesian Basin Water Resources Plan Area,* Version 1.0

Queensland Department of Environment and Resource Management (2012) *Guideline: Underground Water Impact Reports and Final Reports* Energy Resources, Environment and Natural Resource Regulation

Queensland Government Information Service: www.dds.information.qlg.gov.au Queensland Wetland Data – Spring ESRI Shape File

Well Completion Reports:
- Beal-1
- Inland-1
- Inland -2
- Inland-3
- Inland-4
- Inland-5
- Inland-6/6A
- Inland-7
- Inland-8
- Inland-9
- Inland-10
- Inland-11
- Inland-12
- Inland-13
- Inland-14
- Inland-15
- Inland Northeast-1
- Morney-1
- Curalle-1

10 Figures

Figure 1: **Strategic Management Plan Zones**

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Figure 3: **Correlation of the management Units in the Eromanga Basin**

Figure 4: **Tenement Location Map**

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Figure14: **Lower Birkhead (Central 4) Depth structure Map**

Figure 15: **Schematic Cross Section of Central 5**

Figure 16: **Wells that perforated or tested Central 5**

Figure 17: **Hutton (Central 5) Depth Structure Map**

Figure 18: **Notional Area of Aquifer Affected**

Figure 19: **Cumulative Water Production for Individual Inland Wells**

Figure 20: **Comingled Production**

Figure 21: **Petroleum Reservoir and Trap for Inland Oilfield**

Figure 22: **Bubble map showing relative water production from each well.**

Figure 23: **Water bores in the PL 98 region**

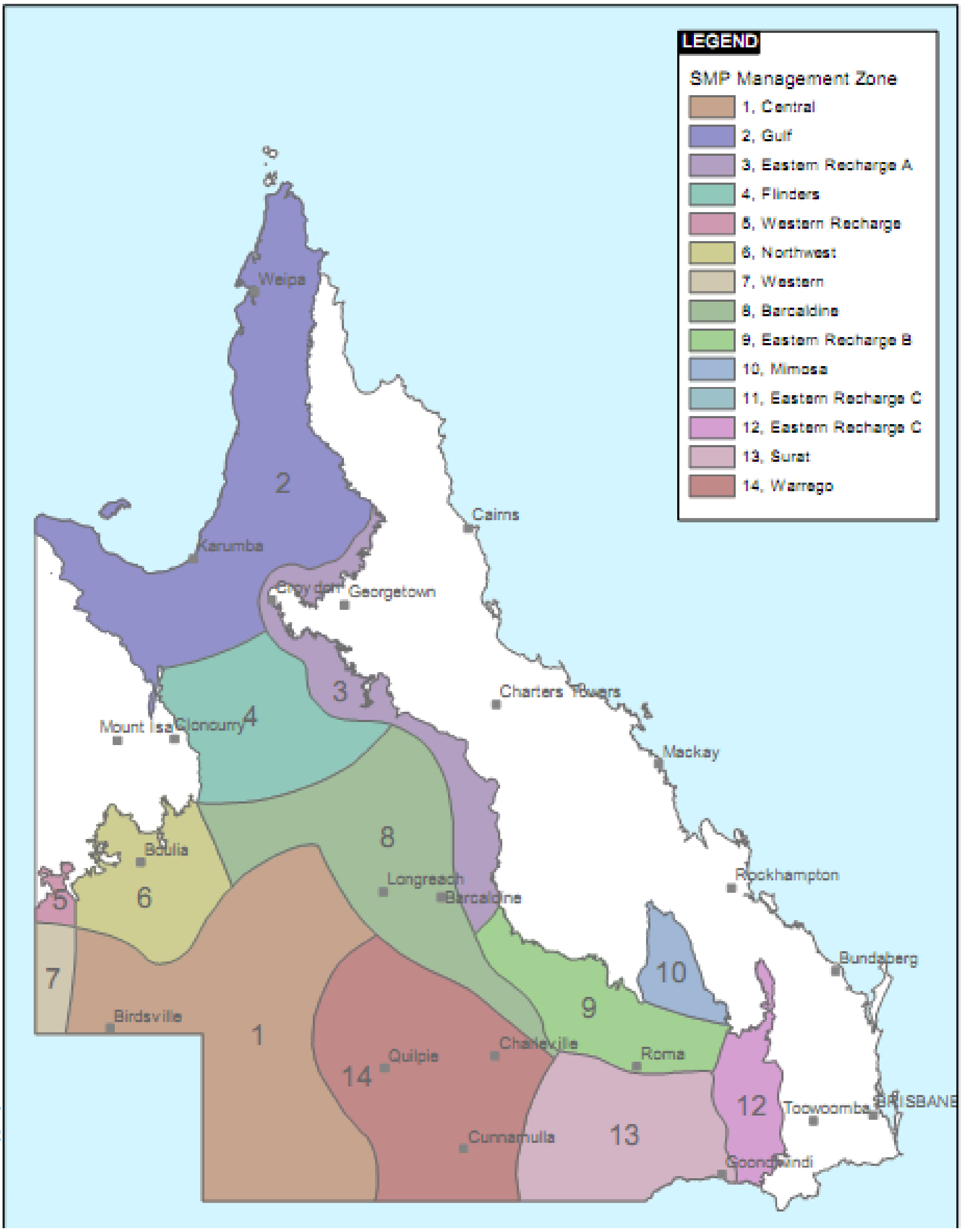

Figure 1: Strategic Management Plan Zones

(Qld DNRM, 2005)

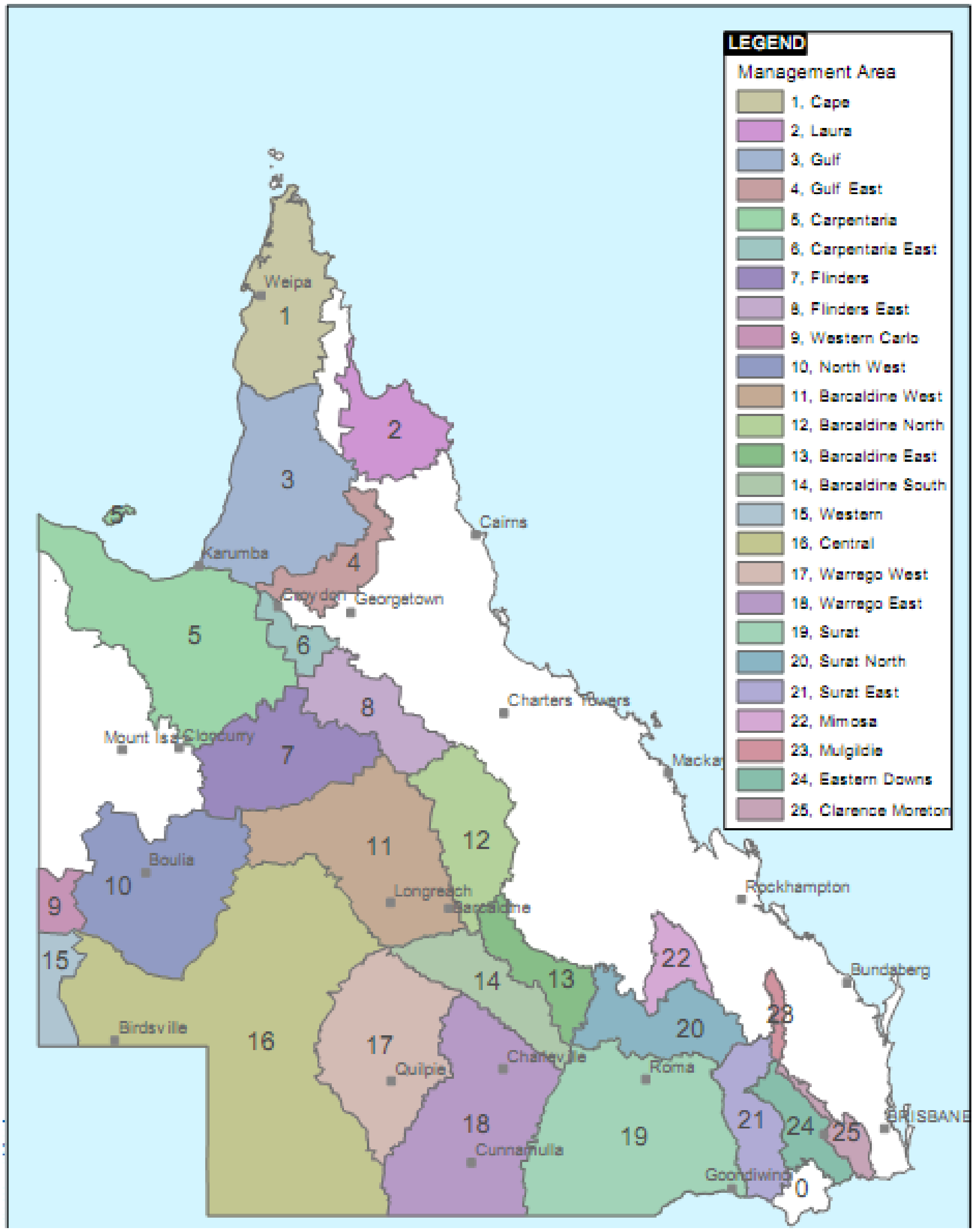

Figure 2: GAB WRP Management Areas

(Qld DNRM, 2005)

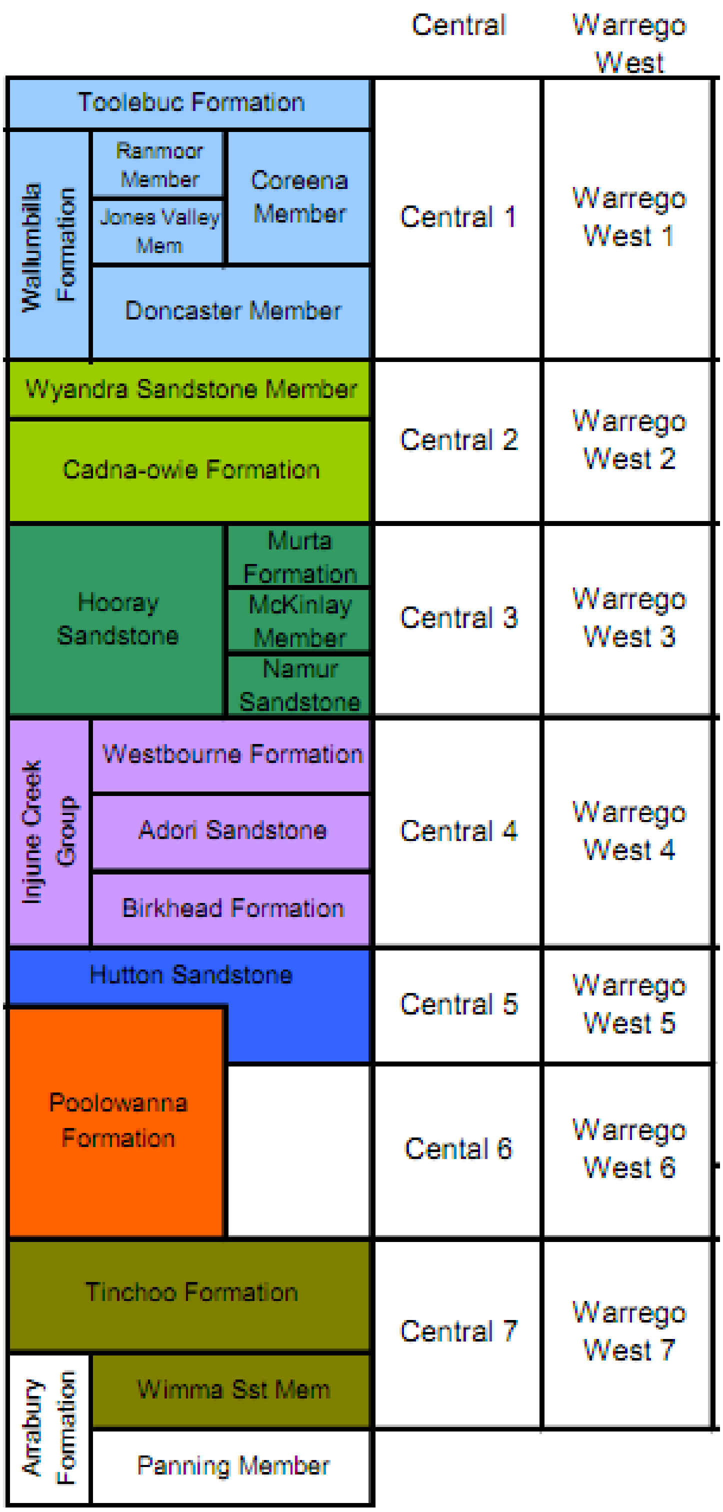

Figure 3: Correlation of the Management Units in the Eromanga Basin
(Qld DNRM, 2005)

