Australian Government
Department of the Environment and Energy
Geoscience Australia

BIOREGIONAL ASSESSMENTS

Rapid regional prioritisation for tight and shale gas potential of eastern and northern Australian basins

Geological and Bioregional Assessment Program: Stage 1 Appendices

June 2018

A scientific collaboration between the Department of the Environment and Energy and Geoscience Australia

The Geological and Bioregional Assessments Program

The Geological and Bioregional Assessments Program is a series of independent scientific studies investigating both the shale and tight gas prospectivity of key onshore eastern and northern Australian basins and the potential impacts on water and the environment from their development. The program is managed by the Australian Government Department of the Environment and Energy. For more information, visit http://www.bioregionalassessments.gov.au.

Department of the Environment and Energy

The Department designs and implements Australian Government policy and programs to protect and conserve the environment, water and heritage, promote climate action, and provide adequate, reliable and affordable energy. For more information visit http://www.environment.gov.au.

Geoscience Australia

Geoscience Australia is Australia's national geoscience agency and exists to apply geoscience to Australia's most important challenges. Geoscience Australia provides geoscientific advice and information to the Australian Government to support current priorities. These include contributing to responsible resource development; cleaner and low emission energy technologies; community safety; and improving marine planning and protection. The outcome of Geoscience Australia's work is an enhanced potential for the Australian community to obtain economic, social and environmental benefits through the application of first class research and information. For more information, visit http://www.ga.gov.au.

ISBN: 978-1-921069-14-7

Citation

Hall LS, Buchanan S, Totterdell JM, Lai ÉCS, Langford RP, Sundaram B, Ransley TR, Glenn KC, Heugh A, Inskeep C, Zhu R, Lech, M, Skeers N and Stewart G (2018) Rapid regional prioritisation for tight and shale gas potential of eastern and northern Australian basins. Geological and Bioregional Assessments Program: Stage 1. Prepared by Geoscience Australia for the Department of the Environment and Energy, Australia.

Authorship is listed in relative order of contribution.

Copyright

Disclaimer

Cover photograph

Coongie Lakes, by Paul Wainwright and the Department of the Environment and Energy.

Contents

Figures

Tables

Appendix A Shale and tight gas exploration activity in eastern and northern Australia

A.1 Introduction

In order to identify all shale and/or tight gas plays with the potential to supply gas to either the east coast or Northern Territory gas markets, a comprehensive review of shale and tight gas exploration activity was conducted for all eastern and northern Australian basins. In addition, all public domain tight and shale gas resource information current to 2017 were compiled by play type.

This information was used to determine the initial shortlist of basins most likely to be capable of supplying significant volumes of tight and/or shale gas to the East Coast Gas Market in the next five to ten years. Those areas where unconventional shale and tight gas exploitation is currently occurring – or is likely to occur in the near future – were considered priority areas for research.

The data underpinning this review is all public domain and key sources include:

- federal government reports and websites (e.g. AERA, 2018; UPR, 2015, 2016);
- state and territory governments reports and websites (e.g. DNRM, 2017; DPCSA, 2017; Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018);
- 3rd party reviews (e.g. EIA, 2013; AWT International, 2013), and;
- industry intelligence sourced from company websites, ASX media releases and other news articles.

A.2 Classification and assessment of petroleum resources

To provide context for the analysis conducted in this appendix, the following section provides back ground information on the following themes:

- the petroleum resource classification scheme;
- resource assessment methodologies for unconventional resources, and;
- classification of exploration status.

This text within this section has been modified from AERA (2018).

A.2.1 Petroleum resource classification scheme

The petroleum industry in Australia uses the Petroleum Resources Management System (PRMS, 2007) for classification of oil and gas resources registered on the ASX (ASX, 2014; RISC, 2013). The description below is a summary of the PRMS (2007) and an overview published by the Society of Petroleum Engineers (SPE, 2007).

Oil and gas reserves and resources are defined as volumes that will be commercially recovered in the future. Unlike the inventory of a manufacturing company, reserves are physically located in reservoirs deep underground and cannot be visually inspected or counted, but rather are estimates based on the evaluation of data related to the amount of oil and gas present. There is no definitive answer until the end of a reservoir's producing life. All reserve estimates involve some degree of uncertainty. The estimation of reserves volumes is generally performed by highly-skilled individuals who use their experience and professional judgment in the calculation of these volumes.

To take into account this uncertainty, the PRMS incorporates a central framework that categorises reserves and resources according to the level of certainty associated with their recoverable volumes (horizontal axis), and classifies them according to the potential for reaching commercial producing status (vertical axis).

A graphical representation of the PRMS classification scheme is shown in Figure A.1.

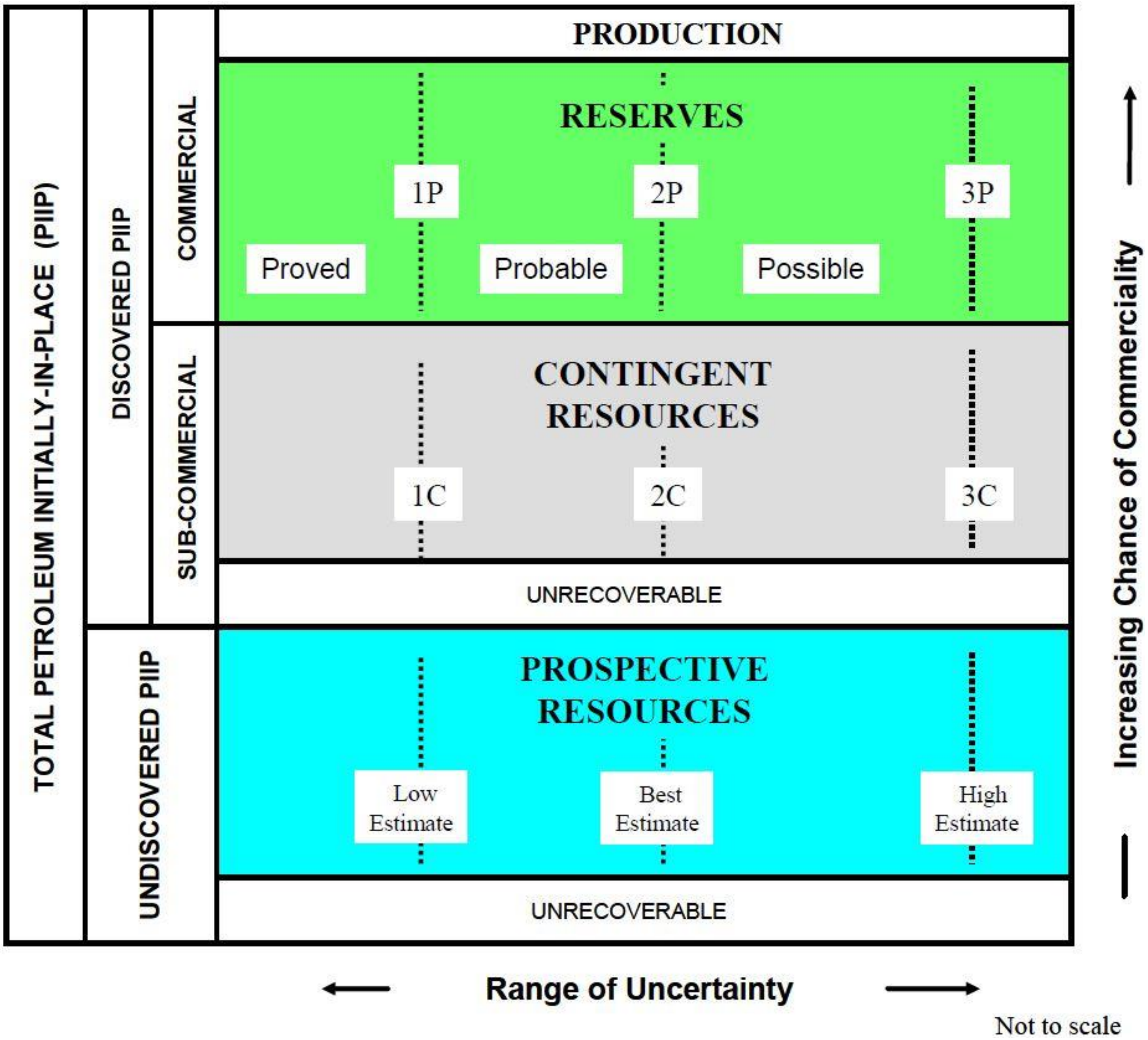

Figure A.1 Graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum (PRMS, 2007). The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality", that is, the chance that the project that will be developed and reach commercial producing status.

A.2.1.1 Differences in classes (vertical axis)

The four major recoverable resources classes defined by the PRMS are production, reserves, contingent resources, and prospective resources. There is also a distinct class for unrecoverable petroleum. These classes are shown on the vertical axis of the PRMS framework (Figure A.1).

Production is the cumulative quantity of oil and natural gas that has been recovered already (by a specified date). This is primarily output from operations that has already been produced.

Reserves represent discovered resources that are commercially recoverable and economical for development.

Contingent resources represent discovered resources that are potentially recoverable but not yet considered mature enough for commercial development. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. For example, all required internal and external approvals should be in place or determined to be forthcoming, including environmental and governmental approvals. There must also be evidence of firm intention by a company to proceed with development within a reasonable time frame (typically 5 years, though it could be longer).

Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable on the basis of indirect evidence but have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be evaluated and an estimate of recoverable quantities prepared. Prospective resource can also be converted directly to reserve if it is proved that it can be developed commercially after drilling and testing.

Some petroleum will be classified as "unrecoverable" at this point in time. These are not producible by any projects that the company may plan or foresee. While a portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur, some of the remaining portion may never be recovered due to physical or chemical constraints in the reservoir. The volumes classified using this system represent the analysis of the day, and should be regularly reviewed and updated, as necessary, to reflect changing conditions.

A project may have recoverable quantities in several resource classes simultaneously. As barriers to development are removed, some resources may move to a higher classification. One of the primary distinctions between resources and reserves is that while resources are technically recoverable, they may not be commercially viable. Reserves are commercially viable and there is intent to develop them.

A.2.1.2 Differences in categories (horizontal axis)

Within any resource class other than production, volumes are placed into different categories based on their certainty of eventually coming out of the ground. Decisions to upgrade volumes to any category within a class are generally based on the technical certainty of volume recovery. In this discussion, the focus is on the reserve class, as these volumes are commonly the focus of public discussions regarding oil and gas company producing assets.

The highest valued category of reserves is "**proved**" reserves. Proved reserves have a reasonable certainty of being recovered, which means a high degree of confidence that the volumes will be recovered. To be clear, reserves must have all commercial aspects addressed. It is technical issues which separate proved from unproved categories.

"**Probable**" or "**possible**" reserves are lower categories of reserves, commonly combined and referred to as "unproved reserves," with decreasing levels of technical certainty. Probable reserves are volumes that are defined as "less likely to be recovered than proved, but more certain to be recovered than Possible Reserves". Possible reserves are reserves which geological and engineering data suggests are less likely to be recoverable than probable reserves.

The term 1P is frequently used to denote proved reserves, 2P is the sum of proved and probable reserves and 3P the sum of proved, probable and possible reserves. The best estimate of recovery from committed projects is generally considered to be the 2P sum of proved and probable reserves. Note that these volumes only refer to projects that are currently justified for or already in development. Total value of any resource base must include an assessment of the contingent and prospective resources as well as reserves.

In order for volumes to move from one category to the next, the technical issues which cause them to be placed in less certain categories must be resolved. In the majority of cases, this requires that additional data must be obtained before any greater certainty can be recognised. This may include, among other things, the drilling of additional wells, the monitoring of current production to better understand performance or the implementation of a pilot to have greater confidence in the volumes that full scale development projects may eventually produce.

A.2.2 Unconventional resource assessment methods

There are three main classes of resource assessments – generative, gas- or oil-in-place and estimated ultimate recovery (EUR).

- Generative assessments assess the ability of a petroleum system to generate petroleum.
- Gas- or oil-in-place assessments calculate the concentration of petroleum in the reservoir at the present day.
- Estimated ultimate recovery assessments use petroleum production data and reservoir simulation models to forecast future production potential from the reservoir assuming a given set of parameters. EUR assessments can only be used for reservoirs with existing production, as they rely heavily on the known production characteristics of the reservoirs.