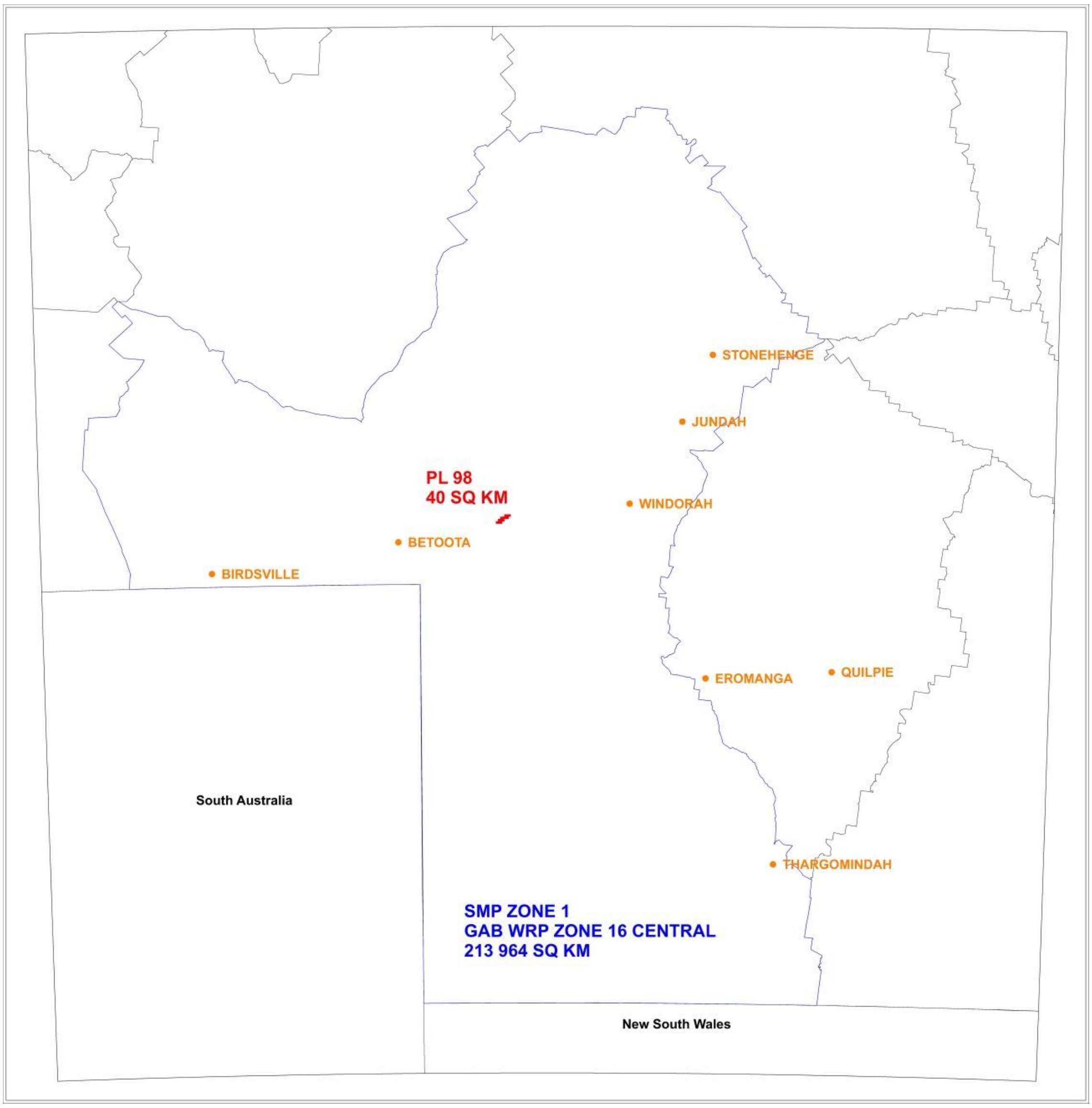

Figure 4: Tenement Location Map

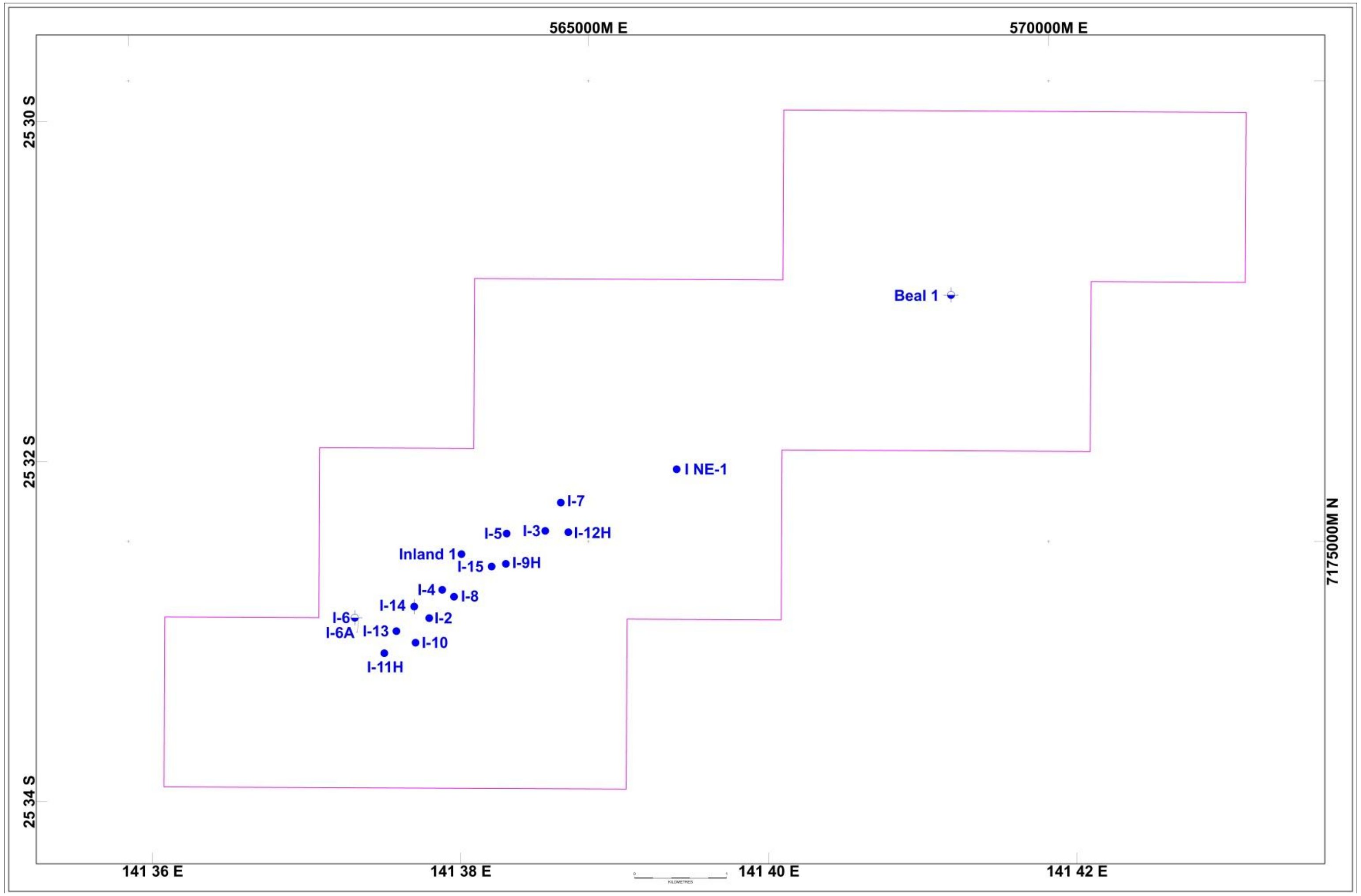

Figure 5: PL 98 Well Location Map

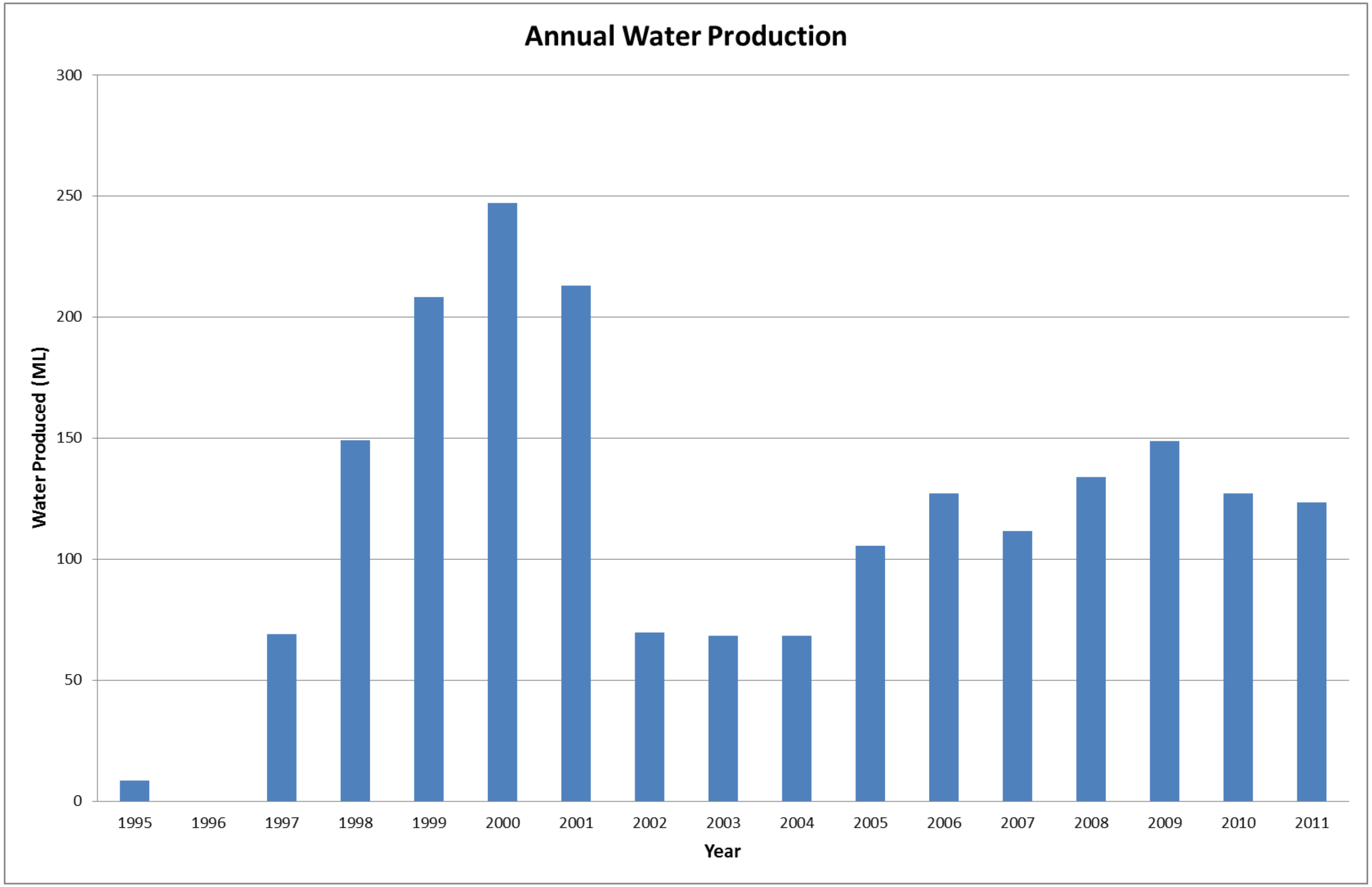

Figure 6: Yearly Associated Water Production

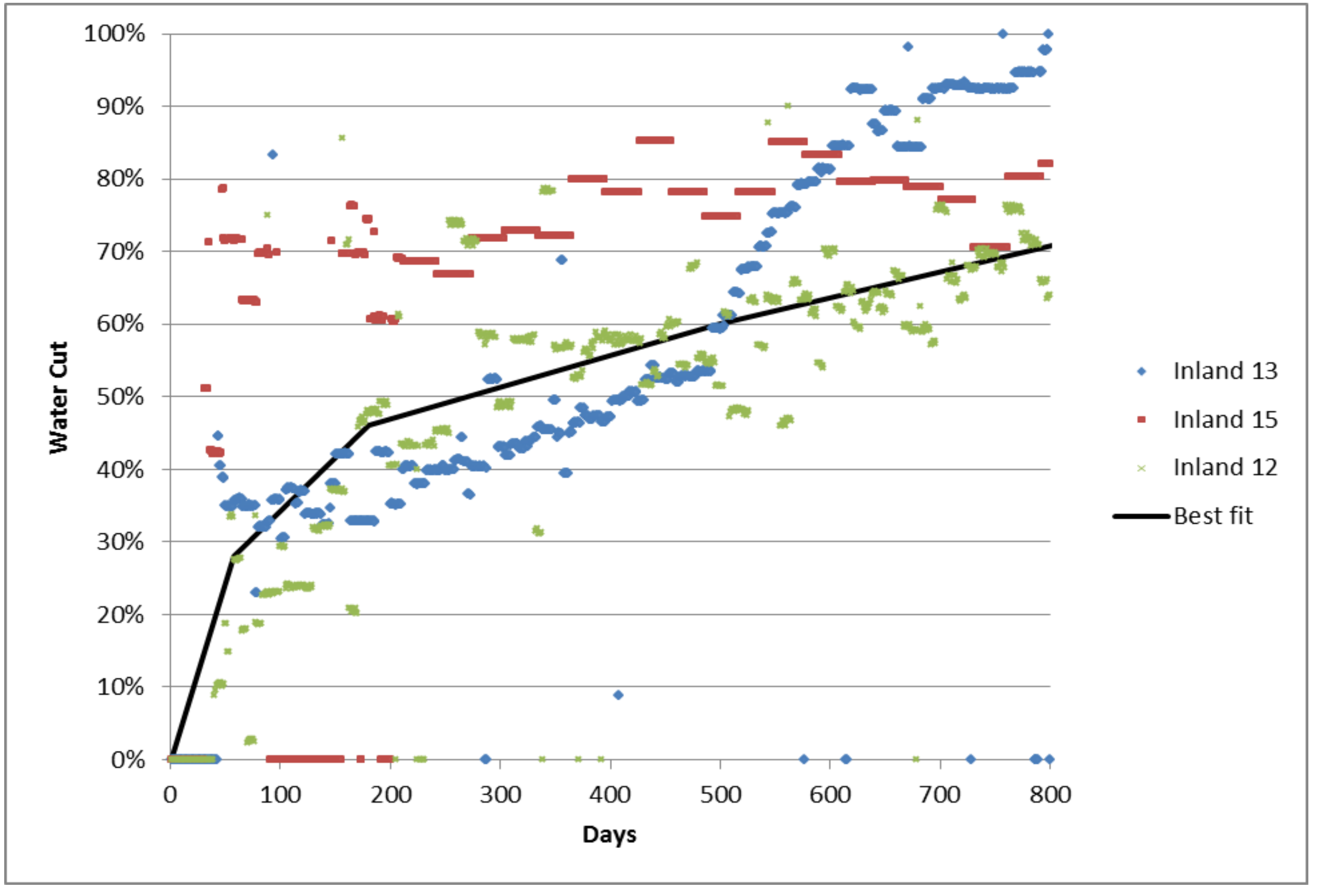

Figure 7: Water Production Graph

Water rates from the three most recent Hutton oil wells were used to predict future water production rates.

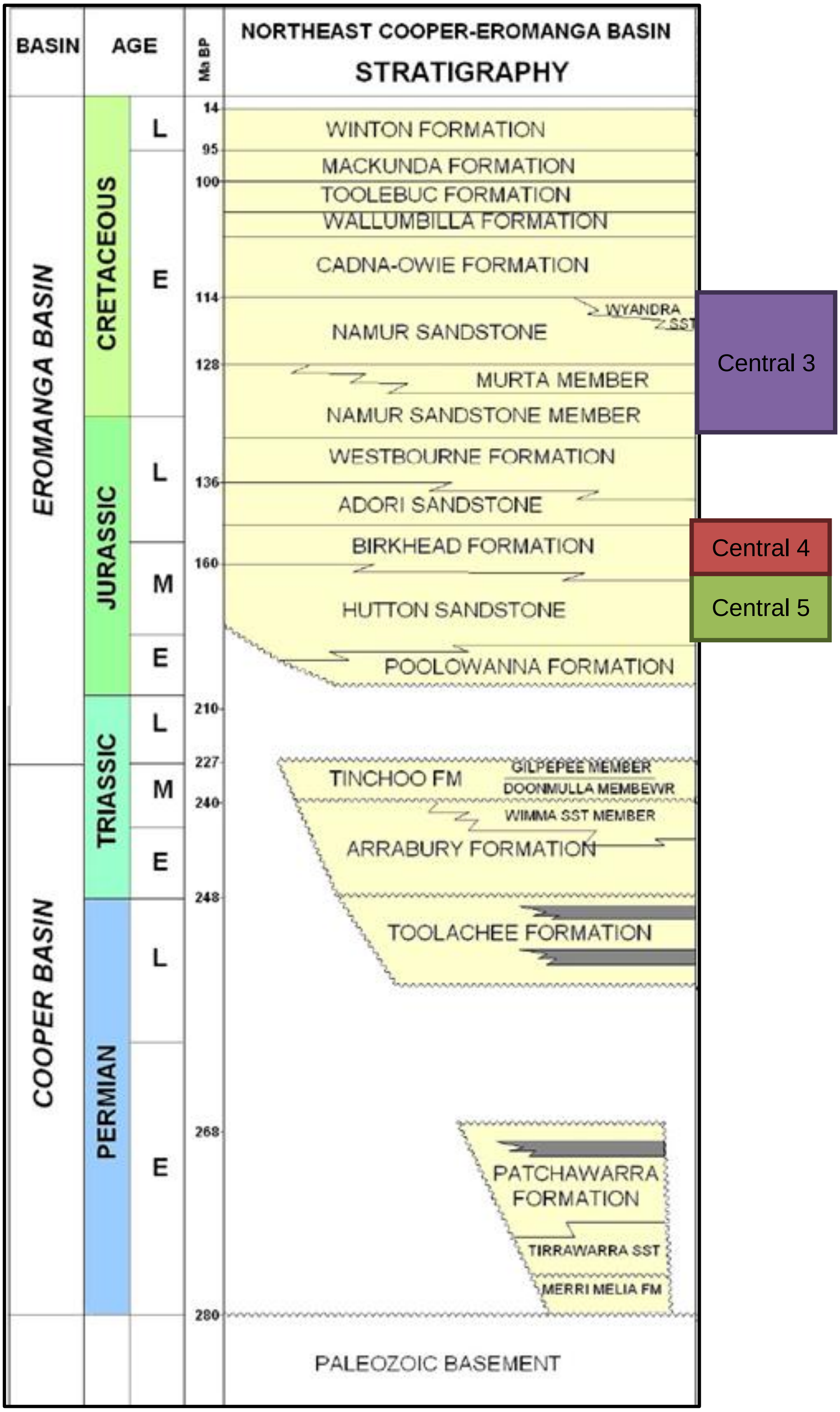

Figure 8: Stratigraphic Column

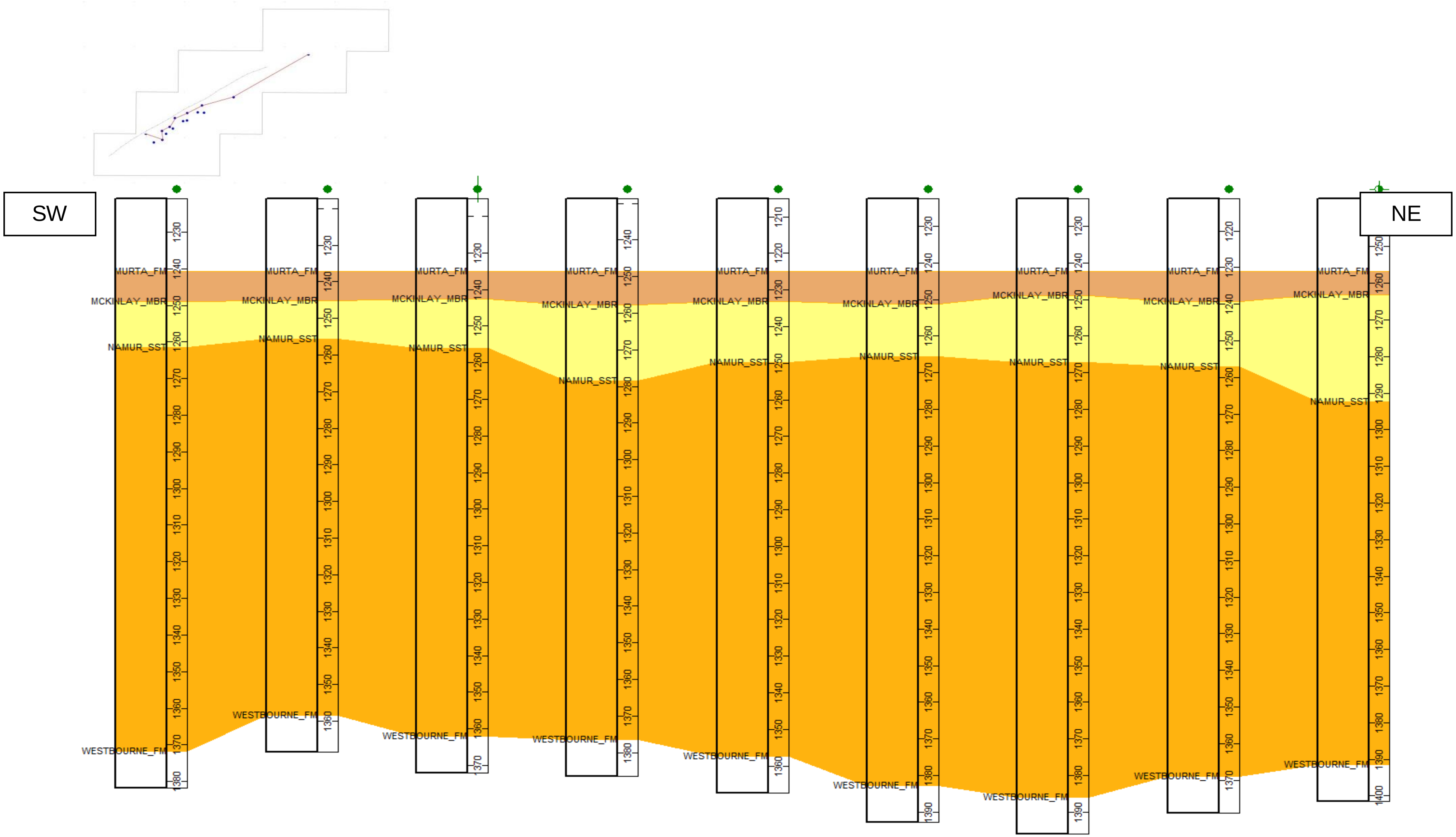

Figure 9: Schematic Cross-section of Central 3 across the Inland Oilfield (flattened on Murta Member)

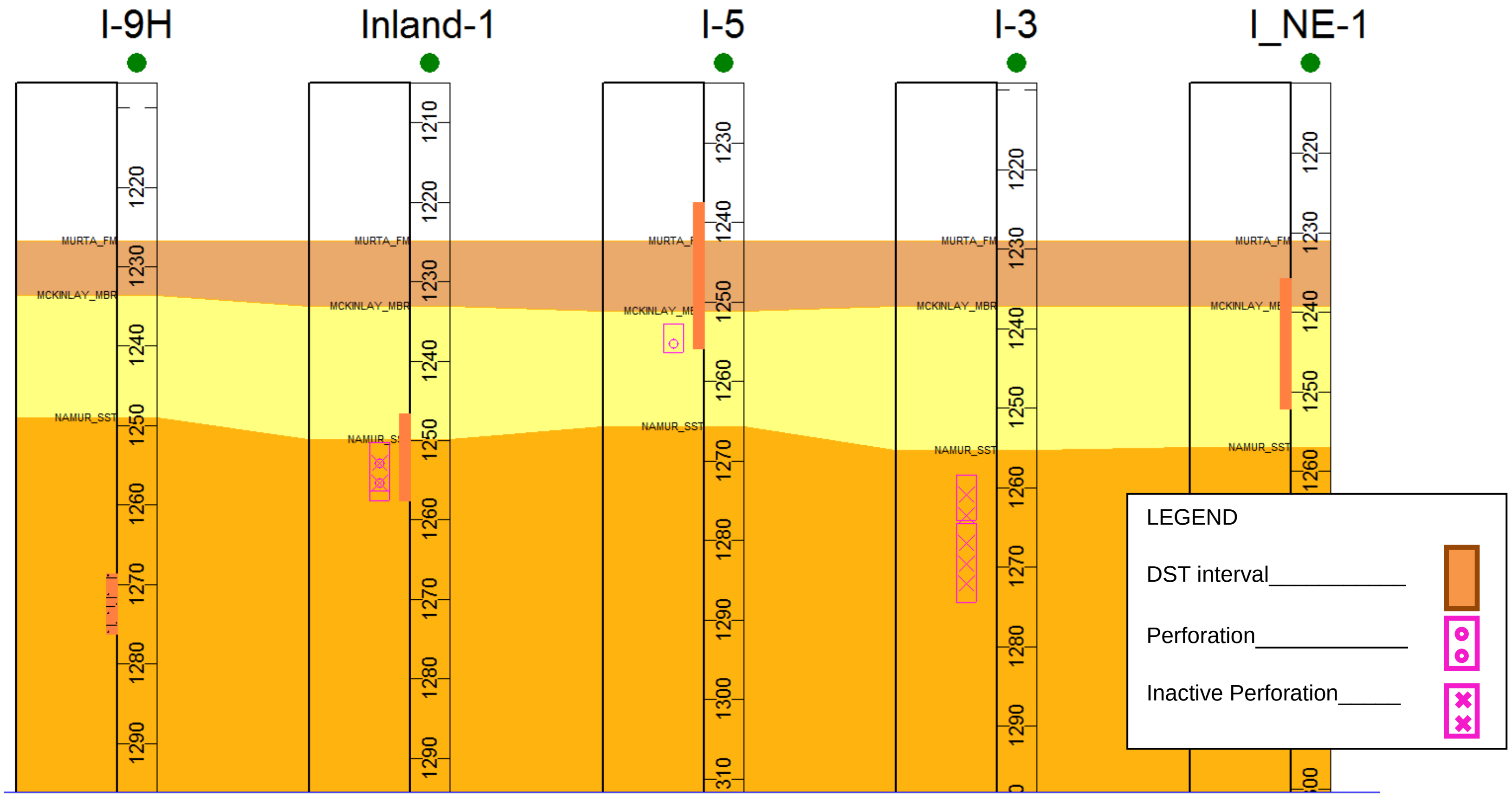

Figure 10: Cross-section of wells that have tested and/or perforated Central 3 reservoirs