For all three of these methods, it is possible to use a probabilistic assessment approach, defining parameters within the assessment as probability distributions in order to provide a statistically based range of possible outcomes. Probabilistic assessment reports typically give a low estimate (P90: 90% probability that at least this much oil or gas can be found in place), a middle estimate (P50: 50% chance of occurrence), and a high estimate (P10: only a 10% chance that this volume of oil or gas will be found or exceeded).

An estimated *recoverable* volume is calculated by applying a recovery factor to the assessed volume of oil or gas. The recovery factor is intended to reflect risks in exploration (e.g. the need to find ‘sweet spots’, data quality), risks in development (e.g. optimising drilling and hydraulic stimulation to the local stress regime for mobilisation of oil and gas), as well as other factors impacting development (e.g. government policy, uncertainties in project approvals, finance and infrastructure). In geologically well understood reservoirs with known production characteristics, and where current technology is able to recover a high percentage of oil and gas from the reservoir, recovery factors for unconventional gas resources can be as high as 30%, and for shale oil between 2–7% (EIA, 2013).

As the contingent resource numbers are independently assessed to strict guidelines, they are relatively reliable.

Uncertainties in prospective resource numbers are much greater. In addition to the inherent uncertainty in the numbers, the following factors need to be considered when interpreting this data.

- The area covered by each assessment varies. Company numbers are reported for individual permits. In contrast independent assessments (for examples those by federal, state or territory government or independent assessors) have been conducted regionally to capture the entire play area.
- Assessment methodologies differ and the data underpinning them may vary considerably in terms of amount, type and quality (as discussed above).
- Recovery factors are very poorly defined, especially for shale and tight gas plays.

These inconsistencies affect how resources are estimated and reported. As a result the relative prospectivity of basins cannot always be ranked directly based on contingent and prospective resource numbers alone. Further information on basin geology, petroleum systems and potential plays is required to more effectively evaluate basin prospectivity.

A.2.3 Classification of exploration status

The exploration status of each identified shale and/or tight gas play may be evaluated based on phase of development and project maturity following the PRMS scheme (Figure A.2; PRMS, 2007), taking into consideration uncertainties in resource numbers described above.

Data used in this study to informally evaluate development phase, and hence exploration status, by play type at a basin level are listed below (see also Table A.1):

- a list of key wells targeting each plays, although it should be noted that this list is not exhaustive, as there are inconsistencies between how wells have been classified depending on the information source, and;
- the type of resource data (e.g. contingent or prospective) available for the play, if any, along with the associated uncertainties.

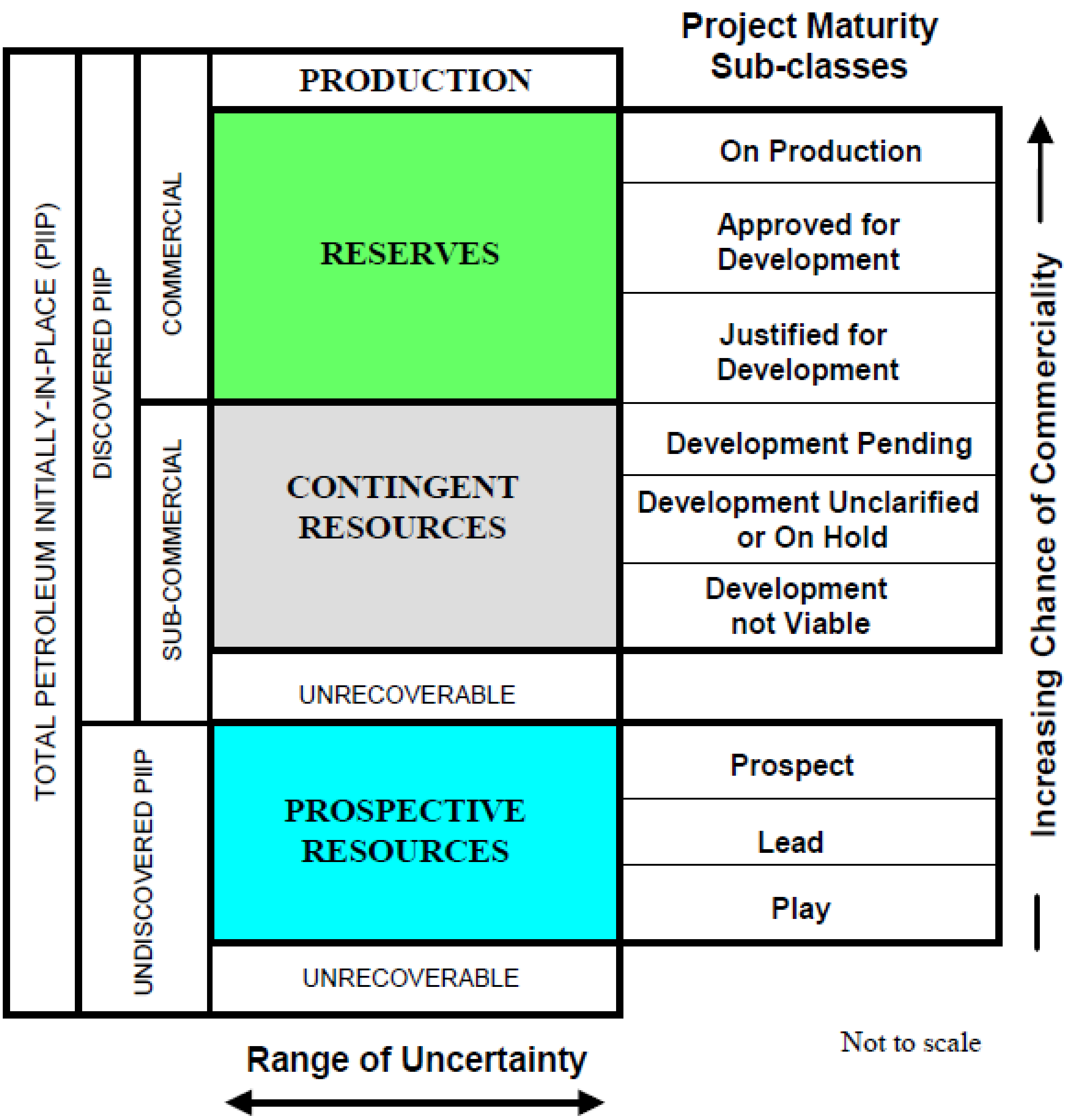

Figure A.2 Classification of development stages based on project maturity (PRMS, 2007).

Table A.1 Metrics used to assign exploration status in terms of development phases.

Phase of development	Project maturity	Probable level of drilling activity	Resources
No exploration activity	no active investigation/ regional desk top studies	no well drilled	
Preliminary exploration	investigation at play level	initial drilling but no discovery	?prospective resources
Exploration	investigation at prospect level	discovery well	?prospective resources
Early appraisal	discovery but development not viable	multiple wells	contingent resources
Appraisal	discovery mature for development decision	multiple wells	contingent resources
Development	committed for or under development	multiple wells	reserves

A.3 Shale and tight gas exploration activity analysis results

A comprehensive review of shale and tight gas exploration activity was conducted for all eastern and northern Australian basins, in order to identify all shale and/or tight gas plays with the potential to supply gas to either the east coast or Northern Territory gas markets. This material provided the foundation on which the nine short listed basins were chosen.

The results of the industry activity review are summarised in Figure A.3 and Table A.2. This analysis shows that:

- a total of 27 eastern and northern Australian basins contain possible tight and/or shale gas plays;
- four basins are in the appraisal phase (Cooper, Gippsland and McArthur basins and the Isa Superbasin), and;
- exploration is underway to varying extents in a further 5 basins (Amadeus, Bowen, Clarence-Moreton, Georgina and Otway basins).

Note preliminary exploration for shale gas has occurred in the Eromanga Basin, however this activity has now ceased due to poorer than expected results and the exploration status is currently considered to be inactive.

All available public domain tight and shale gas resource information current to 2017 were compiled by play type, for all eastern and northern Australian basins. Although no reserves are currently booked for shale and/or tight gas plays, Table A.3 lists all published contingent and potentially recoverable gas-in-place resource numbers, along with the area covered by each assessment. Results show that:

- a total of 17.1 Tcf of contingent shale and tight gas resources have been reported from four basins (Cooper, Gippsland, McArthur basins and the Isa Superbasin), and;
- a total of 393.3 Tcf of potentially recoverable shale and tight gas-in-place resources have been reported from 12 basins.

Note for some plays, multiple prospective resource estimates are available. To avoid double counting of resource numbers, Geoscience Australia has included the prospective resource number judged to be the best quality, based on the currency and rigour of the resource assessment.

In the Cooper Basin, where it is common to drill a vertical well and produce from multiple intervals, contingent resource numbers do not separate out between shale and tight gas. As a result, no attempt was made to separate resource numbers from shale versus tight gas plays.

Several reported resource numbers have also been excluded from the analysis, as follows.

- Contingent resources of 0.14 Tcf (157 PJ) have recently been estimated sandstones in the Albany structure in the Galilee Basin (Comet Ridge, 2017). However based on the public information available, it unclear what proportion of this (if any) represents tight gas, rather than conventional, so this contingent resource number is excluded from the analysis at this point.

- The prospective recoverable resource estimate of 82 Tcf for the Toolebuc Formation shale gas play by AWT International (2013) has not been included, as this large resource size is inconsistent with poorer than expected exploration results (Exoma Energy, 2012; DNMR, 2017).

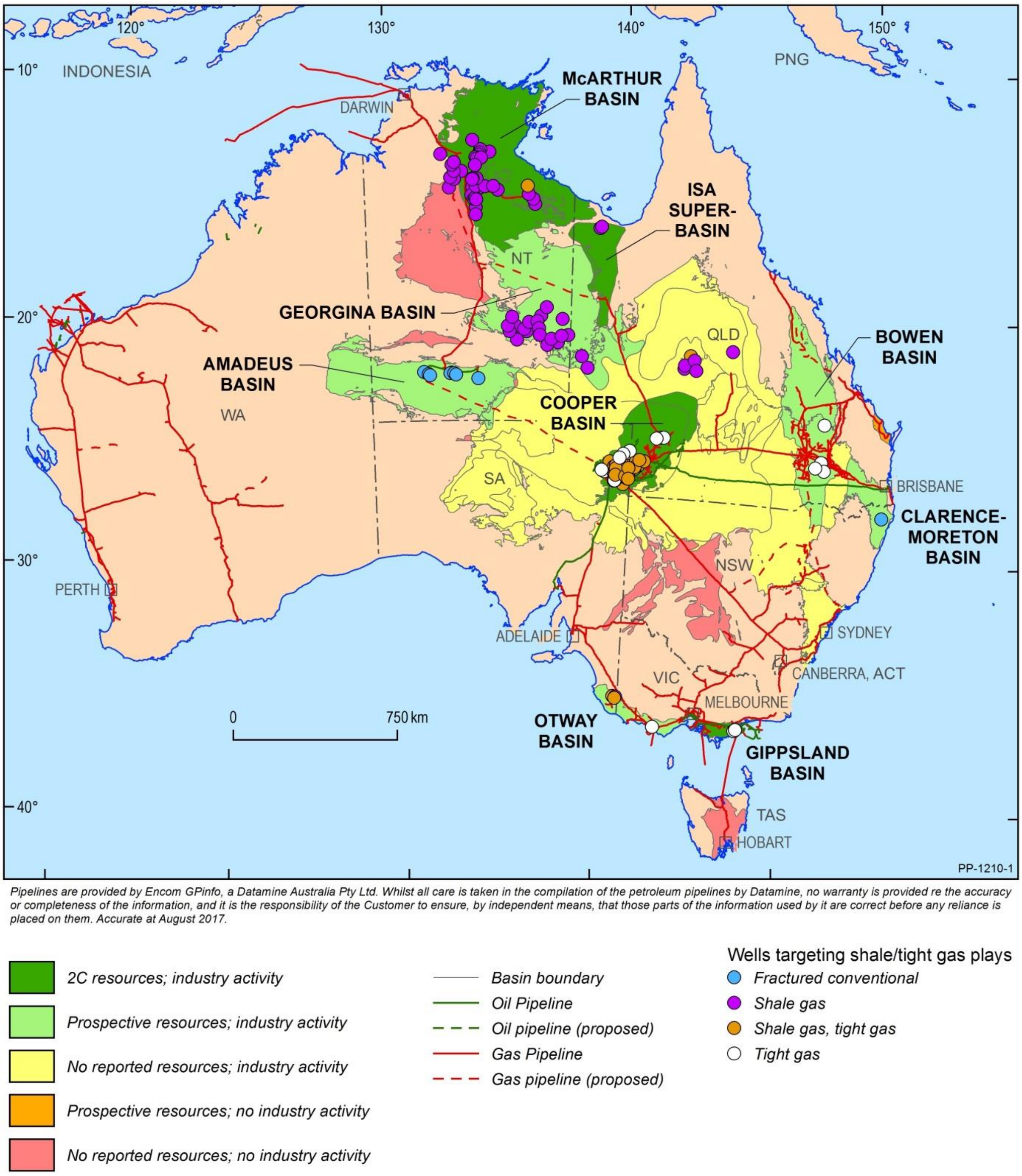

Figure A.3 Australian basins classified by level of exploration activity for shale/ tight gas. Labelled sedimentary basins are those with reported contingent (2C) or prospective resources and on-going industry activity (as permitted by current regulatory environments). Basin outlines are sourced from Stewart et al. (2013), with the exception of the Isa Superbasin, which has been estimated from DNRM (2017). Oil and gas pipelines from GA (2015a). Key wells targeting shale and/or tight gas plays are also shown. Note that this well coverage is not exhaustive, as there are inconsistencies between how wells have been classified depending on the information source.

Table A.2 Summary of shale and/or tight gas plays in eastern and northern Australian basins, along with associated exploration activity.

Basin	State/ Territory	Tight gas plays	Shale gas plays	Key wells targeting shale/ tight gas plays	Shale/ tight gas exploration status	Key References
Adavale Basin	QLD	Log Creek Formation; Lissoy Sandstone; Cooladdi Dolomite	Log Creek Formation; Lissoy Sandstone; Cooladdi Dolomite	None	No shale/ tight gas exploration activity.	Draper et al. (2004); Jell (2013): DNMR (2017)
Amadeus Basin	NT	Pacoota Sandstone; Stairway Sandstone	Horn Valley Siltstone	>34 wells fracture stimulated tight gas reservoir within conventional fields	Production of gas from tight sands around conventional fields but no tight gas reserves or production data reported. Preliminary exploration for tight/shale gas.	DSWPET (2011a); Vu et al. (2011); Warner (2012); AWT International (2013); Munson (2014); Central Petroleum (2017); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)
Arckaringa Basin	SA	None	Stuart Range Formation (biogenic gas only)	None	No shale/ tight gas exploration activity. (Preliminary exploration for shale oil only.)	Goldstein et al. (2012); Linc Energy (2017)
Bowen Basin	QLD	Showgrounds Sandstone; Rewan Formation (lower); Bandanna Formation; Tinowon Formation	Bandanna Formation; Black Alley Shale	~6 wells targeting tight gas	Exploration for tight gas (Taroom Trough). Preliminary exploration for shale gas.	AWT International (2013); Jell (2013); Hayes et al (2016); Nicholls et al. (2015); DNMR (2017)
Clarence-Moreton Basin	QLD, NSW	Koukandowie Formation; Raceview Formation; Gatton Sandstone	Koukandowie Formation; Raceview Formation	1 well fracture stimulated tight gas reservoir within conventional field	Preliminary exploration for tight gas. No shale gas exploration activity.	Wells and O'Brien (1994); AWT International (2013); Jell (2013); O'Neill and Danis (2013); Metgasco (2011, 2013); Ward and Kelly (2013)
Cooper Basin	SA, QLD	Toolachee Formation; Daralingie Formation; Epsilon Formation; Patchawarra Formation	Toolachee Formation; Roseneath Shale; Murteree Shale; Patchawarra Formation	>40 wells drilled testing shale and tight gas plays	Appraisal for shale and tight gas (2C resources booked for multiple shale and tight gas plays). Minor, past production from shale/ tight gas wells.	Santos (2010); AWT International (2013); Goldstein et al. (2012); Jell (2013); DNMR (2017); DPCSA (2017)
Darling Basin	NSW	yes	yes	None	No shale/ tight gas exploration activity.	UPR (2015, 2016); Resources and Energy, New South Wales (2017a)

Basin	State/ Territory	Tight gas plays	Shale gas plays	Key wells targeting shale/ tight gas plays	Shale/ tight gas exploration status	Key References
Eromanga Basin	NT,SA,QLD	Adori Sandstone	Toolebuc Formation; Birkhead Formation; Westbourne Formation; Poolowanna Formation	> 8 wells drilled targeting shale gas potential in the Toolebuc Formation	No current shale/ tight exploration activity. Note initial preliminary exploration focused on Toolebuc Formation shale gas potential has currently ceased due to poorer than expected results.	AWT International (2013); DNMR (2017); Exoma Energy (2012); Jell (2013); Munson (2014)
Galilee Basin	QLD	Lake Galilee Sandstone	Betts Creek Beds; Aramac Coal Measures	None	No shale/ tight gas exploration activity.	Exoma Energy (2012); Hawkins and Green (1993); Jell (2013); Comet Ridge (2017a); DNMR (2017)
Georgina Basin	NT, QLD	Arrinthrunga Formation; Georgina Limestone; Arthur Creek Formation; Inca Shale; Beetle Creek Formation; Thorntonia Limestone / Hay River Formation	Arrinthrunga Formation; Georgina Limestone; Arthur Creek Formation; Inca Shale; Beetle Creek Formation; Thorntonia Limestone / Hay River Formation	>22 wells targeting shale/ tight gas	Exploration for shale and tight gas.	DSWPET (2011b); Petrofrontier (2011); Vu et al. (2011); AWT International (2013); Jell (2013); Munson (2014); DNMR (2017); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018);
Gippsland Basin	VIC	Lakes Entrance Formation; Strzelecki Group	Strzelecki Group	>$$ wells targeting tight gas	Appraisal (2C tight gas resources booked for Wombat &Trifon-Gangell fields). No shale gas exploration activity.	Goldie Divko (2015); GA (2017a); Lakes Oil (2017)
Gunnedah Basin	NSW	Black Jack Formation; Maules Creek Formation	Black Jack Formation; Maules Creek Formation; Watermark Formation	None	No shale/ tight gas exploration activity. CSG (e.g. Narrabri Gas project) and conventional exploration only.	AWT International (2013); O'Neill and Danis (2013); Comet Ridge (2017b); Santos (2017)
Isa Superbasin	QLD, NT	None	Lawn Hill Shale; Termite Range Formation; Riversleigh Siltstone	~2 wells targeting shale gas	Early appraisal for shale gas (2C resources booked for the Lawn Hill Shale and Riversleigh Siltstone).	DNMR (2017); Jell (2013); Munson (2014); Armour Energy (2017a); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)
Laura Basin	QLD	Dalrymple Sandstone	Dalrymple Sandstone	None	No shale/ tight gas exploration activity.	Hawkins and Williams (1990); Jell (2013); DNMR (2017)

Basin	State/ Territory	Tight gas plays	Shale gas plays	Key wells targeting shale/ tight gas plays	Shale/ tight gas exploration status	Key References
Maryborough Basin	QLD	Maryborough Formation	Maryborough Formation (including the Goodwood and Cherwell mudstone members); Tiaro Coal Measures	None	No shale/ tight gas exploration activity.	AWT International (2013); Blue Energy (2013); Jell (2013); DNMR (2017)
McArthur Basin (including the Beetaloo Sub-basin)	NT	Bessie Creek Sandstone; Moroak Sandstone; Reward Dolostone (fractured reservoir)	Kyalla Formation; Velkerri Formation; ?Vaughn Siltstone; Yalco Formation; Lynott Formation; Barney Creek Formation	~35 wells targeting shale gas	Early appraisal for shale gas (2C resources booked for the Velkerri Formation)	Armour Energy (2017b); AWT International (2013); Munson (2014); Close et al. (2017); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018); Revie (2017a,b)
Ngalia Basin	NT	Mount Eclipse Sandstone		None	No shale/ tight gas exploration activity.	Munson (2014); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)
Oaklands Basin	NSW	?Coorabin Coal Measures; ?Jerilderie sandstone	?Coorabin Coal Measures ; ?Urana Formation	None	No shale/ tight gas exploration activity.	O'Neill and Danis (2013); UPR (2015, 2016); Resources and Energy, New South Wales (2017a)
Otway Basin	SA, VIC	Eumeralla Formation	Crayfish Sub-group; Casterton Formation	3 wells targeting tight gas	Exploration underway for tight gas.	Goldstein et al. (2012); AWT International (2013); Goldie Divko (2015); GA (2017b)
Pedirka Basin	NT,SA	Purni Formation	Purni Formation	None	No shale/ tight gas exploration activity.	AWT International (2013); Munson (2014); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)
South Nicholson Basin	NT, QLD	Constance Sandstone	None	None	No shale/ tight gas exploration activity	Jell (2013); Munson (2014)
Surat Basin	NSW, QLD	None	Walloon Coal Measures	None	No shale/ tight gas exploration activity. (Note some wells targeting tight gas in the underlying Bowen Basin have been incorrectly reported to be associated with the Surat Basin).	Jell (2013): DNMR (2017);

Basin	State/ Territory	Tight gas plays	Shale gas plays	Key wells targeting shale/ tight gas plays	Shale/ tight gas exploration status	Key References
Sydney Basin	NSW	Narrabeen Group; Illawarra Coal Measures; Shoalhaven Group	None	None	No shale/ tight gas exploration activity.	AGL (2017); O'Neill and Danis (2013); Ward and Kelly (2013)
Tasmania Basin	TAS	Woody Island Formation	Woody Island Formation	None	No shale/ tight gas exploration activity.	Bacon et al. (2000)
Warburton Basin	NT, SA, QLD	Pando Formation; Dullingari Group; Kalladeina Formation	Dullingari Group	None	No shale/ tight gas exploration activity.	Goldstein et al. (2012); Jell (2013); Munson (2014)
Wiso Basin	NT	Montejinni Limestone	Montejinni Limestone	None	No shale/ tight gas exploration activity.	Central Petroleum (2011); Munson (2014); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)

Table A.3 Best available estimate of shale and tight gas contingent and potentially recoverable prospective resources (Tcf) of eastern and northern Australian onshore basin. The data presented here underpinned the decision on which basins to include in the basin short list. Please refer to the source references for further details on assessment area, methodology and associated uncertainties.