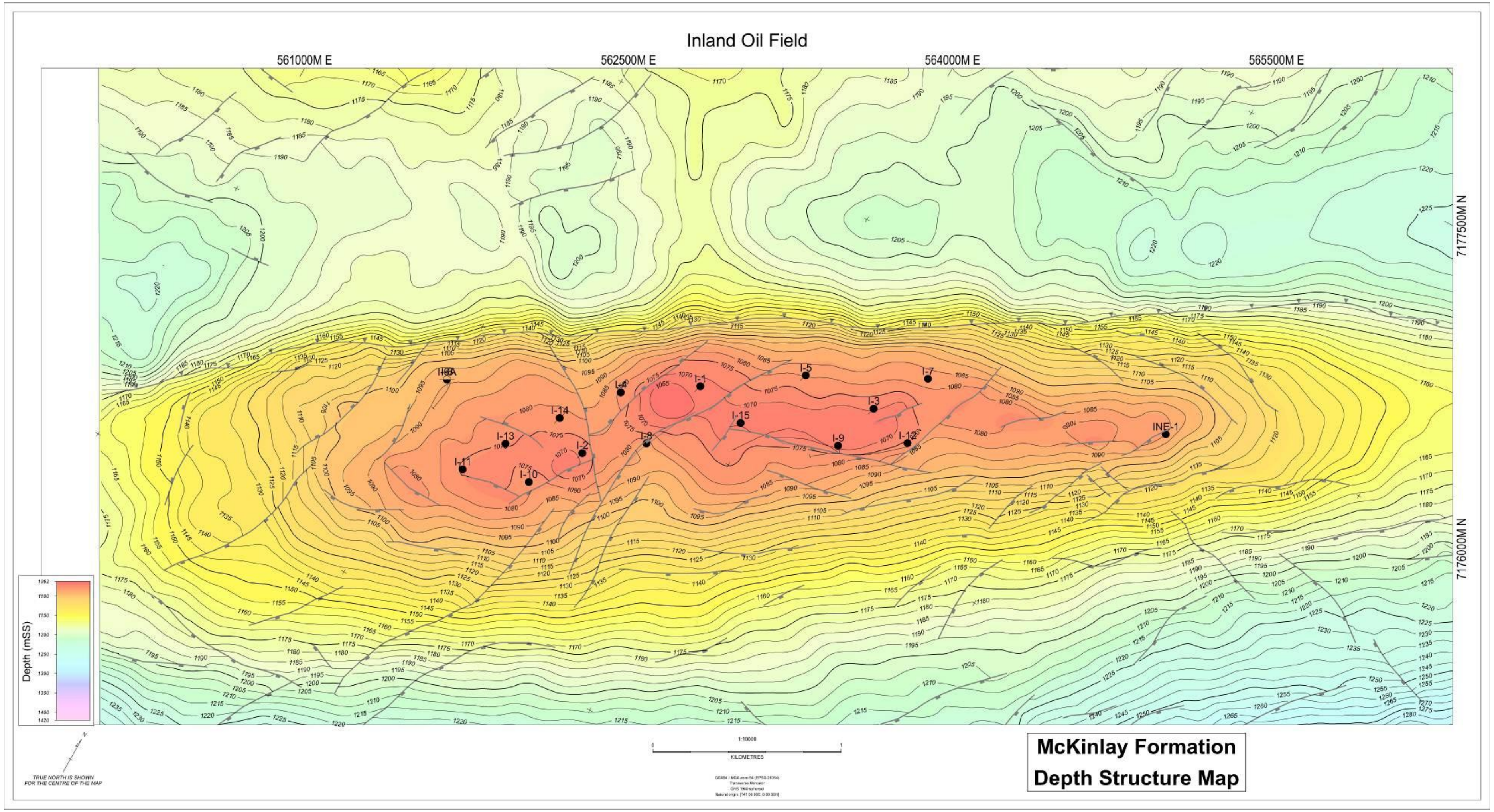

Figure 11: McKinlay Depth Structure Map

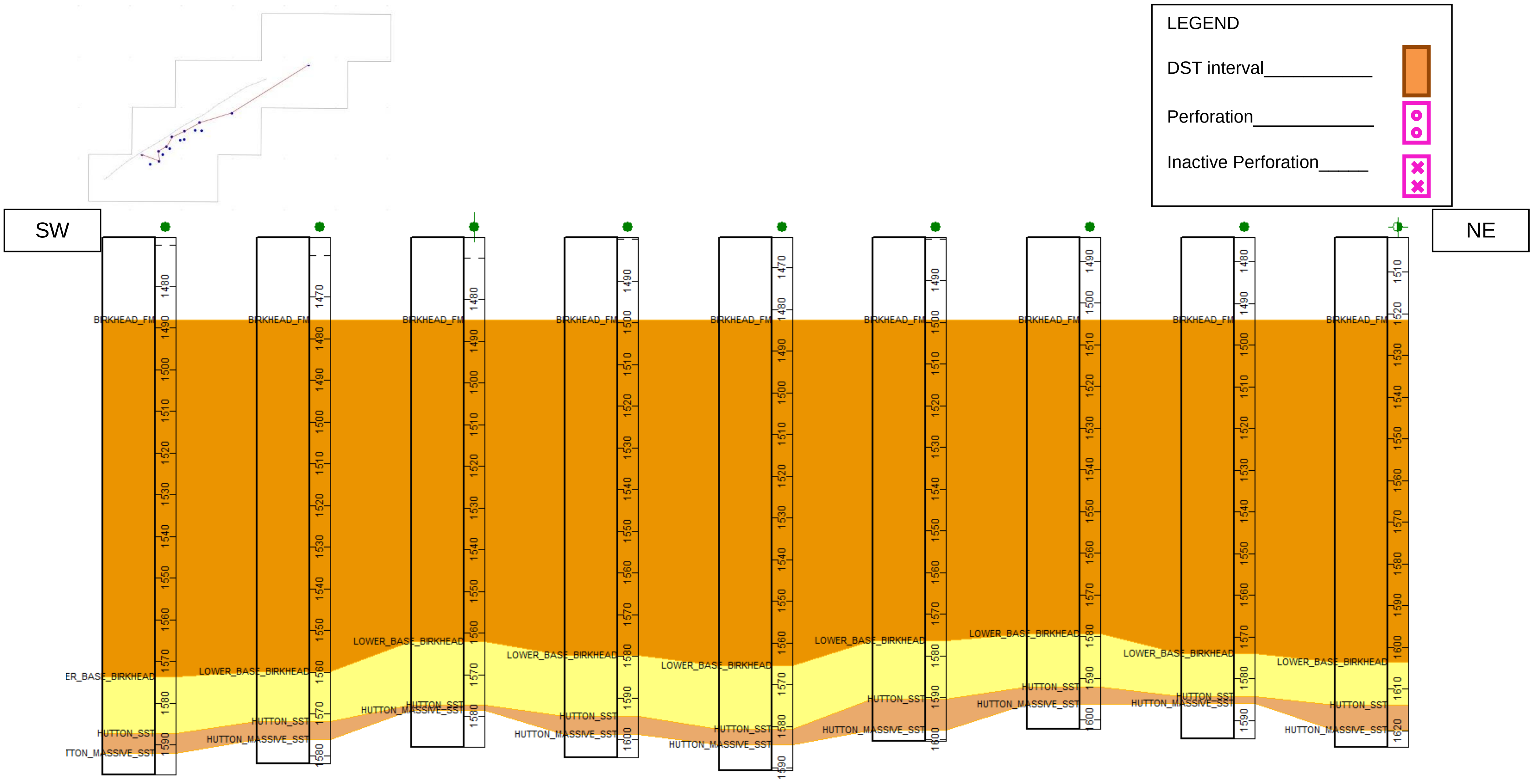

Figure 12: Schematic Cross-section of the Central 4 reservoir across the Inland Oilfield (flattened on Birkhead Formation)