Basin	State/ Territory	Assessment area	Operator	Contingent resources (Tcf)			Potentially recoverable prospective resources (Tcf)			Play type	Reservoir	Source
				1C	2C	3C	Low	Best	High			
Amadeus Basin	NT	Regional; 3,440 km^2		-	-	-	-	9.8	-	Tight gas	Pacoota Sandstone	CORE (2017); DWSPET (2011)
Amadeus Basin	NT	Regional; 7,395 km^2		-	-	-	-	11.3	-	Shale gas	Horn Valley Siltstone	CORE (2017); DWSPET (2011)
Amadeus Basin	NT	Regional; 3,440 km^2		-	-	-	-	5.1	-	Tight gas	Stairway Sandstone	CORE (2017); DWSPET (2011)
Bowen Basin	QLD	Regional; 51,252 km^2		-	-	-	-	97	-	Shale gas	Black Alley Shale	AWT International (2013)
Clarence-Moreton Basin	NSW	Regional; 4,407 km^2		-	-	-	-	11	-	Shale gas	Koukandowie Formation	AWT International (2013)
Clarence-Moreton Basin	NSW	Regional; 4,407 km^2		-	-	-	-	10	-	Shale gas	Raceview Formation	AWT International (2013)
Cooper Basin	QLD	ATP 855 (Nappamerri Trough)	Beach	0.34	1.57	5.84	-	-	-	Shale gas, tight gas	Various	Beach Energy (2015)
Cooper Basin	SA	PRLs 33 to 49 (Nappamerri Trough)	Beach	0.95	1.95	3.9	-	-	-	Shale gas, tight gas	Various	Beach Energy (2015)
Cooper Basin	QLD	ATP 940 (100%)	Drillsearch	0.22	0.77	1.85	-	-	-	Shale gas, tight gas	At Charal-1 and Anakin-1	Drillsearch (2015)
Cooper Basin	SA	CBJV (PPLs 7, 8, 9, 11, 101, 102, 113)	Santos	1.73	3.52	6.84				Shale gas, tight gas	Winnie 3D Shale Gas	Company
Cooper Basin	SA	PEL 115, 516	Senex	0.15	0.84	2.37	-	-	-	Tight gas	Tight sands around the Hornet field	Senex (2013)

Basin	State/ Territory	Assessment area	Operator	Contingent resources (Tcf)			Potentially recoverable prospective resources (Tcf)			Play type	Reservoir	Source
				1C	2C	3C	Low	Best	High			
Cooper Basin	SA	PEL 516 (Allunga Trough)	Senex	0.12	0.7	2.05	-	-	-	Shale gas, tight gas	Patchawarra Formation and Murterre Shale at Sasanof 1	Senex (2013)
Cooper Basin	SA	PEL 96 (southwestern Cooper Basin)	Strike	0.16	0.23	0.34	-	-	-	Tight gas, coal	Patchawarra Formation coals at Le Chiffre-1 and Klebb-1	Strike Energy (2015)
Cooper Basin	QLD, SA	Regional; Patchawarra Fm - wet gas 14,426 km^2, dry gas 3,417 km^2; Epsilon Fm - wet gas 5,413 km^2, dry gas 3,401 km^2; Daralingie Fm - wet gas 4,691 km^2, dry gas 3,102 km^2; Toolachee Fm - wet gas 15,070 km^2, dry gas 2,725 km^2		-	-	-	-	50.9	-	Tight gas	Toolachee, Epsilon and Patchawarra formations	AERA (2018)
Cooper Basin	QLD, SA	Regional; Roseneath Shale - wet gas 3,834 km^2, dry gas 3,403 km^2; Murteree Shale - wet gas 3,454 km^2, dry gas 3,291 km^2		-	-	-	-	6.9	-	Shale gas	Roseneath and Murteree shales	AERA (2018)
Georgina Basin	NT, QLD	Regional; 14,433 km^2		-	-	-	-	50	-	Shale gas	Arthur Creek Formation	AWT International (2013)

Basin	State/ Territory	Assessment area	Operator	Contingent resources (Tcf)			Potentially recoverable prospective resources (Tcf)			Play type	Reservoir	Source
				1C	2C	3C	Low	Best	High			
Gippsland Basin	VIC	VIC/RRL2	Lakes Oil	0.26	0.33	0.63	-	-	-	Tight gas	Strzelecki Group - Wombat field	Lakes Oil (2010, 2017)
Gippsland Basin	VIC	VIC/PRL2	Lakes Oil	0.13	0.39	0.53	-	-	-	Tight gas	Strzelecki Group – Trifon, Gangell and North Seaspray accumulations	Lakes Oil (2009, 2017)
Gippsland Basin	VIC	Regional; 4,191 km^2	-	-	-	-	-	13.6	-	Tight gas	Strzelecki Group	GA (2017a); AERA (2018)
Gippsland Basin	VIC	Regional; 2,179 km^2	-	-	-	-	-	5.6	-	Shale gas	Strzelecki Group	GA (2017a); AERA (2018)
Gunnedah Basin	NSW	Regional; 8,631 km^2	-	-	-	-	-	13	-	Shale gas	Watermark Formation	AWT International (2013)
Isa Superbasin	QLD	ATP 1087	Armour Energy	0.03	0.15	0.36	-	-	-	Shale gas	Lawn Hill Shale at Egilabria-2 DW1	Armour Energy (2014, 2017b)
Isa Superbasin	QLD	ATP 1087	Armour Energy	-	-	-	2.7	8.1	19.6	Shale gas	Lawn Hill Shale	Armour Energy (2015)
Isa Superbasin	QLD	ATP 1087	Armour Energy	-	-	-	3.9	14	39.4	Shale gas	Riversleigh Shale	Armour Energy (2015)
Maryborough Basin	QLD	Regional; 3,264 km^2		-	-	-	-	7	-	Shale gas	Cherwell Mudstone (Maryborough Formation)	AWT International (2013)
McArthur Basin	NT	EP 171, EP 176 (Batten Trough)	Armour Energy	-	-	-	-	18.6	-	Shale gas	Barney Creek Formation	Armour Energy (2012, 2017a)
McArthur Basin	NT	EP 176 (Batten Trough)	Armour Energy	-	-	--	-	0.1	-	Shale gas, tight gas	Lynott Formation; Reward Formation	Armour Energy (2017a)

Basin	State/ Territory	Assessment area	Operator	Contingent resources (Tcf)			Potentially recoverable prospective resources (Tcf)			Play type	Reservoir	Source
				1C	2C	3C	Low	Best	High			
McArthur Basin	NT	EP76, EP98, EP117 (Beetaloo Sub-basin)	Origin Energy	-	6.6	-	-	-	-	Shale gas	B Shale member of the Velkerri Formation at Amungee NW-1H	Origin Energy (2017)
McArthur Basin	NT	Regional; area unknown		-	-	-	11.8*	20.2*	29.3*	Shale gas	middle Velkerri Formation	Revie (2017); Weatherford Laboratories (2017); *assuming a generic 10% recovery factor
Otway Basin	SA, VIC	Regional; wet gas 628 km^2; dry gas 369 km^2		-	-	-	-	1.6	-	Shale gas	Crayfish Sub-group; Eumeralla Formation; Casterton Formation	GA (2017b); AERA (2018)
Otway Basin	SA, VIC	Regional; 17,233 km^2		-	-	-	-	5.8	-	Tight gas	Casterton Formation; Eumeralla Formation	GA (2017b); AERA (2018)
Perdirka Basin	NT	Regional; area unknown		-	-	-	-	33.7	-	Shale gas	Purni Formation	NTGS (pers. Comm)
TOTAL				-	17.1	-	-	393.3	-			

References

AERA (Australian Energy Resources Assessment) (2018) Australian Energy Resources Assessment interim report, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.ga.gov.au/aera>.

AGL (2017) Camden Gas Project. Viewed 16/01/2918, <https://www.agl.com.au/about-agl/how-we-source-energy/natural-gas/natural-gas-projects/camden-gas-project>.

Armour Energy (2012) Replacement prospectus 2012. Viewed 07/08/2017, <http://www.armourenergy.com.au/assets/downloads/prospectus/armour-energy-limited-prospectus_with-apps_20120320.pdf>.

Armour Energy (2014) Third part independent certification of 350 PJs (3C) contingent resources Lawn Hill Shale, Egilabria 2 DW1, ATP1087, Queensland. Viewed 07/08/2017, <http://www.armourenergy.com.au/assets/2014/2014.07.16%20-%20ASX%20Announcement%20Maiden%20Contingence%20Resource%20Lawn%20Hill20Shale20Egilabria20220DW1.pdf>

Armour Energy (2015) 66% increase in prospective gas resources in Northern Australia. Maiden prospective gas resources in the Tawallah Group, McArthur Basin (NT) and in the Riversleigh Shale Formation (QLD). Viewed 07/08/2017, <http://www.armourenergy.com.au/assets/1475615.pdf>.

Armour Energy (2017a) Northern Territory. Viewed 16/01/2018, <https://www.armourenergy.com.au/northern-territory/>.

Armour Energy (2017b) Queensland. Viewed 16/01/2018, <https://www.armourenergy.com.au/north-west-queensland>.

ASX (2014) Chapter 5 - Additional reporting on mining and oil and gas production and exploration activities. Viewed 16/01/2018, <http://www.asx.com.au/documents/rules/Chapter05.pdf>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

Bacon CA, Calver CR, Boreham CJ, Leaman DE, Morrison KC, Revill AT and Volkman JK (2000) The petroleum potential of onshore Tasmanian: a review. Viewed 16/01/2018, <www.mrt.tas.gov.au/mrtdoc/dominfo/download/GSB71/GSB71.pdf>

Beach Energy (2015) Annual report. Viewed 16/01/2018, <www.beachenergy.com.au/irm/PDF/4440_0/2015BeachEnergyLtdAnnualReport>.

Blue Energy (2013) Blue Energy 2013 Review. Viewed 16/01/2018, <https://blueenergy.com.au/files/media/bul_ar_2013_web.pdf>.

Central Petroleum (2017) Amadeus Basin. Viewed 16/01/2018, <http://centralpetroleum.com.au/our-business/our-licence-areas/amadeus/mereenie-oil-and-gas-field-ol4-ol5/>.

Central Petroleum (2011) Maturation modelling of the western Lander Trough Wiso Basin, Northern Territory. Viewed 16/01/2018, <www.asx.com.au/asxpdf/20110526/pdf/41yw60sk5b7r1s.pdf>.

Close D, Côté A, Baruch E, Altmann C, Mohinudeen F, Richards B, Ilett R, Evans R. and Stonier S (2017) Exploring the Beetaloo: will Australia's first viable shale play be sourced by billion year old gas? The APPEA Journal 57(2).

Comet Ridge (2017a) Galilee Basin. Viewed 16/01/2018, <http://www.cometridge.com.au/Projects_Galilee.htm>.

Comet Ridge (2017b) New South Wales Projects. Viewed 16/01/2018, <http://www.cometridge.com.au/Projects_NSW.htm>.

CORE (Creating Opportunities for Resource Exploration) (2017) Central Petroleum. Viewed 16/01/2018, <https://core.nt.gov.au/__data/assets/pdf_file/0011/378416/Central-Petroleum.pdf>.

DNRM (Department of Natural Resources and Mines) (2017) Queensland's unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DPCSA (Department of the Premier and Cabinet, South Australia) (2017) Cooper Basin gas well information for unconventional resource plays. Viewed 16/01/2018, <http://petroleum.statedevelopment.sa.gov.au/prospectivity/resource_plays/cooper_basin_gas_well_information_for_unconventional_reservoir_plays>.

Draper JJ, Boreham CJ, Hoffmann KL and McKellar JL (2004) Devonian Petroleum Systems in Queensland. PESA Eastern Australian Basins Symposium II, Adelaide, 297–318.

Drillsearch (2015) ASX/Media Release – 2015 reserves and contingent resource statement. Viewed 16/01/2018, <http://www.asx.com.au/asxpdf/20150826/pdf/430t3gtkqdgjjt.pdf>.

DSWPET (2011a) Unconventional reservoir resource assessment for the lower Larapinta Group Amadeus Basin. Central Petroleum Ltd, ASX Announcement, 7 February 2011.

DSWPET (2011b) Unconventional reservoir resource assessment, the Arthur Creek Formation, Georgina Basin, Australia. Central Petroleum Ltd, ASX Announcement, 11 April 2011. Viewed 16/01/2018, <www.asx.com.au/asxpdf/20110411/pdf/41xyzxdrpth0gg.pdf>.

EIA (Energy Information Administration) (2013) Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. United States Energy Information Administration, 730 p. Viewed 16/01/2018, <https://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf>.

Exoma Energy (2012) Interim financial statement. Viewed 16/01/2018, <https://www.google.com.au/url?sa=t&rct=j&q=&esrc=s&source=web&cd=10&ved=0ahUKEwjXyonPjLDVAhVIgLwKHR2uDv4QFghLMAk&url=http%3A%2F%2Fwww.asx.com.au%2Fasxpdf%2F20120510%2Fpdf%2F4265wmkn0fw9n0.pdf&usg=AFQjCNFvJXYWD_gqa6p0ZeOdLQqL7R5MIA>.

GA (Geoscience Australia) (2015) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2017a) Interim Gippsland Basin unconventional resource assessment. Viewed 16/01/2018, <http://www.ga.gov.au/metadata-gateway/metadata/record/104422>.

GA (Geoscience Australia) (2017b) Interim Otway Basin unconventional resource assessment. Viewed 16/01/2018, <http://www.ga.gov.au/metadata-gateway/metadata/record/104440>.

Goldie Divko LM (2015) A review of gas prospectivity: Gippsland region. Department of Economic Development, Jobs, Transport and Resources. Melbourne, Victoria.

Goldstein B, Menpes S, Hill A, Wickham A, Alexander E, Jarosz M, Pepicelli D, Malavazos M, Staritski K, Taliangis P, Coda J, Hill D and Webb M (2012) Roadmap for Unconventional Gas Projects in South Australia. Department for Manufacturing, Innovation, Trade, Resources and Energy, 267p. Viewed 18/01/2018, <https://statedevelopment.sa.gov.au/resourcesUNPUBLISHED/unconventional-gas-projects>.

Hawkins PJ and Green PM (1993) Exploration results, hydrocarbon potential and future strategies for the northern Galilee Basin. APPEA Journal, 33(1), 280–296.

Hawkins PJ and Williams LJ (1990) Review of the geology and economic potential of the Laura Basin. Queensland Resource Industries Record, 1990/2.

Hayes BJ, Nicholls P, Dorey K, Bresnahan R, McDougall W and Wickens C (2016). Comparing basin-centred gas prospectivity in the Bowen-Surat Basin (Queensland, Australia) with the Deep Basin of western Canada and the Piceance Basin of Utah. AAPG 2016 Annual Convention and Exhibition, Abstract. AAPG Search and Discovery Article #10866. Viewed 18/01/2018, <http://www.searchanddiscovery.com/pdfz/documents/2016/10866hayes/ndx_hayes.pdf.html>.

Jell PA (ed.) (2013) Geology of Queensland. Geological Survey of Queensland, Brisbane.

Lakes Oil (2009) Wombat 2 Frac successful – substantial increase in gas flow. Viewed 12/07/2018, <http://www.lakesoil.com.au/index.php/reports-and-announcements?task=callelement&format=raw&item_id=85&element=f85c494b-2b32-4109-b8c1-083cca2b7db6&method=download&args[0]=ba8d41bb1d9155ea73ef7c5896186f74>.

Lakes Oil (2010) ASX Announcement – Lakes Oil, Beach ready to exploit "tight" gas onshore Gippsland. Viewed 12/07/2018, <http://www.lakesoil.com.au/index.php/reports-and-announcements/item/lko-beach-ready-to-exploit-tight-gas-onshore-gippsland?category_id=3>.

Lakes Oil (2017) Onshore Gippsland Basin Permits. Viewed 18/01/2018, http://lakesoil.net.au/2017/10/19/onshore-gippsland-basin-permits/.

Linc Energy (2017) SAPEX (Shale Oil). Viewed 18/01/2018, <http://www.lincenergy.com/sapex_shale_oil.php>.

Metgasco (2011) Quarterly activities report Quarter ended 31 December 2010. Viewed 18/01/2018, <http://www.asx.com.au/asx/statistics/displayAnnouncement.do?display=pdf&idsId=01146528>

Metgasco (2013) Metgasco plans to recommence gas exploration in Northern Rivers NSW. ASX announcement. Viewed 18/01/2018, <http://www.metgasco.com.au/asx-announcements/metgasco-plans-recommence-gas-exploration-northern-rivers-nsw>.

Munson TJ (2014) Petroleum geology and potential of the onshore Northern Territory, 2014. Northern Territory Geological Survey, Report 22, 242 pp.

Nicholls P, Bresnahan R, Hayes BJ, Dorey K and McDougall W (2015) Unconventional resource potential of the Taroom Trough in the southern Surat-Bowen Basin, Queensland, Australia. AAPG/SEG International Conference and Exhibition, Melbourne, Australia, Extended Abstract. AAPG Search and Discovery Article #10804. Viewed 18/01/2018, <http://www.searchanddiscovery.com/documents/2015/10804nicholls/ndx_nicholls.pdf>.

O'Neill C and Danis C (2013) The Geology of NSW. The geological characteristics and history of NSW with a focus on coal seam gas (CSG) resources. A report commissioned for the NSW Chief Scientist's Office, May, 2013. Viewed 18/01/2018, <http://www.chiefscientist.nsw.gov.au/reports/coal-seam-gas-review/csg-background-papers>.

Origin Energy (2017) Beetaloo Basin drilling results indicate material gas resources. Viewed 16/01/2018, <https://www.originenergy.com.au/about/investors-media/media-centre/beetaloo-basin-drilling-results-indicate-material-gas-resource.html>.

Petrofrontier (2011) Petrofrontier copr. Announces successful drilling of Baldwin-2Hst1. Viewed 16/01/2018, <petrofrontier.com/assets/files/press-releases/2011-10-11.pdf>.

PRMS (2007) Petroleum Resources Management System, published by Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, and Society of Petroleum Evaluation Engineers, 49 pp. Viewed 16/01/2018, <http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf>.

Resources and Energy, New South Wales (2017a) Darling Basin. Viewed 16/01/2018, <http://www.resourcesandenergy.nsw.gov.au/miners-and-explorers/geoscience-information/nsw-geology-overview/sedimentary-basins/darling-basin>.

Resources and Energy, New South Wales (2017b) Oaklands Basin. Viewed 16/01/2018, <http://www.resourcesandenergy.nsw.gov.au/miners-and-explorers/geoscience-information/nsw-geology-overview/sedimentary-basins/oaklands-basin>.

Resources and Energy, New South Wales (2012) NSW Code of Practice for Coal Seam Gas Fracture Stimulation Activities. Viewed 16/01/2018, <http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0018/516114/Code-of-Practice-for-Coal-Seam-Gas-Fracture-Stimulation.pdf>.

Revie D (2017a) Unconventional petroleum resources of the Roper Group, McArthur Basin. Northern Territory Geological Survey, Record 2017-002.

Revie D (2017b) Volumetric resource assessment of the lower Kyalla and middle Velkerri formations of the McArthur Basin. AGES conference, Alice Springs, March 2017.

RISC (2013) ASX reserves and reousrces reporting for oil and gas companies. Public seminar, July 2013. Viewed 16/01/2018, <http://www.asx.com.au/documents/asx-compliance/asx-oil-and-gas-risc-presentation-july-2013_2.pdf>.

Santos (2012) Cooper Basin unconventional gas opportunities and commercialisation. Viewed 16/01/2018, <https://www.santos.com/media-centre/announcements/cooper-basin-unconventional-gas-opportunities-and-commercialisation/>.

Santos (2017) Narrabri Gas Project. Viewed 16/01/2018, <https://www.santos.com/what-we-do/activities/new-south-wales/gunnedah-basin/narrabri-gas-project/>.

Schmoker JW (1995) Method for assessing continuous-type (unconventional) hydrocarbon accumulations. In: Gautier DL, Dolton GL, Takahashi KI and Varnes KL (eds). National assessment of United States oil and gas resources—results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30, 1 CD-ROM.

Schmoker JW (2002) Resource assessment perspectives for unconventional gas systems. AAPG Bulletin, 86(11), 1993–1999.

Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Final Report, March 2018. Viewed 23/04/2018, <https://frackinginquiry.nt.gov.au/inquiry-reports?a=494286>.

Senex (2013) ASX Announcement – Major contingent gas resource upgrade to 5.5 tcf. Viewed 16/01/2018, <http://www.senexenergy.com.au/investor-centre/files/major-contingent-gas-resource-upgrade-to-5-5-tcf/>.

SPE (Society of Petroleum Engineers) (2007) SPE Petroleum Resources Management System Guide for Non-Technical Users, 4 pp. Viewed 16/01/2018, <http://www.spe.org/industry/docs/PRMS_guide_non_tech.pdf>.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Strike Energy (2015) ASX Announcement – DUG Australia conference presentation – July 2015. Viewed 16/01/2018, <http://www.strikeenergy.com.au/wp-content/uploads/2015/07/20150729-DUG-July-2015-Presentation.pdf>.

UPR (Upstream Petroleum Resources Working Group) (2015) Coal seam, shale and tight gas in Australia: resources assessment and operation overview 2015, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/UPR%20Unconventional%20Resources%20Report%202015%20-%20Final_0.pdf>.

UPR (Upstream Petroleum Resources Working Group) (2016) Coal seam, shale and tight gas in Australia: resources assessment and operation overview 2016, Geoscience Australia, Canberra.

Vu TAT, Horsfield B and di Primio R (2011) Gas shale potential of the Amadeus and Georgina basins, Australia: preliminary insights. Geoscience Australia Record, 2011/10, 39 pp. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7893-007c-7506-e044-00144fdd4fa6>.

Ward CR and Kelly BFJ (2013) Background paper on New South Wales Geology. Report for the Office of the NSW Chief Scientist and Engineer, August, 2013. Viewed 16/01/2018, <http://www.chiefscientist.nsw.gov.au/reports/coal-seam-gas-review/csg-background-papers>.

Warner D, Ambrose G and Heugh J (2012) Potential for unconventional plays in the Lower Larapinta Petroleum System of the Amadeus Basin. In: Ambrose GJ and Scott J (eds), Central Australian Basins Symposium III. Petroleum Exploration Society of Australia, Special Publication, 7 pp.

Weatherford Laboratories (2017) Kyalla and middle Velkerri Resource Assessment: Gorrie, Beetaloo, OT Downs, and Broadmere Sub-basins. Study Project No. AB.74329. Northern Territory Geological Survey, Record 2017.003.

Wells AJ and O’Brien PE (eds) (1994) Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation, Bulletin, 241.

Appendix B Regional Maps

Maps of the regional datasets are presented in Appendix B (Figures B.1 to B.22) and a full list of the datasets incorporated in the data inventory discussed in the main report. It is expected that in future stages of assessment, the range of factors and analysis undertaken will be broadened as basin short-listing is progressed.

The datasets provide information on a range of factors seen as pertinent in the Rapid Regional Prioritisation Phase. They inform aspects relating to groundwater, surface water, environmental assets and social factors

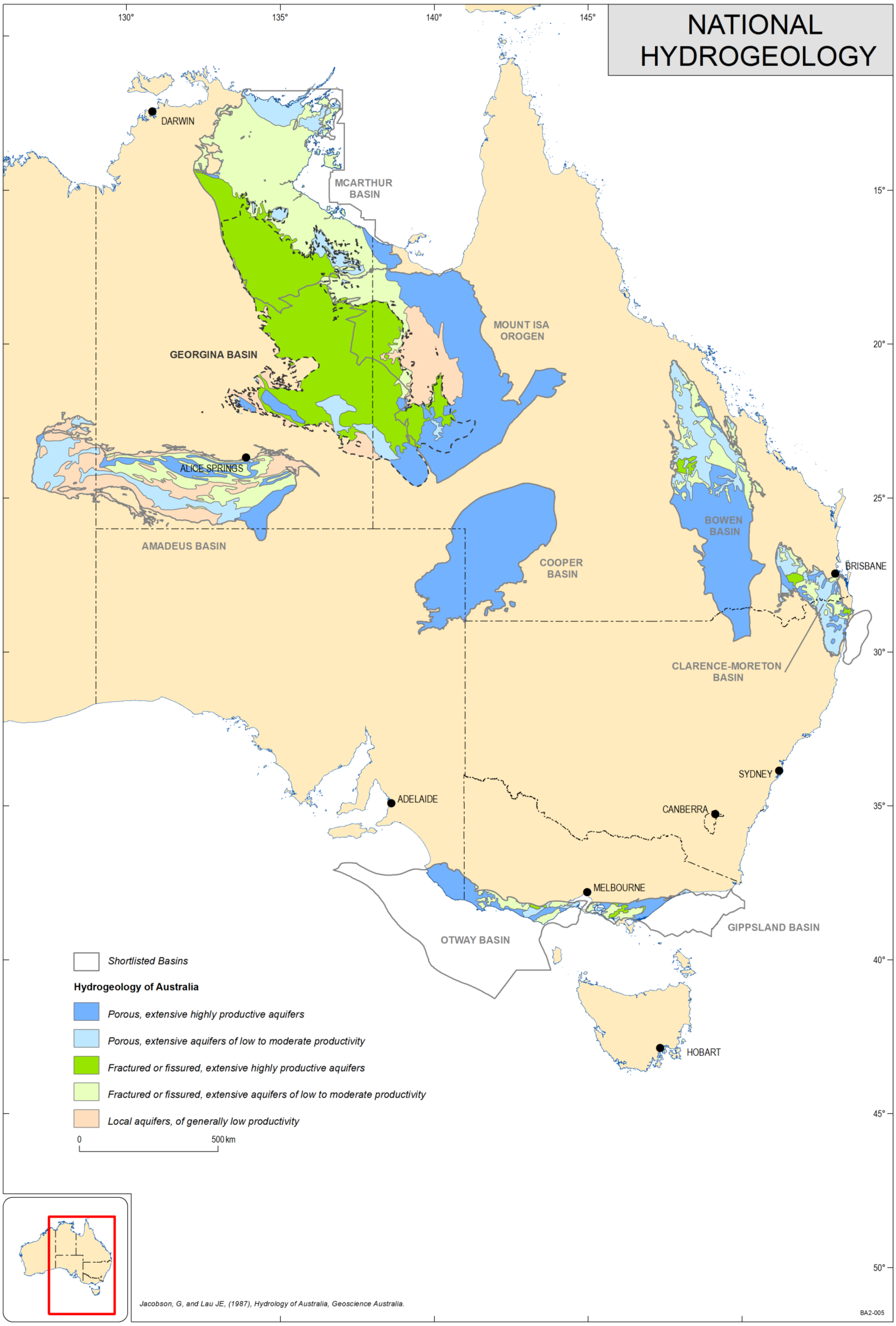

Figure B.1 Classification of principal aquifer types from the national hydrogeology map (Jacobson and Lau, 1987).