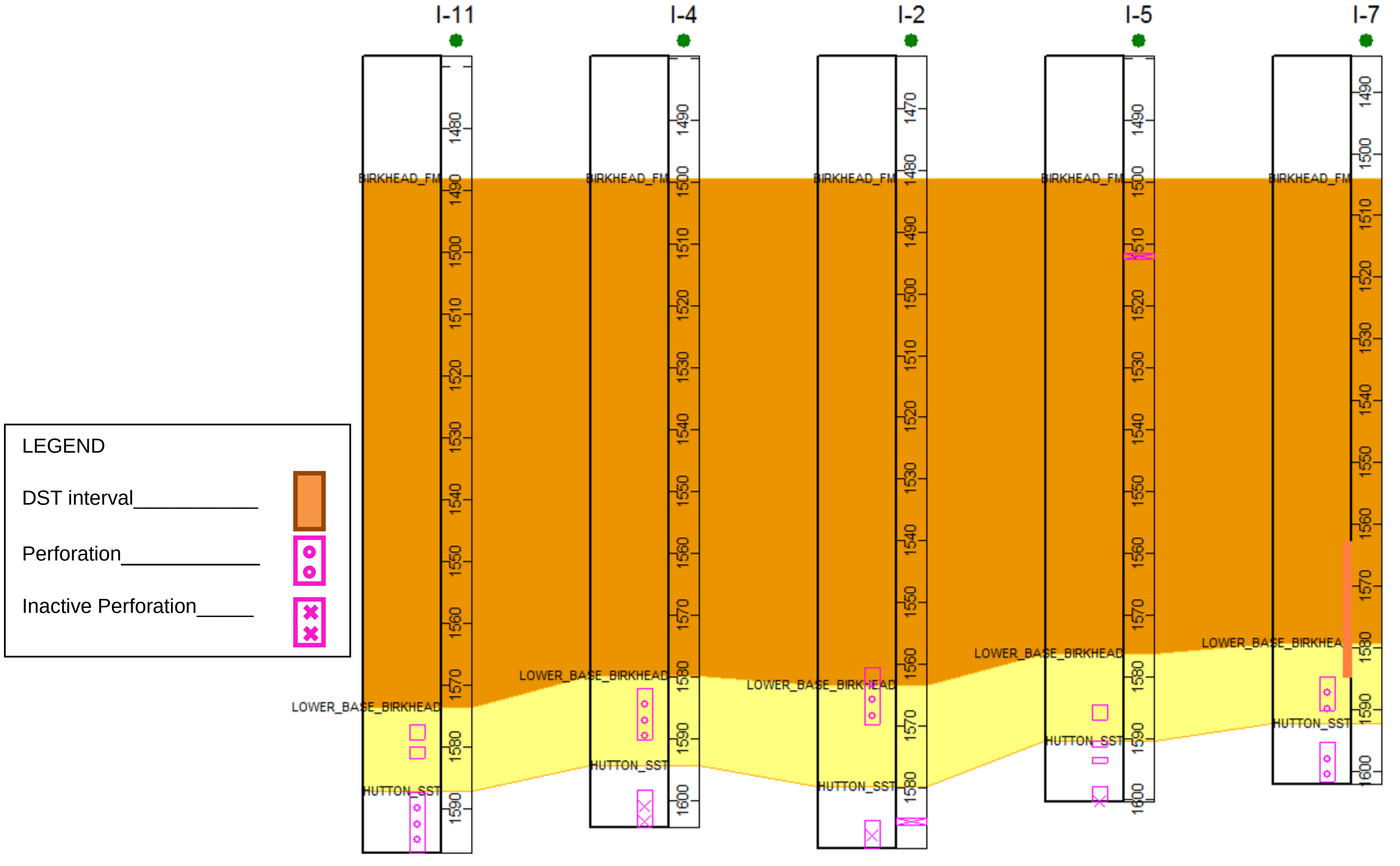

Figure 13: Wells that have perforated and/or tested the Central 4 reservoir

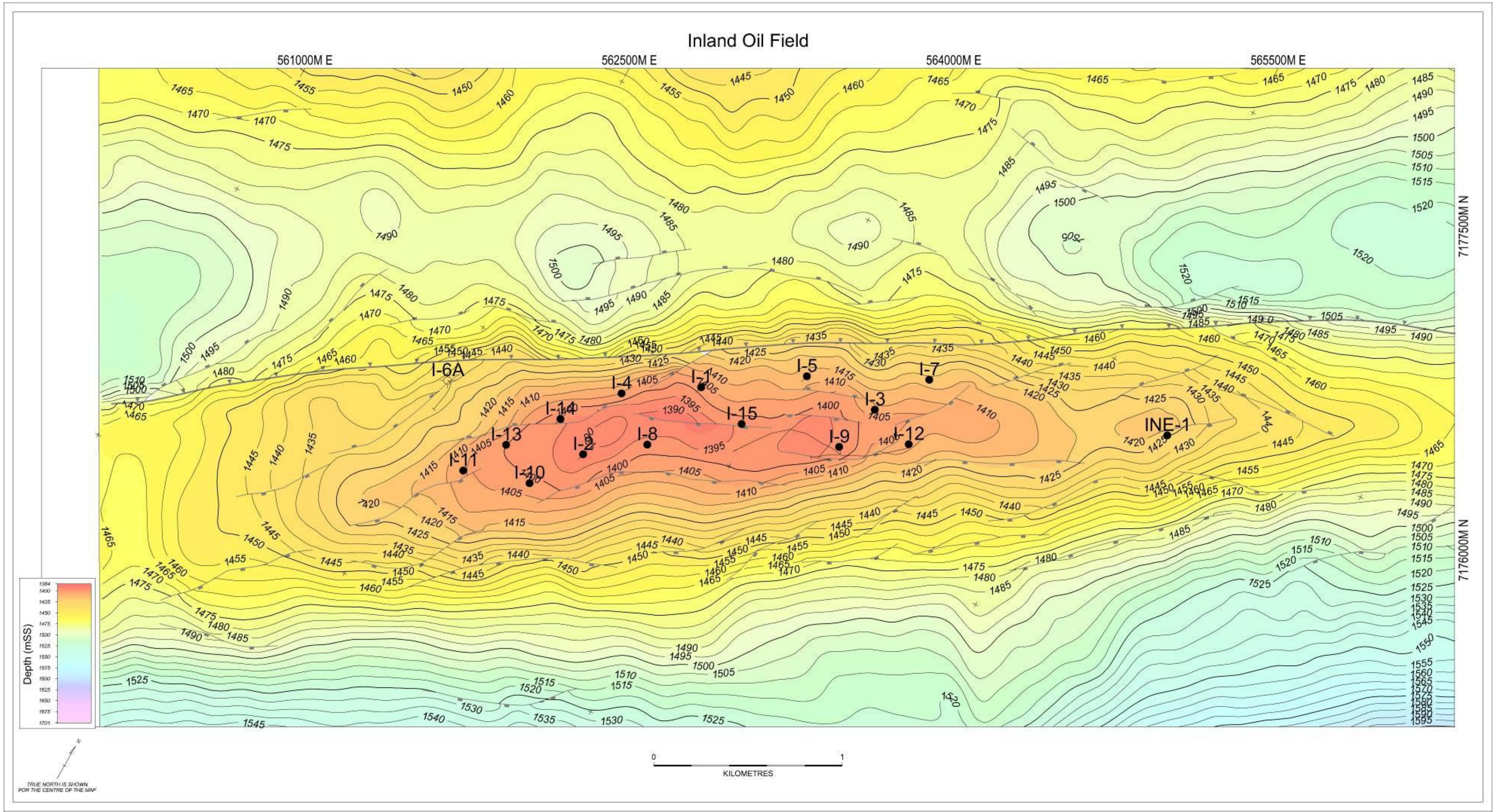

Figure 14: Lower Birkhead Depth Structure Map

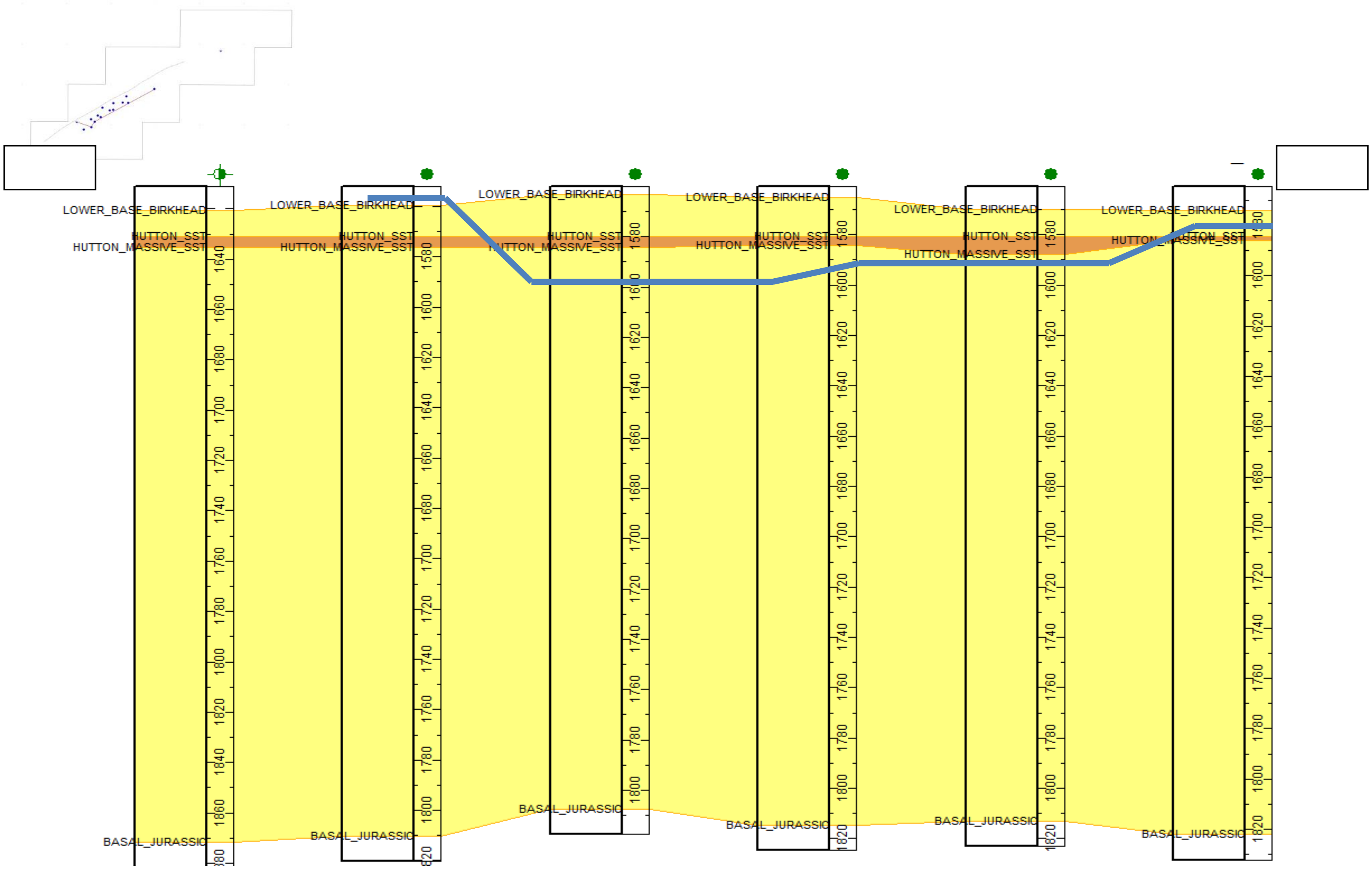

Figure 15: Schemeatic Cross-section of the Central 5 reservoir in the Inland Oilfield (flattened on Hutton Sandstone)

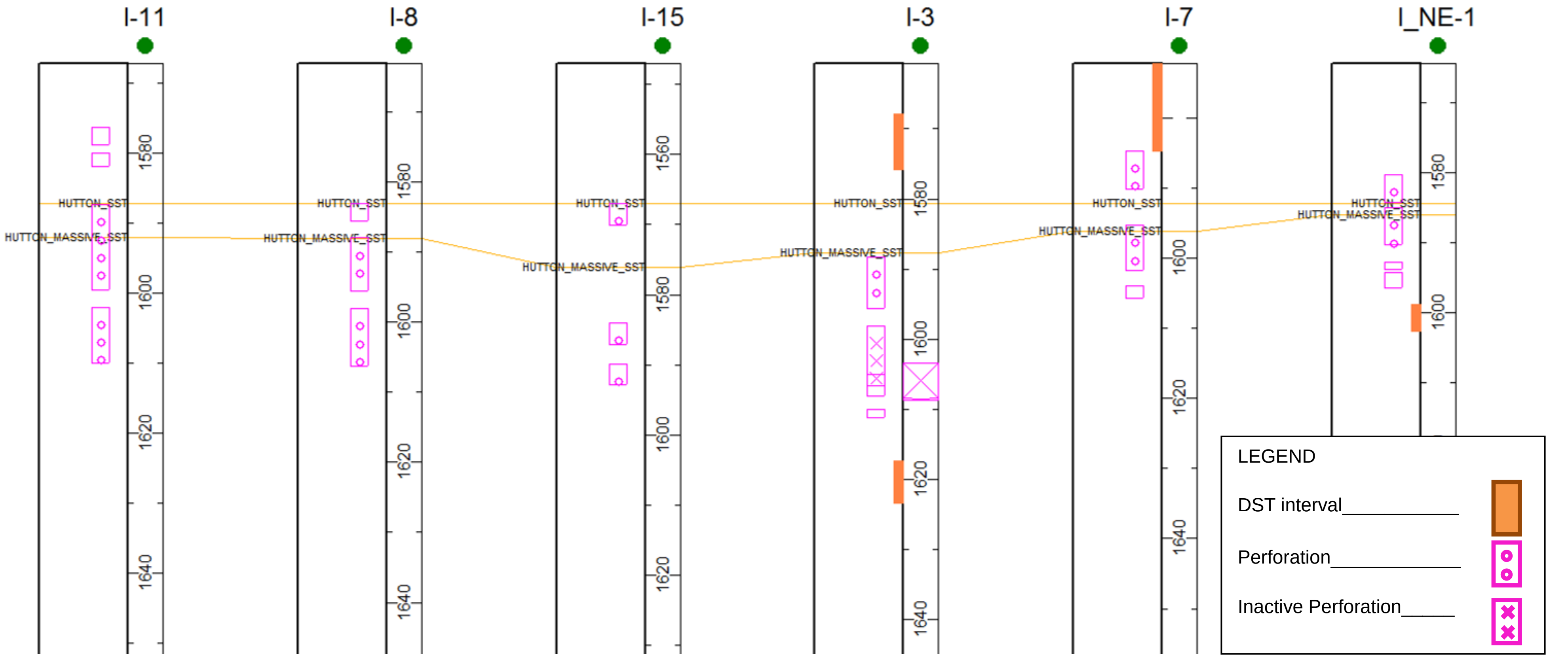

Figure 16: Wells with current production from Central 5 reservoir (flattened on Hutton Sandstone)

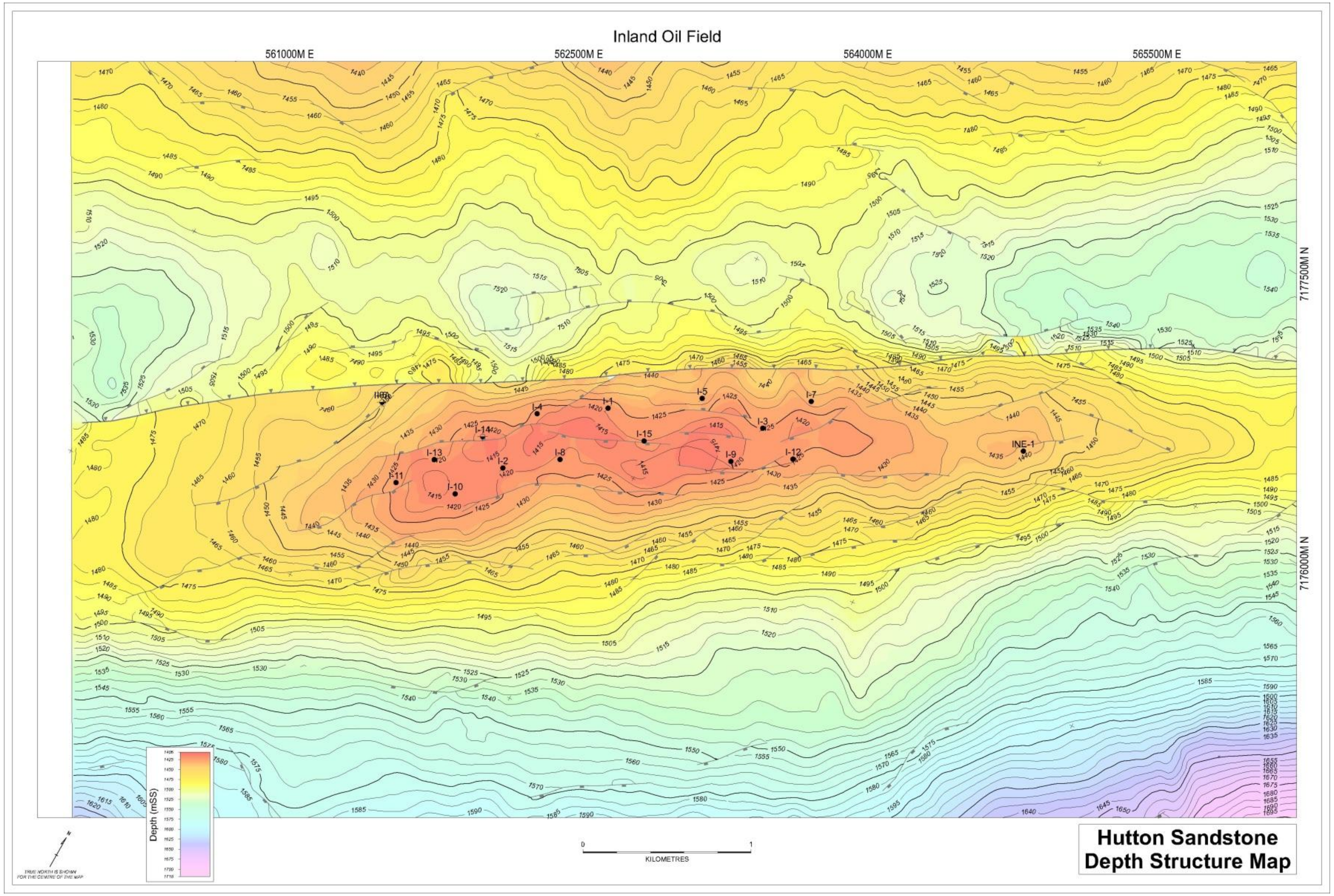

Figure 17: Hutton Depth Structure Map

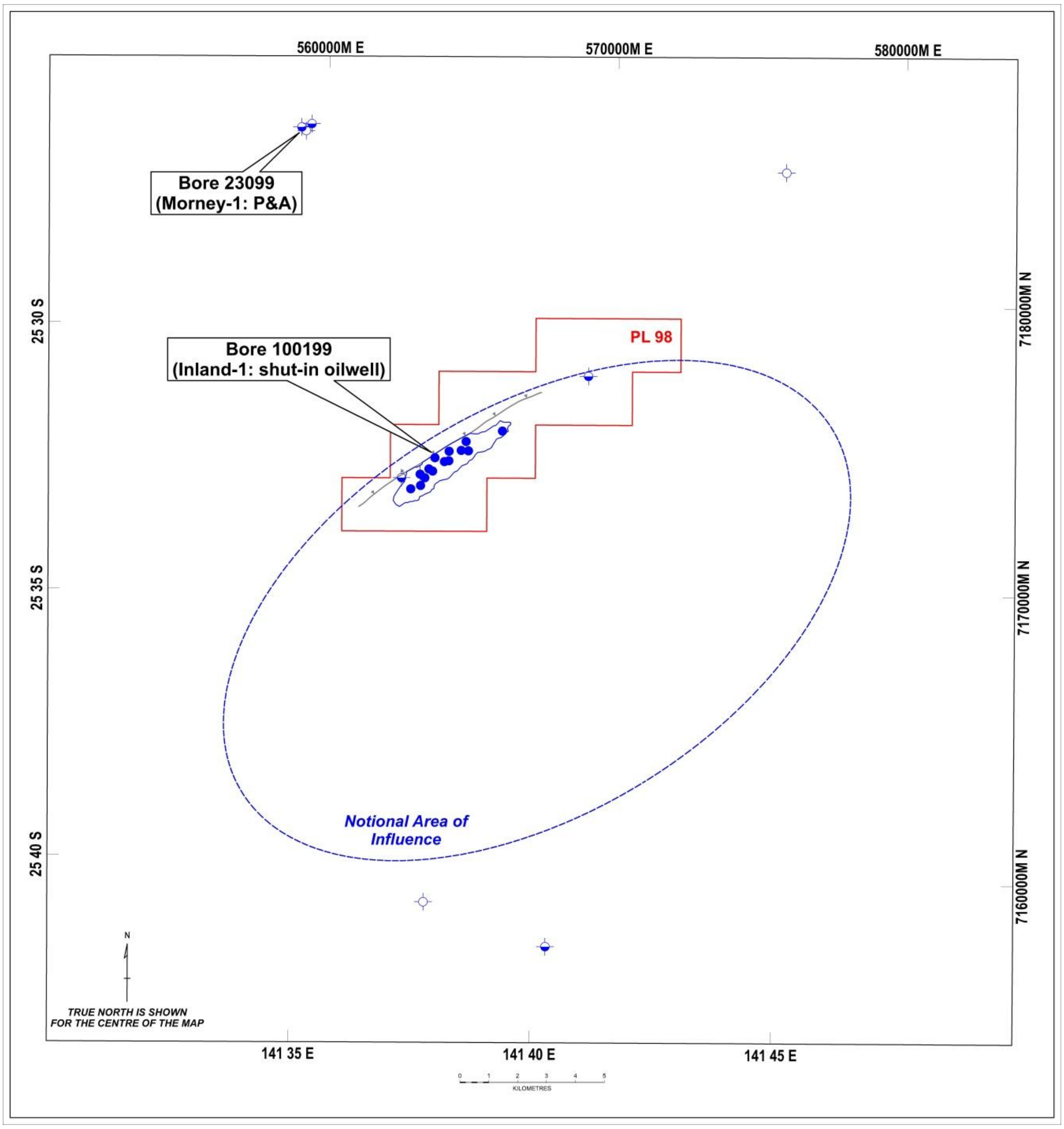

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Figure 18: Notional Area of Affected Aquifer

The notional area of affected aquifer relates mainly to the Hutton reservoir with less than half a percent of water production coming from the Birkhead reservoir. The notional area was defined in the northwest by the regional field bounding thrust fault, and then extended downdip in all directions by approximately 12 km. The reasoning here is that the Hutton Sandstone is a relatively homogeneous unit with good reservoir properties that results in good communication of fluids within the reservoir.