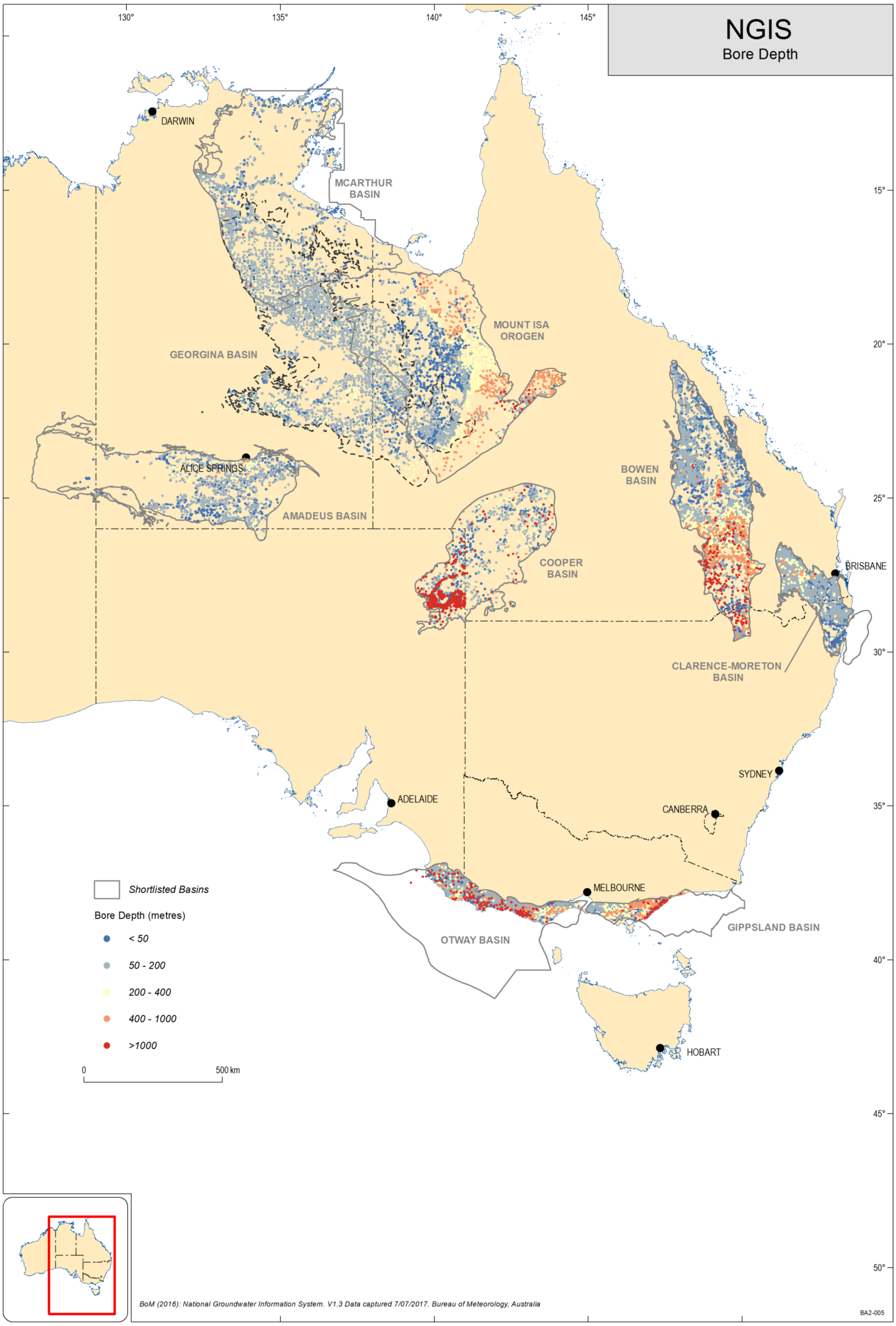

Figure B.2 Depth of groundwater bores in the basins analysed, derived from the National Groundwater Information System (BOM, 2016).

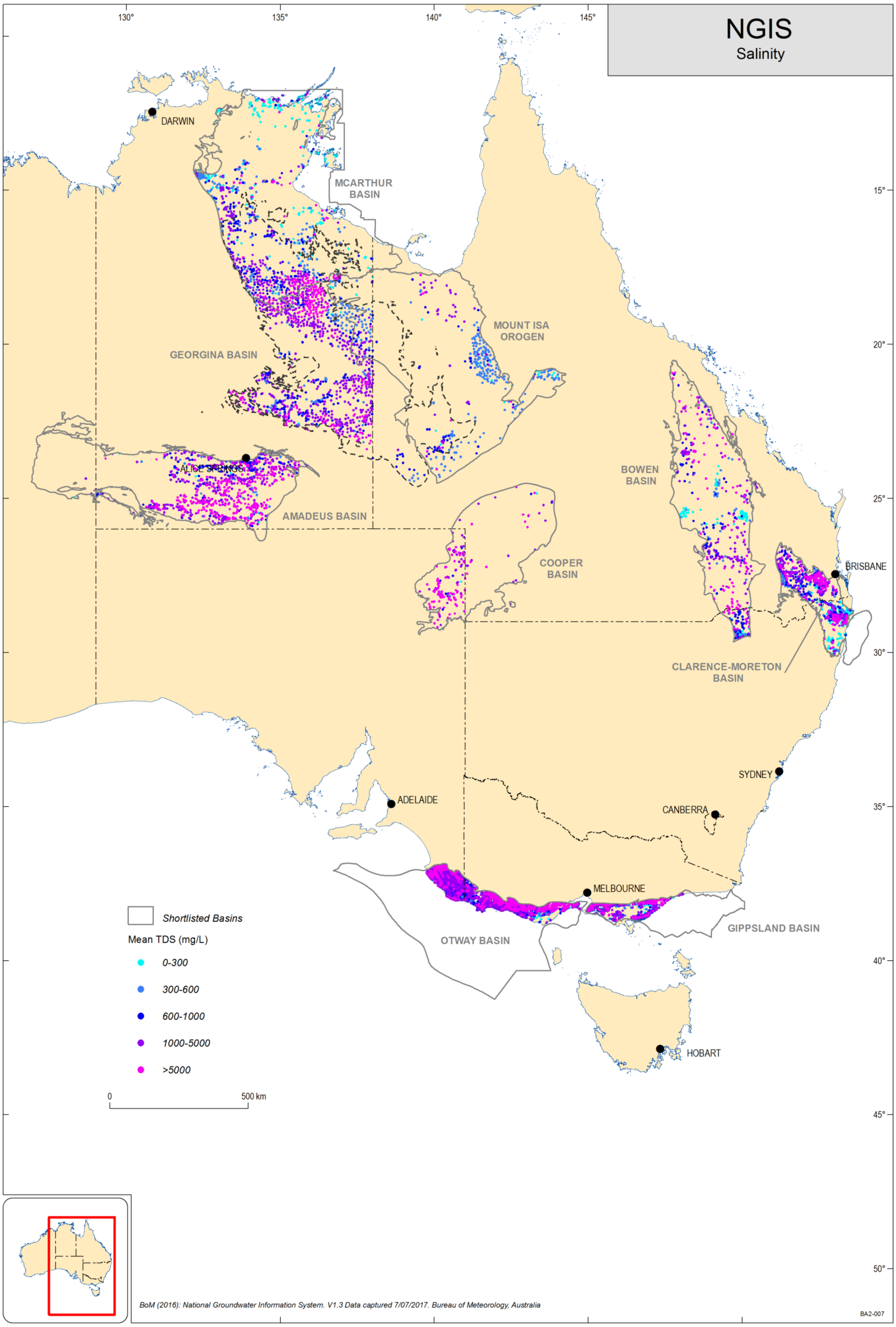

Figure B.3 Estimated salinity values, expressed as total dissolved solids (mg/L) for groundwater bores in the National Groundwater Information System (BoM, 2016).

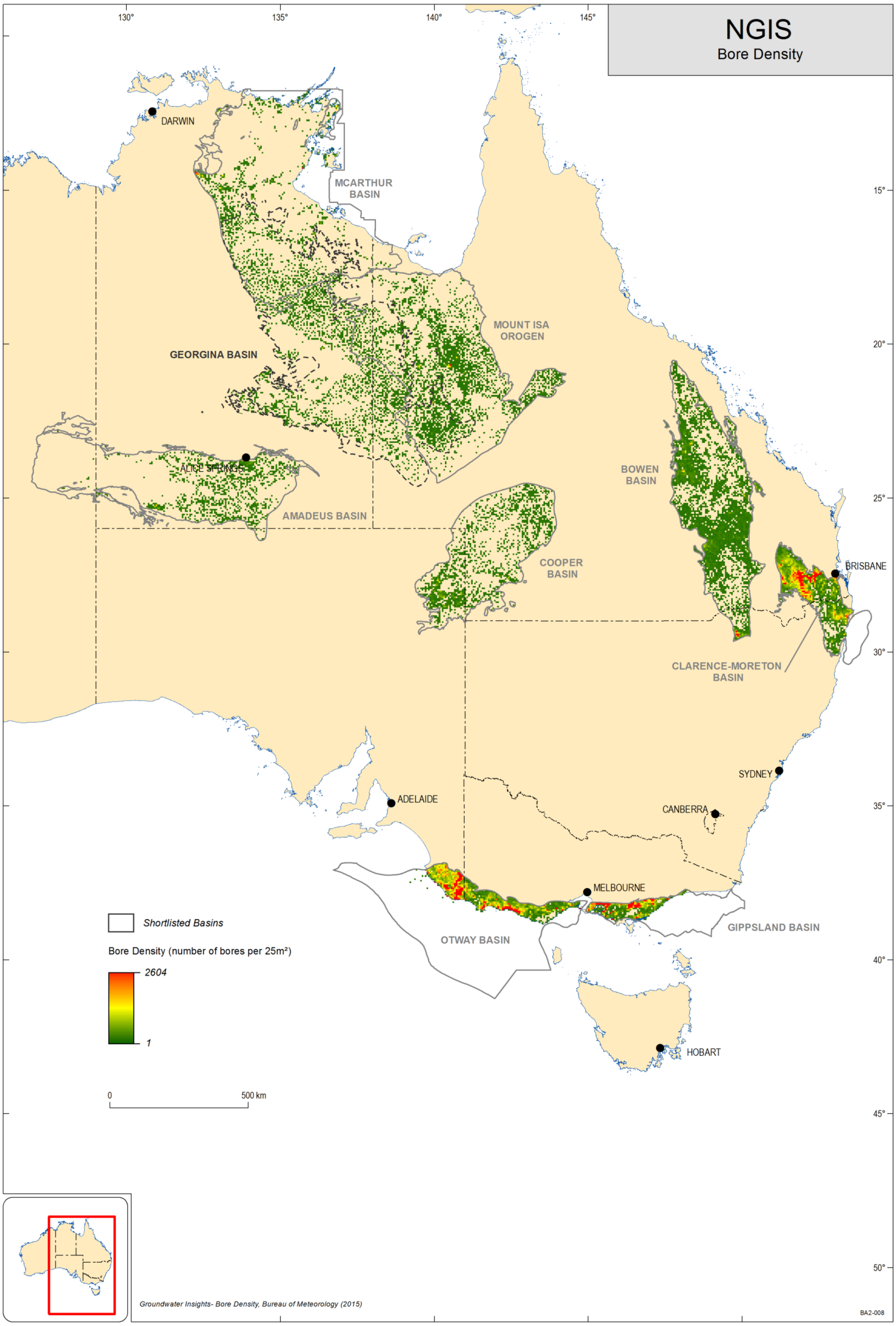

Figure B.4 Density of groundwater bores found in the National Groundwater Information System, as displayed in Australian Groundwater Insight (BOM, 2015).

Figure B.5 Location of internationally important (Ramsar-listed) wetlands and nationally important wetlands (Directory of Important Wetlands in Australia) found within the extents of each basin area (DoEE, 2016a; DoEE, 2010).

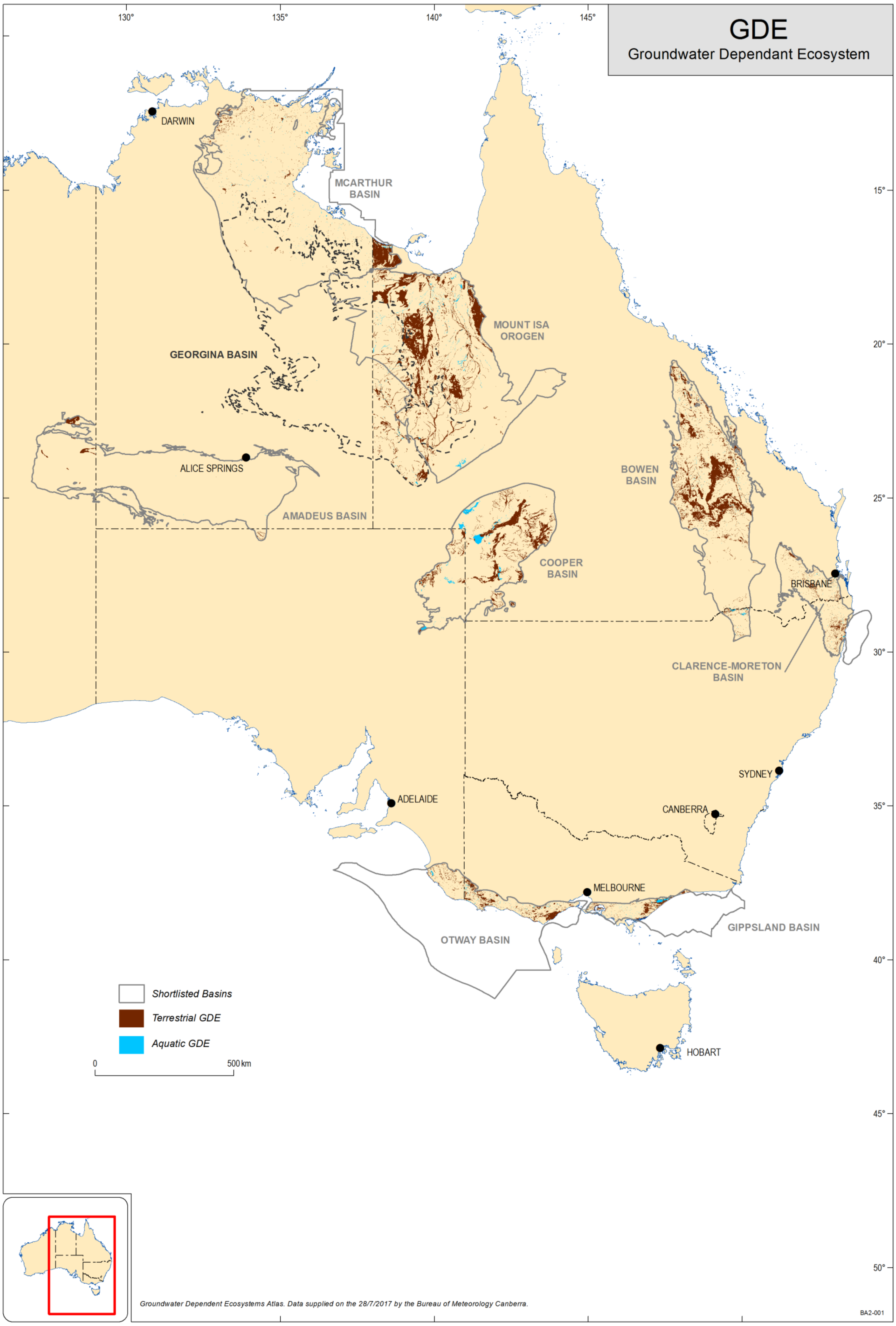

Figure B.6 Geographic extent of areas with at least a moderate potential for groundwater-dependent ecosystems, as found in the Groundwater Dependent Ecosystem Atlas (BOM, 2017).

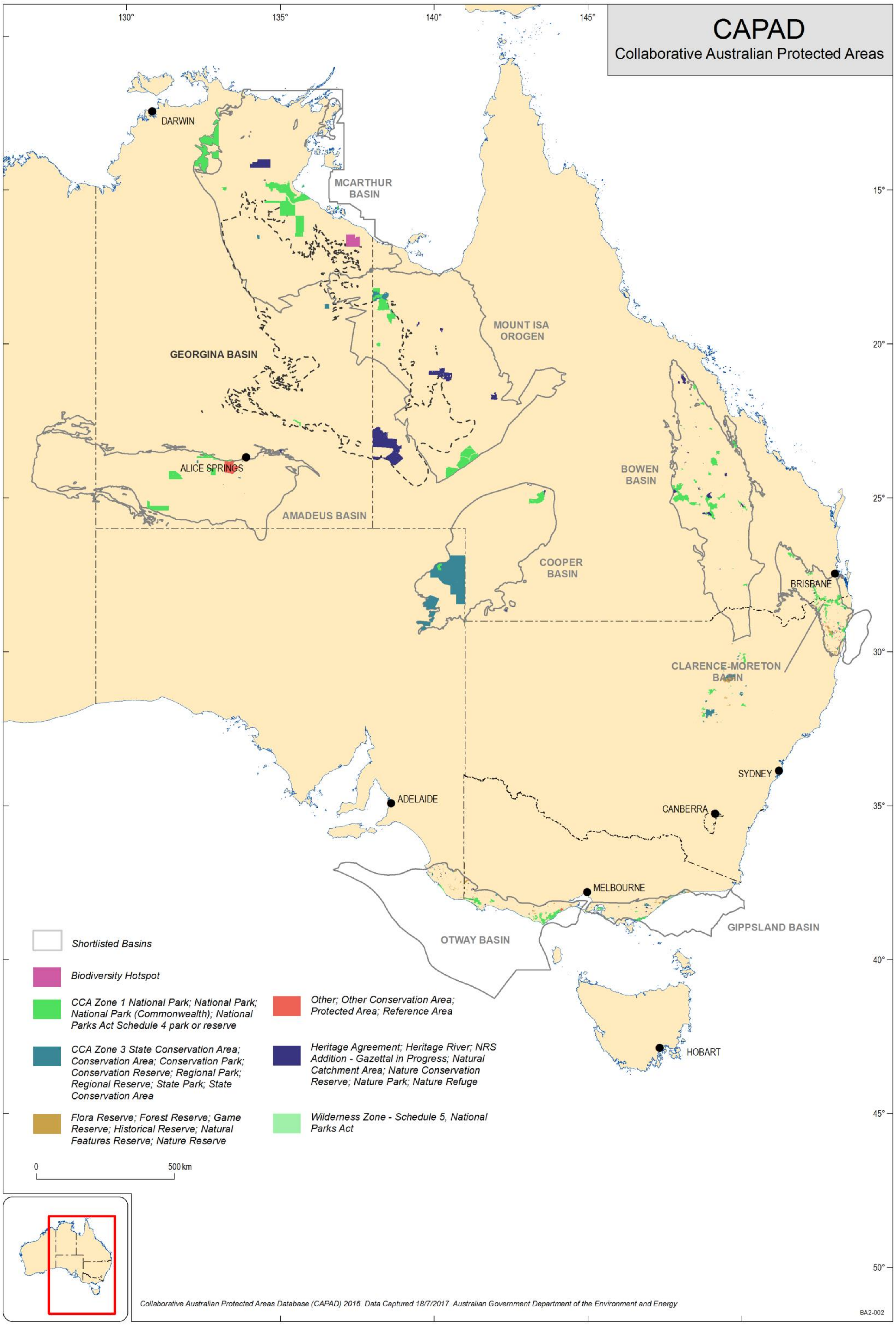

Figure B.7 Extent of protected areas and reserves found in the Collaborative Australian Protected Area Database (DoEE, 2016b).

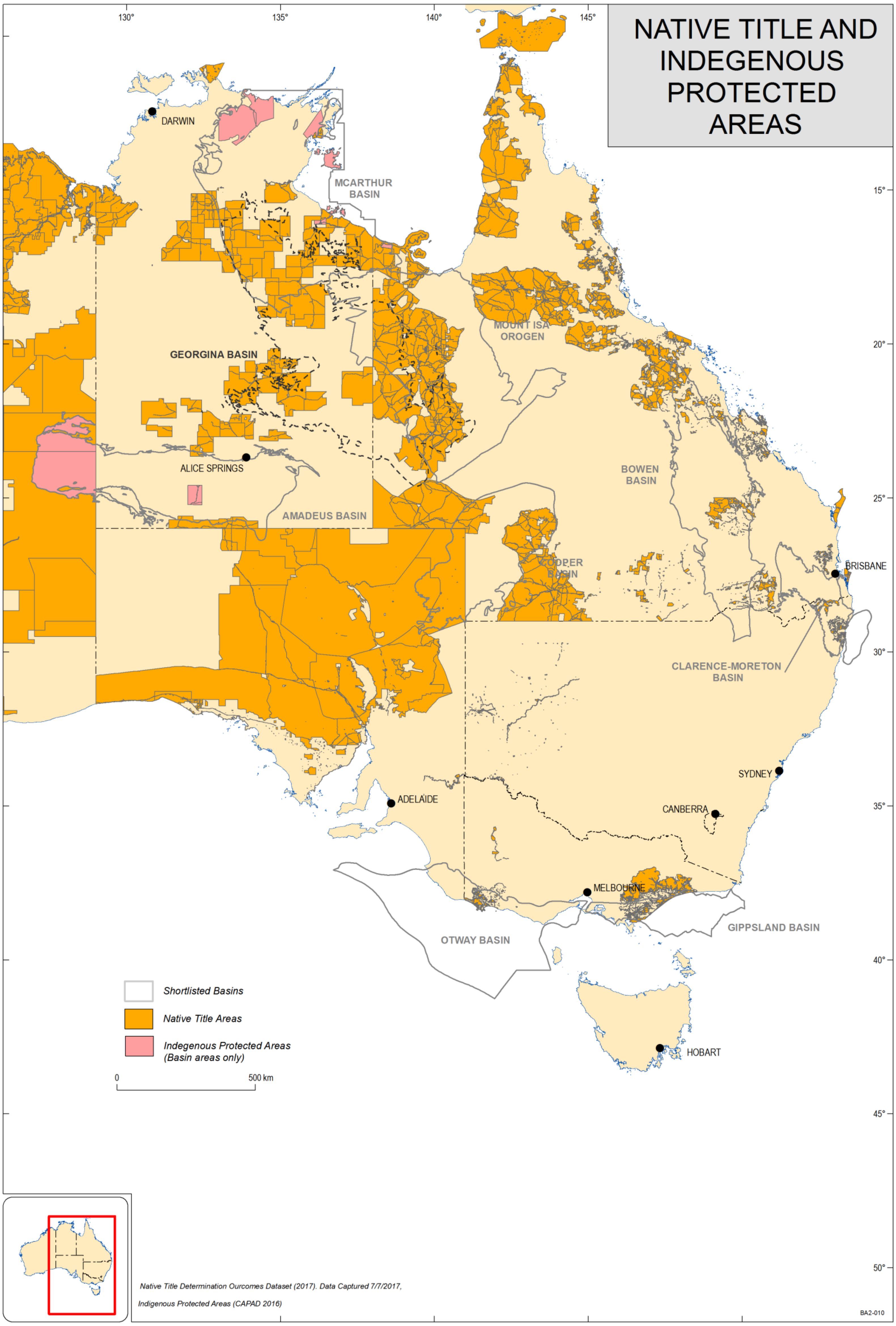

Figure B.8 Extent of areas identified as Indigenous Protected Area in the Collaborative Australian Protected Area Database, and areas where Native Title has been determined to exist (DoEE, 2016b; NNTT, 2017a).