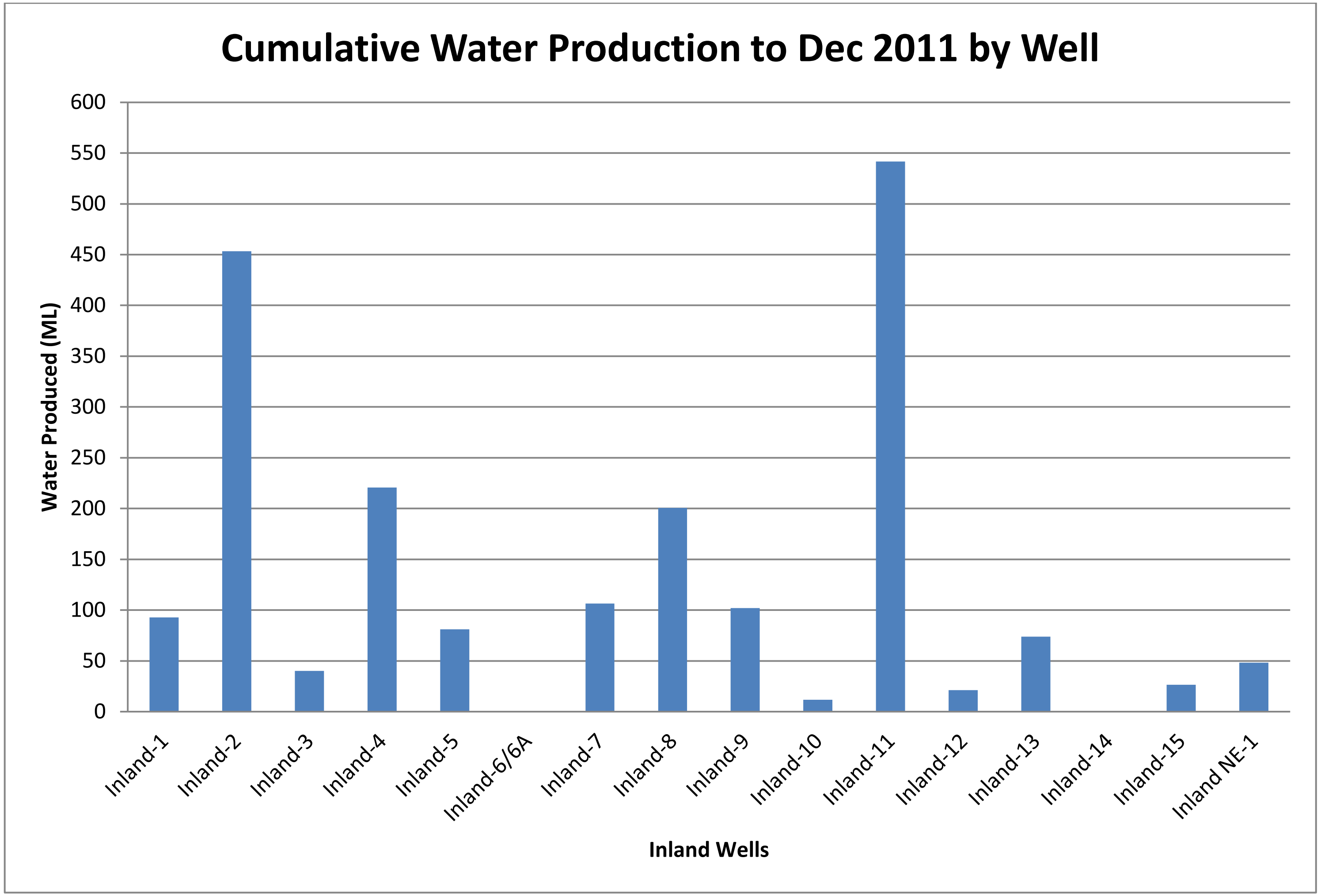

Figure 19: Cumulative Water Production for Individual Inland Wells (to Dec'11)

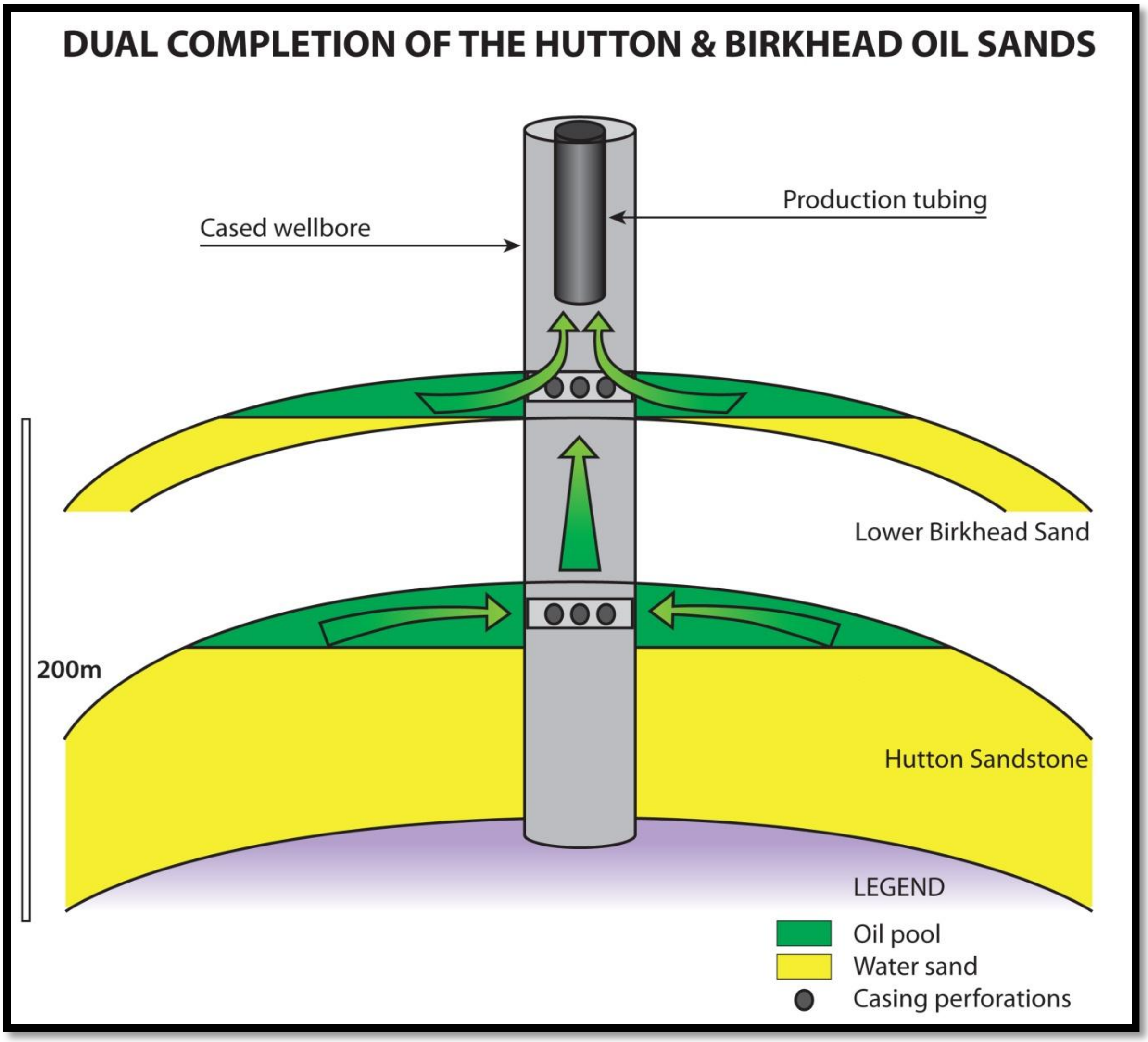

Figure 20: Comingled Production

The two reservoirs, Lower Birkhead Sand (part of Central 4) and the Hutton Sandstone (Central 5), are both exposed to the well borehole through perforations through the casing. All other formations/aquifers are isolated from the wellbore behind casing. As the production tubing is seated above the both formations, the total fluid contribution (both oil and associated water) are produced. This does not allow for determination of how much fluid each reservoir is contributing.

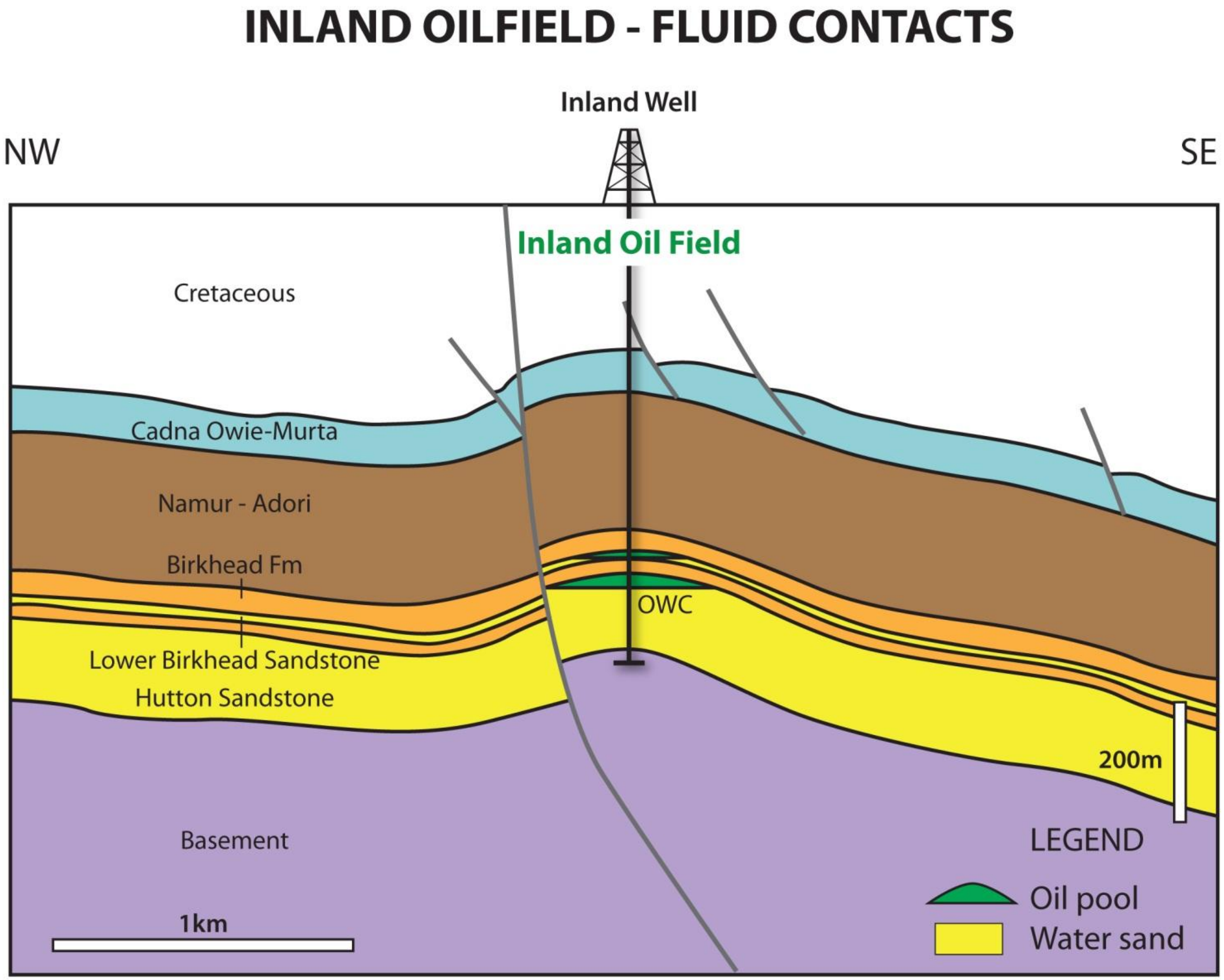

Figure 21: Schematic of Fluid Contacts in the Inland Oilfield

Schematic showing the relatively small upper part of the Hutton aquifer contains the oil pool. The extensive nature of the water-filled sandstone is also evident.

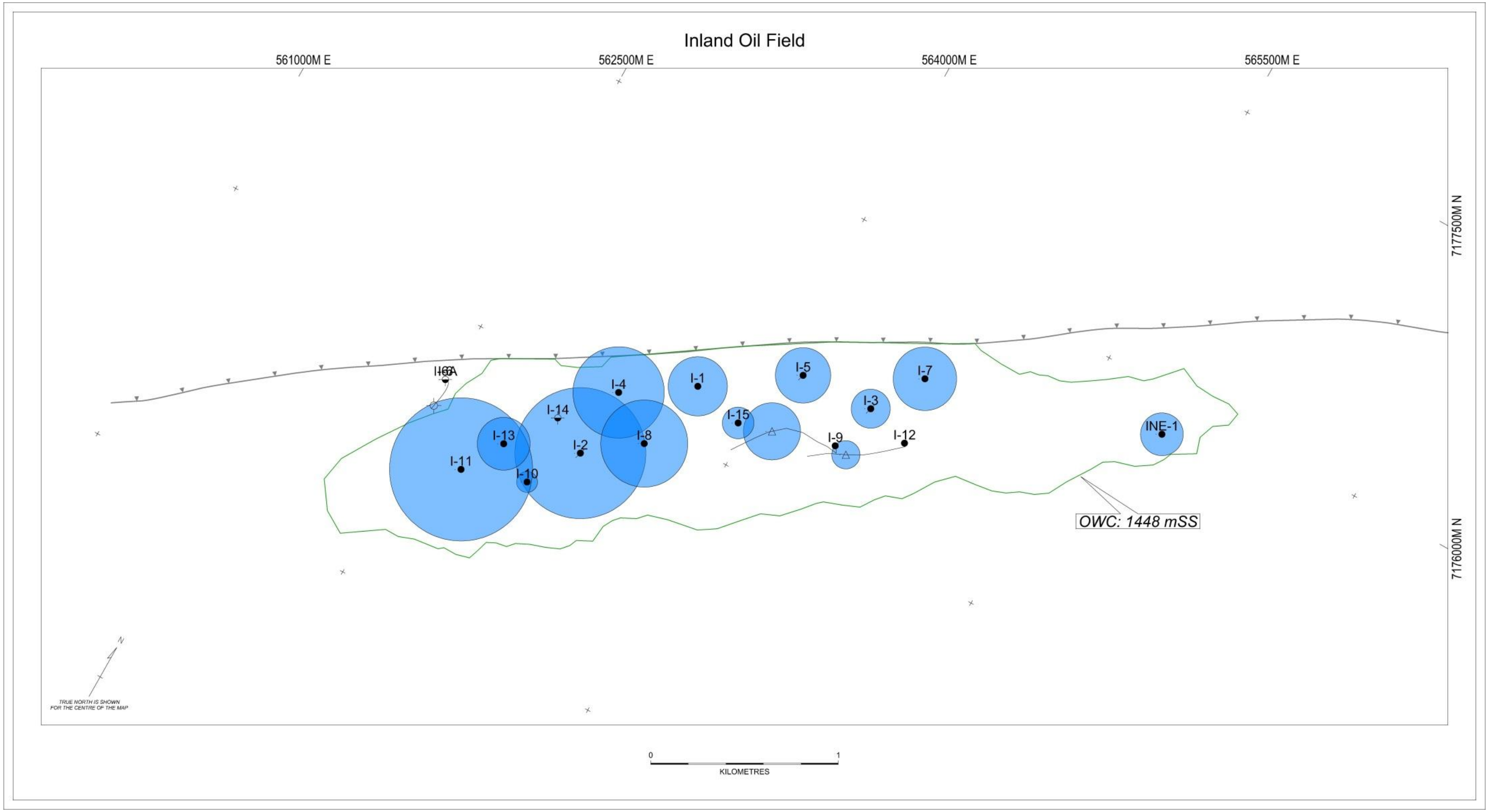

Figure 22: Bubble map showing relative water production from each well (to Dec'11).

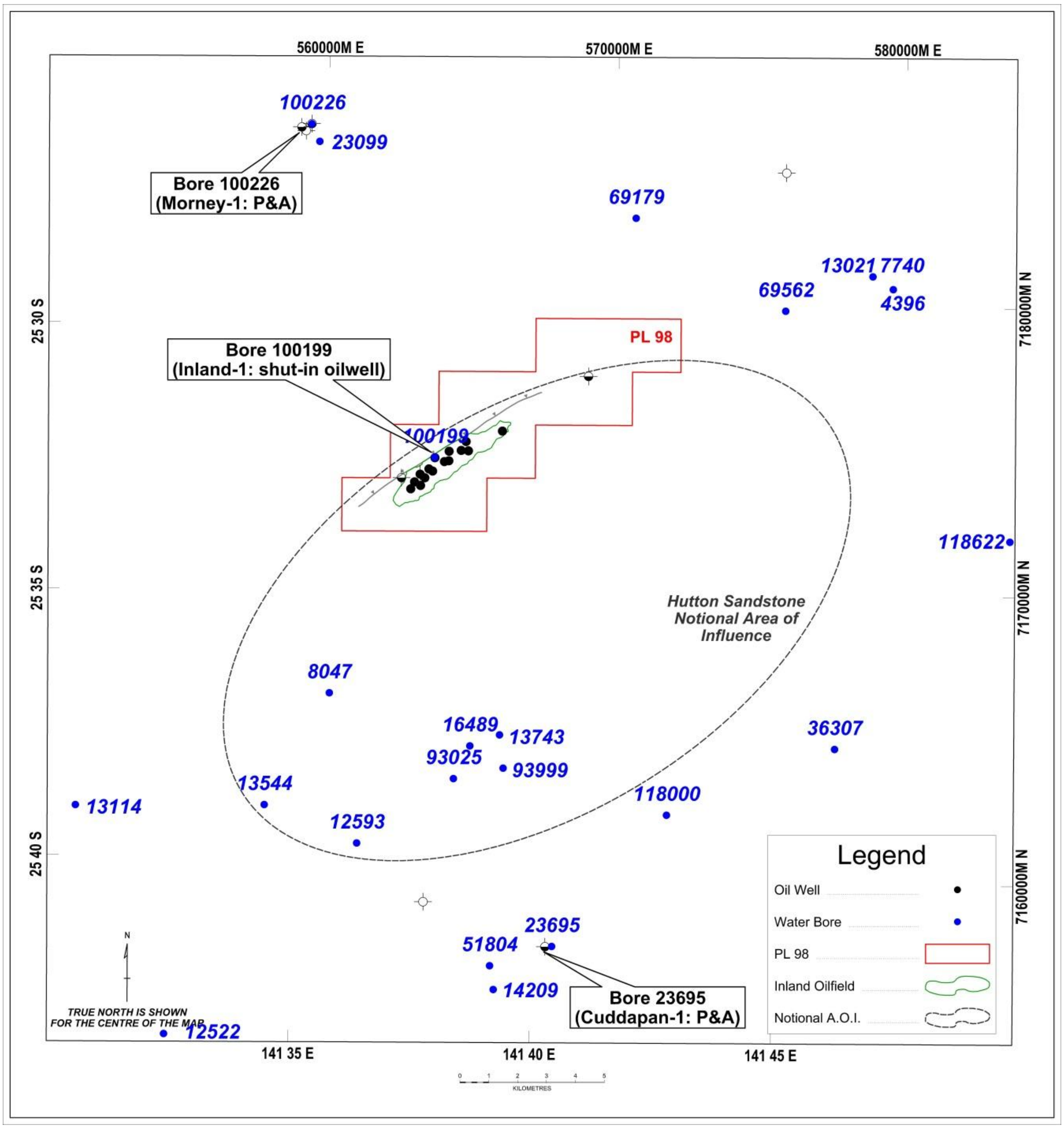

Figure 23: Water bore locations in the PL 98 region

Appendix 1 – Well Histories

Inland-1

- drilled in June 1994 and completed in July 1994 in the Namur Formation and the Hutton Sandstone
- March 1999, a swab test over the Namur -found not to be producing
- Namur was reperforated in January 2001 and in February 2001, the Namur was tested and flows 211 bpd with 100% water cut
- March 2002, the Namur was isolated in the annulus and the Hutton reopened
- May 2002 Hutton Test: 797 bpd 99.6% water cut
- June 2002 a downhole fault could not be resolved
- September 2002 the well was abandoned

Inland-2

- drilled in 1995 and completed in May 1995 over the Hutton
- 2002, the well watered out
- June 2006, plug set over the Hutton and the well was perforated in the Birkhead
- shut in November 2006
- August 2008 fracced
- December 2008 shut in with water flow rate of 75 bpd

Inland-3

- drilled in 1995 and completed in June 1995 over the Hutton Sandstone
- November 1995 Hutton plugged off
- December 1995, Namur perforated, flowed only water and the well was shut in

Inland-4

- Drilled in 1996 and completed in February 1996 in the Hutton Sandstone
- in 2001, the well watered out
- in June 2006, the Birkhead was perforated
- currently (December 2011) producing from the Birkhead Formation

Beal-1

- drilled in October 1996 and plugged and abandoned

Inland-5

- drilled in 1996 and completed in November 1996 in the Birkhead and Hutton sandstones
- the well watered out in 2002
- February 2003 – bride plugs were set plugging off the Birkhead and Hutton and the McKinlay formation was perforated
- 2006 production stoped: Records of oil rate of 15 bopd and little water prior. Both oil and water rates drop to 0. Interpreted as well shut in but no reason in the I.O.R. records were found as there was no evidence of watering out. Field staff advised the well kept pumping off.

Inland-6/6A

- drilled in Oct 1996; side-tracked in Nov 1996 and plugged & abandoned in mid Nov 1996.

Inland-7

- drilled in 1997 and completed in 1997 in the Birkhead and the Hutton
- currently (December 2011) producing from the Birkhead and Hutton

Inland-8

- drilled 1997 and completed in 1997 in the Hutton Sandstone,online with 13 bpd of associated water
- January 2001 the water cut went from 90% down to 75% after 6 months
- August 2003 Hutton Test at 397 bpd associated water
- currently (December 2011) producing from the Hutton

Inland-9

- horizontal well completed in April 2000 in the Hutton
- currently (December 2011) producing from the Hutton

Inland-10

- completed in March 2001 in the Hutton
- currently (December 2011) producing from the Hutton
- was only online for 2 weeks since Bridgeport acquired the field

Inland-11

- completed in February 2001 in the Birkhead and Hutton
- currently (December 2011) producing from the Birkhead and Hutton

Inland-12

- horizontal well completed in June 2002
- currently (December 2011) producing from the Hutton

Inland Northeast-1

- drilled in July 2002 and completed in August 2002 in the Hutton
- currently (December 2011) producing from the Hutton

Inland-13

- Completed May 2004 in the Hutton
- Has not been online since Bridgeport acquired the field

Inland-14

- December 2006 completed in the Hutton; no production to date from this suspended well

Inland-15

- December 2006 competed in the Hutton
- currently (December 2011) producing from the Hutton

Appendix 2 – Historical Water Production

Table 1: 1995

Month	Associated Water Produced	
	barrels	ML
Jul	824	0.13
Aug	10,210	1.62
Sep	13,066	2.08
Oct	17,158	2.73
Nov	12,920	2.05
Dec	0	0.00

Table 2: 1996

Month	Associated Water Produced	
	barrels	ML
Jan	0	0.00
Feb	0	0.00
Mar	0	0.00
Apr	0	0.00
May	0	0.00
Jun	0	0.00
Jul	0	0.00
Aug	0	0.00
Sep	0	0.00
Oct	0	0.00
Nov	0	0.00
Dec	0	0.00

Note: no information was supplied by IOR Exploration for this year

Table 3: 1997

Month	Associated Water Produced	
	barrels	ML
Jan	0	0.00
Feb	3	0.00
Mar	47,740	7.59
Apr	23,142	3.68
May	23,824	3.79
Jun	4,230	0.67
Jul	51,144	8.13
Aug	48,536	7.72
Sep	46,033	7.32
Oct	46,284	7.36
Nov	68,366	10.87
Dec	74,203	11.80

Table 4: 1998

Month	Associated Water Produced	
	barrels	ML
Jan	23,201	3.69
Feb	71,381	11.35
Mar	89,898	14.29
Apr	82,741	13.15
May	85,578	13.61
Jun	60,460	9.61
Jul	88,018	13.99
Aug	94,483	15.02
Sep	83,443	13.27
Oct	86,569	13.76
Nov	82,911	13.18
Dec	88,956	14.14

Table 5: 1999

Month	Associated Water Produced	
	barrels	ML
Jan	90,029	14.31
Feb	79,527	12.64
Mar	99,605	15.84
Apr	115,174	18.31
May	124,878	19.85
Jun	115,606	18.38
Jul	139,550	22.19
Aug	90,683	14.42
Sep	87,102	13.85
Oct	98,925	15.73
Nov	136,881	21.76
Dec	132,280	21.03

Table 6: 2000

Month	Associated Water Produced	
	barrels	ML
Jan	158,866	25.26
Feb	130,691	20.78
Mar	155,253	24.68
Apr	149,245	23.73
May	118,508	18.84
Jun	75,917	12.07
Jul	97,333	15.47
Aug	138,215	21.97
Sep	163,906	26.06
Oct	139,882	22.24
Nov	112,165	17.83

Dec	115,300	18.33

Table 7: 2001

Month	Associated Water Produced	
	barrels	ML
Jan	125,564	19.96
Feb	133,130	21.17
Mar	123,791	19.68
Apr	112,212	17.84
May	112,653	17.91
Jun	102,048	16.22
Jul	102,417	16.28
Aug	120,028	19.08
Sep	102,531	16.30
Oct	97,920	15.57
Nov	92,187	14.66
Dec	114,990	18.28

Table 8: 2002

Month	Associated Water Produced	
	barrels	ML
Jan	46,938	7.46
Feb	27,408	4.36
Mar	57,903	9.21
Apr	56,761	9.02
May	34,890	5.55
Jun	32,492	5.17
Jul	37,950	6.03
Aug	29,596	4.71
Sep	25,325	4.03
Oct	32,474	5.16
Nov	30,605	4.87
Dec	24,880	3.96

Table 9: 2003

Month	Associated Water Produced	
	barrels	ML
Jan	19,567	3.11
Feb	29,453	4.68
Mar	33,281	5.29
Apr	34,393	5.47
May	38,364	6.10
Jun	45,525	7.24
Jul	60,652	9.64
Aug	36,951	5.87
Sep	32,606	5.18
Oct	33,470	5.32
Nov	32,709	5.20

Dec	32,894	5.23

Table 10: 2004

Month	Associated Water Produced	
	barrels	ML
Jan	33,854	5.38
Feb	32,055	5.10
Mar	35,494	5.64
Apr	39,107	6.22
May	36,263	5.77
Jun	37,228	5.92
Jul	33,646	5.35
Aug	33,220	5.28
Sep	28,984	4.61
Oct	39,159	6.23
Nov	41,933	6.67
Dec	39,268	6.24

Table 11: 2005

Month	Associated Water Produced	
	barrels	ML
Jan	38,713	6.15
Feb	39,815	6.33
Mar	44,744	7.11
Apr	45,533	7.24
May	41,775	6.64
Jun	44,233	7.03
Jul	43,780	6.96
Aug	61,422	9.77
Sep	75,103	11.94
Oct	83,520	13.28
Nov	72,706	11.56
Dec	72,584	11.54

Table 12: 2006

Month	Associated Water Produced	
	barrels	ML
Jan	70,003	11.13
Feb	55,706	8.86
Mar	75,920	12.07
Apr	72,645	11.55
May	67,427	10.72
Jun	73,880	11.75
Jul	66,062	10.50
Aug	69,646	11.07
Sep	66,221	10.53
Oct	60,609	9.64
Nov	57,144	9.09

Dec	65,225	10.37

Table 13: 2007

Month	Associated Water Produced	
	barrels	ML
Jan	63,199	10.05
Feb	59,729	9.50
Mar	51,456	8.18
Apr	51,570	8.20
May	62,722	9.97
Jun	52,752	8.39
Jul	55,115	8.76
Aug	55,978	8.90
Sep	75,037	11.93
Oct	63,571	10.11
Nov	44,203	7.03
Dec	66,513	10.57

Table 14: 2008

Month	Associated Water Produced	
	barrels	ML
Jan	63,689	10.13
Feb	66,972	10.65
Mar	69,321	11.02
Apr	74,877	11.90
May	76,432	12.15
Jun	86,499	13.75
Jul	69,272	11.01
Aug	101,603	16.15
Sep	61,382	9.76
Oct	55,918	8.89
Nov	57,260	9.10
Dec	58,636	9.32

Table 15: 2009

Month	Associated Water Produced	
	barrels	ML
Jan	42,037	6.68
Feb	58,309	9.27
Mar	80,325	12.77
Apr	80,020	12.72
May	84,138	13.38
Jun	79,745	12.68
Jul	57,070	9.07
Aug	47,605	7.57
Sep	118,026	18.76
Oct	99,152	15.76
Nov	94,341	15.00

Dec	95,847	15.24

Table 16: 2010

Month	Associated Water Produced	
	barrels	ML
Jan	79,228	12.60
Feb	61,398	9.76
Mar	50,601	8.04
Apr	54,182	8.61
May	67,882	10.79
Jun	76,249	12.12
Jul	83,219	13.23
Aug	29,696	4.72
Sep	75,319	11.97
Oct	81,951	13.03
Nov	71,485	11.37
Dec	69,417	11.04

Table 17: 2011

Month	Associated Water Produced	
	barrels	ML
Jan	50,860	8.09
Feb	59,122	9.40
Mar	79,189	12.59
Apr	45,537	7.24
May	76,326	12.13
Jun	69,059	10.98
Jul	69,242	11.01
Aug	67,502	10.73
Sep	62,415	9.92
Oct	63,375	10.08
Nov	62,318	9.91
Dec	71,020	11.29

Appendix 3 – Namur Water Analysis

Inland-1

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Water Analysis Report   Job No. LQ3157   Method WAT 2

Sample ID.   Inland-1, DST-2 Water Sample

Chemical Composition

		mg/L	me/L
Cations			
Calcium	(Ca)	207.0	10.33
Magnesium	(Mg)	24.0	1.98
Sodium	(Na)	3570.0	155.28
Potassium	(K)	11610.0	296.93
Anions			
Hydroxide	(OH)		
Carbonate	(CO3)		
Bi-Carbonate	(HCO3)	1443.2	23.66
Sulphate	(SO4)	1140.0	23.74
Chloride	(Cl)	14889	419.41
Nitrate	(NO3)	<0.1	
Bromide	(Br)	69.0	

Other Analyses

Reaction - pH	7.8
Conductivity (E.C.) (micro -S/cm at 25 degC)	45700
Resistivity (Ohm.M at 25 degC)	0.22

Derived Data

	mg/L
Total Dissolved Solids	
A. Based on E.C.	29248
B. Calculated (HCO3=CO3)	32162
Total Hardness	616
Carbonate Hardness	616
Non-Carbonate Hardness	
Total Alkalinity	1312
(Each as CaCO3)	

Totals and Balance

Cations (me/L)	464.5	Diff=	2.29
Anions (me/L)	466.8	Sum =	931.33

ION BALANCE (Diff*100/Sum) = 0.25%

Sodium / Total Cation Ratio 33.4%

Remarks

Note: mg/L = Milligrams per litre
me/L = MilliEqivs.per litre

Name: Owen Nugent
Address: IOR Exploration
39 Byron Street Bulimba
Brisbane QLD 4171

Date Collected 27/06/94
Date Received 26/07/94
Collected by CLIENT

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TABLE 1 - WATER ANALYSIS

JOB NUMBER: LQ9065

WELL / ID: INLAND-9, DST-1
SAMPLE TYPE: Recovery
SAMPLE POINT: Manifold
DATE COLLECTED: 22/04/00
DATE RECEIVED: 25/05/00

FORMATION: Namur
INTERVAL: 4162'-4187'
COLLECTED BY: Client

PROPERTIES:

pH (measured) = 7.1
Resistivity (Ohm.M @ 25°C) = 0.92
Electrical Conductivity (µS/cm @ 25°C) = 10860
Specific Gravity (S.G. @ 20°C) = na
Measured Total Dissolved Solids(Evap@180°C) mg/L = na
Measured Total Suspended Solids mg/L = na

CHEMICAL COMPOSITION

CATIONS		**mg/L**	**meq/L**	**ANIONS**		**mg/L**	**meq/L**
Ammonium	as NH_4	na	na	Bromide	as Br	na	na
Potassium	as K	341	8.72	Chloride	as Cl	3400	95.77
Sodium	as Na	2540	110.48	Fluoride	as F	na	na
Barium	as Ba	na	na	Hydroxide	as OH	nd	nd
Calcium	as Ca	120	6.45	Nitrite	as NO_2	na	na
Iron	as Fe	na	na	Nitrate	as NO_3	nd	nd
Magnesium	as Mg	1	0.08	Sulphide	as S	na	na
Strontium	as Sr	na	na	Bicarbonate	as HCO_3	1268	20.79
Boron	as B	na	na	Carbonate	as CO_3	nd	nd
				Sulphite	as SO_3	na	na
				Sulphate	as SO_4	110	2.29
Total Cations		3002	125.73	**Total Anions**		4778	118.85

DERIVED PARAMETERS

a) Ion Balance (Diff*100/Sum) (%) = 2.81
b) Total Alkalinity (calc as $CaCO_3$) (mg/L) = 1037
c) Total of Cations + Anions = 7780
(measured dissolved salts)
d) Hardness (calc as $CaCO_3$) (mg/L) = 304

d) Theoretical Total dissolved salts = 6950
(From Electrical Conductivity)

QUALITY CONTROL COMMENTS

Item	Actual Value	Acceptance Criteria	Satisfactory? (Yes/No)
Ion Balance (%) =	2.81	5%	Yes
Expected pH range		< 8.3	Yes
% difference between measured total dissolved solids and calc total dissolved salts (from ionic comp) =	na	5%	na

na = not analysed
nd = not detected
is = insufficent sample

If No - what action is recommended by Amdel

Appendix 4 – Hutton Water Analysis

Inland-1

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Water Analysis Report   Job No. LQ3157   Method WAT 2

Sample ID. Inland-1, DST-1

Chemical Composition		mg/L	me/L
Cations			
Calcium	(Ca)	406.0	20.26
Magnesium	(Mg)	62.0	5.10
Sodium	(Na)	4640.0	201.83
Potassium	(K)	9720.0	248.59
Anions			
Hydroxide	(OH)		
Carbonate	(CO3)		
Bi-Carbonate	(HCO3)	43.7	0.72
Sulphate	(SO4)	3260.0	67.88
Chloride	(Cl)	14244	401.24
Nitrate	(NO3)	56.0	0.90
Bromide	(Br)	192.0	
Other Analyses			
Reaction - pH			7.1
Conductivity (E.C.) (micro -S/cm at 25 degC)			55600
Resistivity (Ohm.M at 25 degC)			0.18

Derived Data	mg/L
Total Dissolved Solids	
A. Based on E.C.	35584
B. Calculated (HCO3=CO3)	32410
Total Hardness	1269
Carbonate Hardness	35
Non-Carbonate Hardness	1233
Total Alkalinity	35
(Each as CaCO3)	

Totals and Balance

Cations (me/L)	475.8	Diff=	5.05
Anions (me/L)	470.7	Sum =	946.52

ION BALANCE (Diff*100/Sum) = 0.53%

Sodium / Total Cation Ratio 42.4%

Remarks

Note: mg/L = Milligrams per litre
me/L = MilliEqivs.per litre

Name: Owen Nugent
Address: IOR Exploration
39 Bulima Street Bulimba
Brisbane QLD 4171

Date Collected UNKNOWN
Date Received 26/07/94
Collected by CLIENT

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Water Analysis Report Job No. LQ3983 Method WAT 2
Page 2

Sample ID. INLAND 2 DST-1

Chemical Composition

		mg/L	me/L
Cations			
Calcium	(Ca)	270.0	13.47
Magnesium	(Mg)	22.0	1.81
Sodium	(Na)	3780.0	164.42
Potassium	(K)	7520.0	192.33
Anions			
Hydroxide	(OH)		
Carbonate	(CO3)		
Bi-Carbonate	(HCO3	40.5	0.66
Sulphate	(SO4)	987.0	20.55
Chloride	(Cl)	12154	342.37
Nitrate	(NO3)	<0.1	

Other Analyses :

Reaction - pH	4.7
Conductivity (E.C) (micro -S/cm at 25°C)	36200
Resistivity Ohm.M at 25°C	0.28

Derived Data

	mg/L
Total Dissolved Solids	
A. Based on E.C.	23168
B. Calculated (HCO3=CO3)	24753
Total Hardness	765
Carbonate Hardness	32
Non-Carbonate Hardness	733
Total Alkalinity	32
(Each as CaCO3)	

Totals and Balance

Cations (me/L)	372.0	Diff=	8.45
Anions (me/L)	363.6	Sum =	735.6

ION BALANCE (Diff*100/Sum) = 1.15%

Sodium / Total Cation Ratio 44.2%

mg/L = Milligrams per litre
me/L = MilliEqivs.per litre

Name:	OWEN NUGENT	Formation	
Address:	IOR EXPLORATION	Type	
	9 YARRUM GROVE	Point	SAMPLE CHAMBER
	SOMERTON PARK 5044	Time	
		Interval	5730-5750
Date Collected	UNKNOWN	Geologist	
Date Received	19/06/95	Depth	
Collected by	CLIENT		

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Water Analysis Report   Job No. LQ4016   Method WAT 2
Page 1

Sample ID. INLAND 3 DST-2 2 OF 4

Chemical Composition		mg/L	me/L
Cations			
Calcium	(Ca)	39.0	1.95
Magnesium	(Mg)	<0.1	
Sodium	(Na)	1645.0	71.55
Potassium	(K)	135.0	3.45
Anions			
Hydroxide	(OH)		
Carbonate	(CO3)		
Bi-Carbonate	(HCO3	1298.6	21.29
Sulphate	(SO4)	870.0	18.11
Chloride	(Cl)	1337	37.67
Nitrate	(NO3)	6.5	0.10

Other Analyses :

Reaction - pH	6.6
Conductivity (E.C) (micro -S/cm at 25°C)	5800
Resistivity Ohm.M at 25°C	1.72

Derived Data	mg/L
Total Dissolved Solids	
A. Based on E.C.	3712
B. Calculated (HCO3=CO3)	4682
Total Hardness	97
Carbonate Hardness	97
Non-Carbonate Hardness	
Total Alkalinity	1041
(Each as CaCO3)	

Totals and Balance

Cations (me/L)	77.0	Diff=	0.22
Anions (me/L)	77.2	Sum =	154.1

ION BALANCE (Diff*100/Sum) = 0.15%

Sodium / Total Cation Ratio 93.0%

mg/L = Milligrams per litre
me/L = MilliEqivs.per litre

Name:	OWEN NUGENT	Formation	HUTTON SST
Address:	IOR EXPLORATION	Type	RECOVERED WATER
	9 YARRUM GROVE	Point	DRILL COLLARS
	SOMERTON PARK 5044	Time	
		Interval	5306-5326
Date Collected	19/06/95	Geologist	T.BAILY
Date Received	03/07/95	Depth	
Collected by	T.BAILY		

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TABLE 1 - WATER ANALYSIS

JOB NUMBER: LQ11962

WELL / ID: Inland North East # 1
SAMPLE TYPE: Water
SAMPLE POINT: Manifold
DATE COLLECTED: 08/04/02
DATE RECEIVED: 23/08/02

FORMATION: Hutton SST
INTERVAL: 5245'-5258(L)
COLLECTED BY:

PROPERTIES:

pH (measured) = 7.0
Resistivity (Ohm.M @ 25°C) = 1.64
Electrical Conductivity (µS/cm @ 25°C) = 6110
Specific Gravity (S.G. @ 20°C) = na
Measured Total Dissolved Solids(Evap@180°C) mg/L = na
Measured Total Suspended Solids mg/L = na

CHEMICAL COMPOSITION

CATIONS		mg/L	meq/L
Ammonium	as NH_4	na	na
Potassium	as K	166	4.25
Sodium	as Na	1309	56.94
Barium	as Ba	na	na
Calcium	as Ca	32	1.60
Iron	as Fe	na	na
Magnesium	as Mg	3	0.25
Strontium	as Sr	na	na
Boron	as B	na	na
Total Cations		1510	63.03

ANIONS		mg/L	meq/L
Bromide	as Br	na	na
Chloride	as Cl	1201	33.83
Fluoride	as F	na	na
Hydroxide	as OH	nd	nd
Nitrite	as NO_2	na	na
Nitrate	as NO_3	nd	nd
Sulphide	as S	na	na
Bicarbonate	as HCO_3	1991	32.64
Carbonate	as CO_3	nd	nd
Sulphite	as SO_3	na	na
Sulphate	as SO_4	15	0.31
Total Anions		3207	66.78

DERIVED PARAMETERS

a) Ion Balance (Diff*100/Sum) (%) = 2.89
b) Total Alkalinity (calc as $CaCO_3$) (mg/L) = 1632
c) Total of Cations + Anions = 4717
(calculated dissolved salts)
d) Hardness (calc as $CaCO_3$) (mg/L) = 92

e) Theoretical Total dissolved salts = 3910
(From Electrical Conductivity)

QUALITY CONTROL COMMENTS

Item	Actual Value	Acceptance Criteria	Satisfactory? (Yes/No)
Ion Balance (%) =	2.89	5%	Yes
Undetected ions % = (from comparison of calculated vs theoretical salts derived from measured conductivity)	-20.63	10%	Yes
Expected pH range		< 8.3	Yes
% difference between measured total dissolved solids and calc total dissolved salts (from ionic comp) =	na	5%	na

na = not analysed
nd = not detected
is = insufficent sample

If No - what action is recommended by Amdel