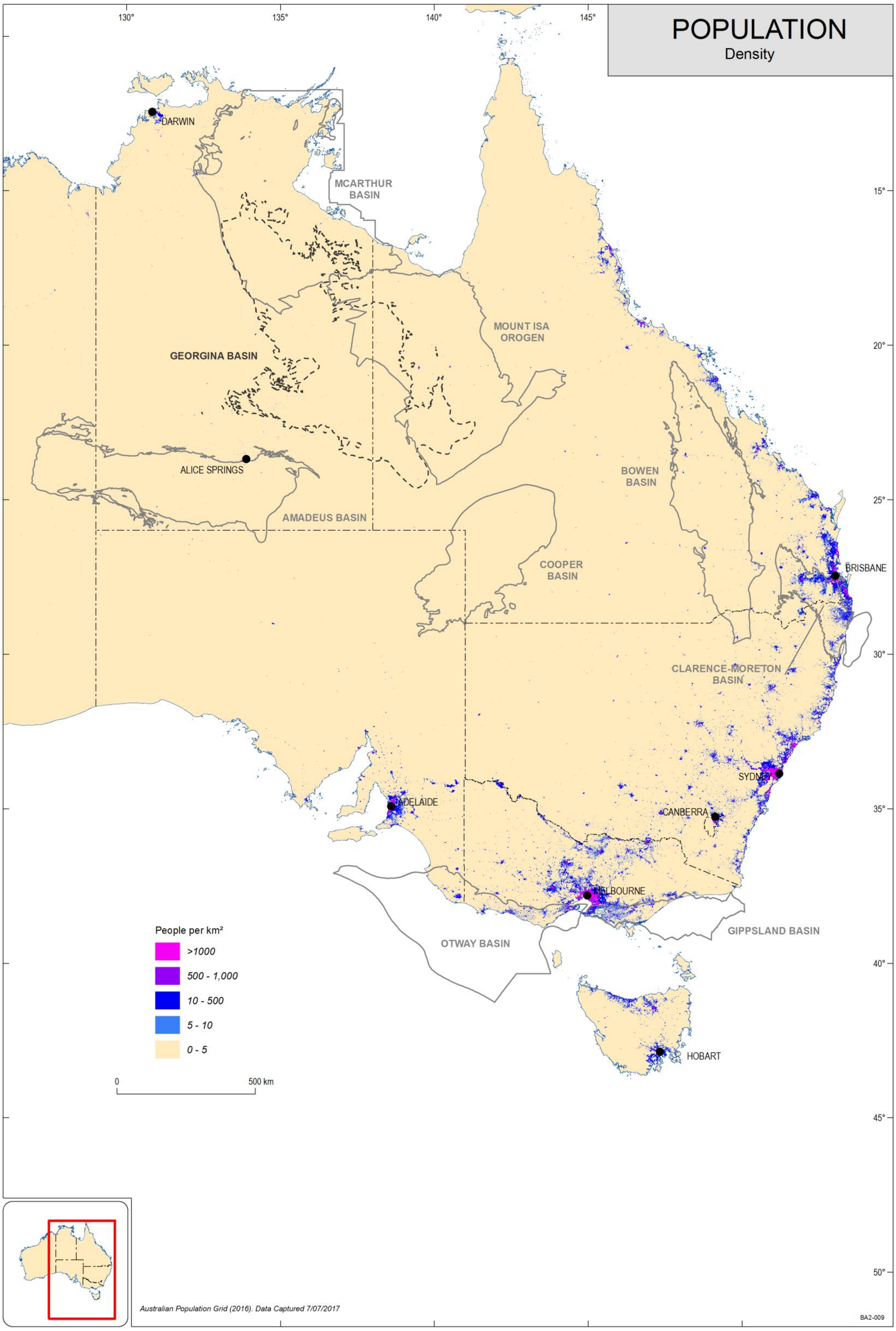

Figure B.9 Distribution of population, expressed as a population density of people per square kilometre in the Australian Population Grid (ABS, 2016).

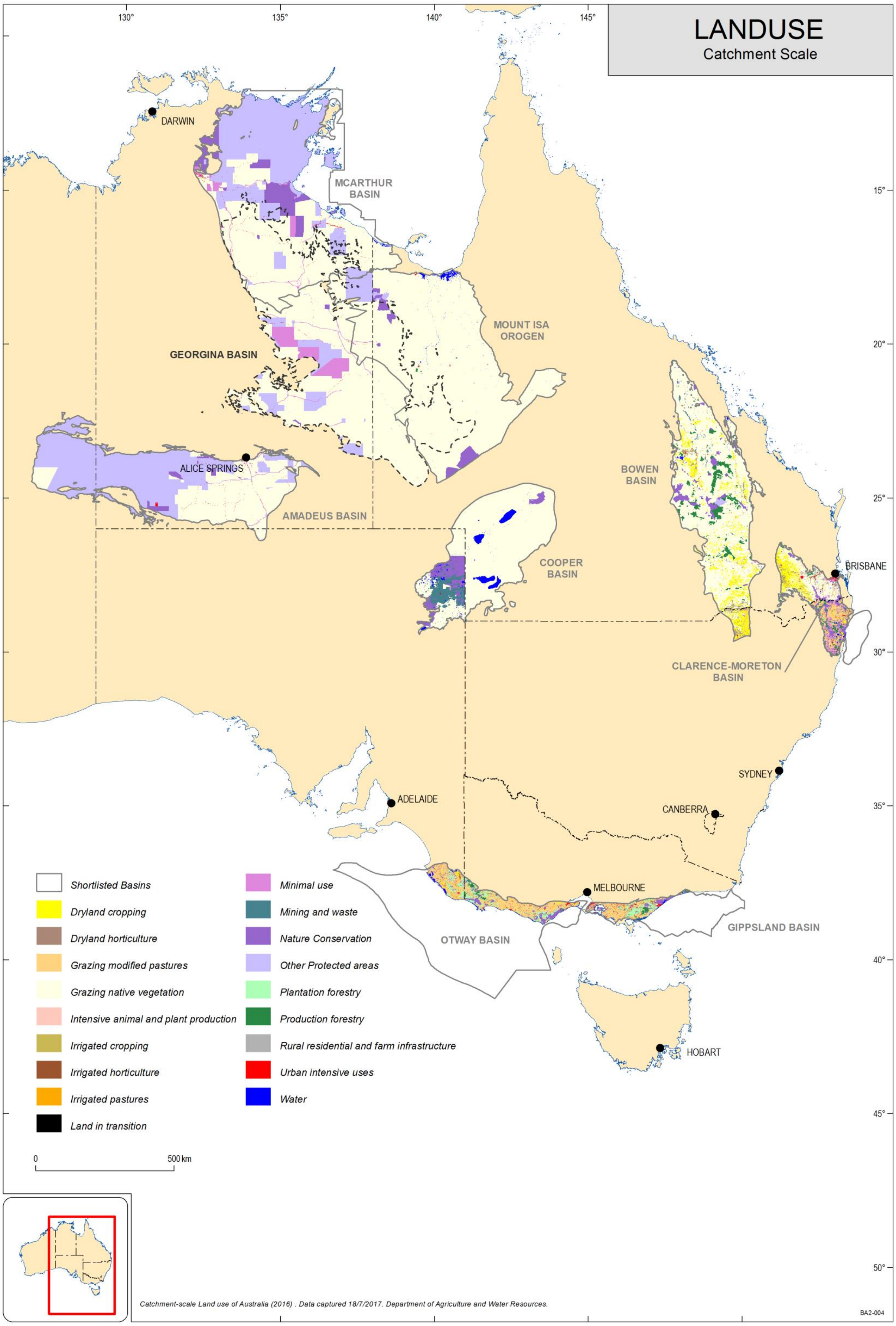

Figure B.10 Land use types as identified in the Catchment-scale Land Use Mapping of Australia dataset (ABARES, 2016).

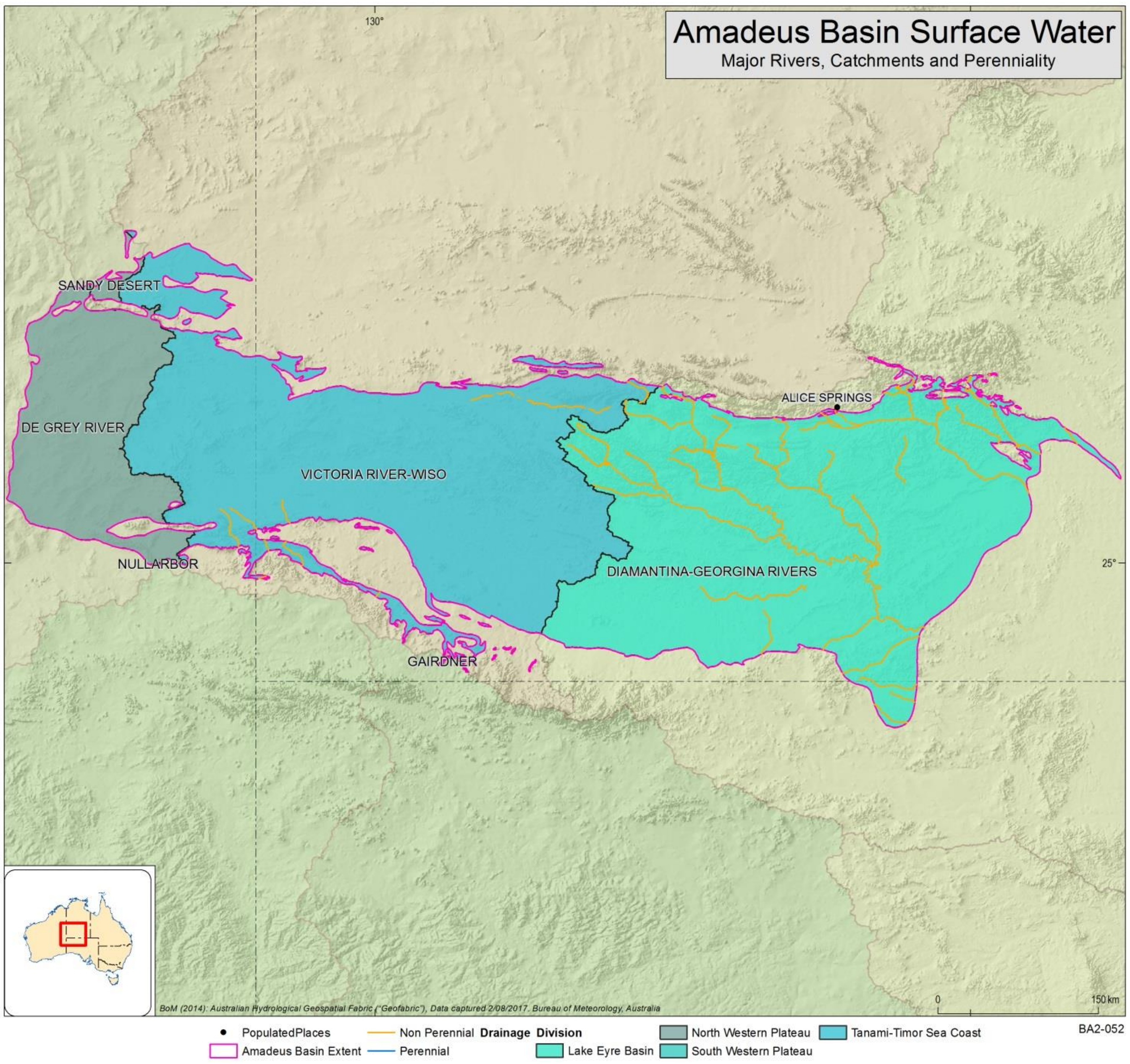

Figure B.11 Surface water systems, including catchments, major rivers and their perenniality, overlying the Amadeus Basin (BOM, 2014).

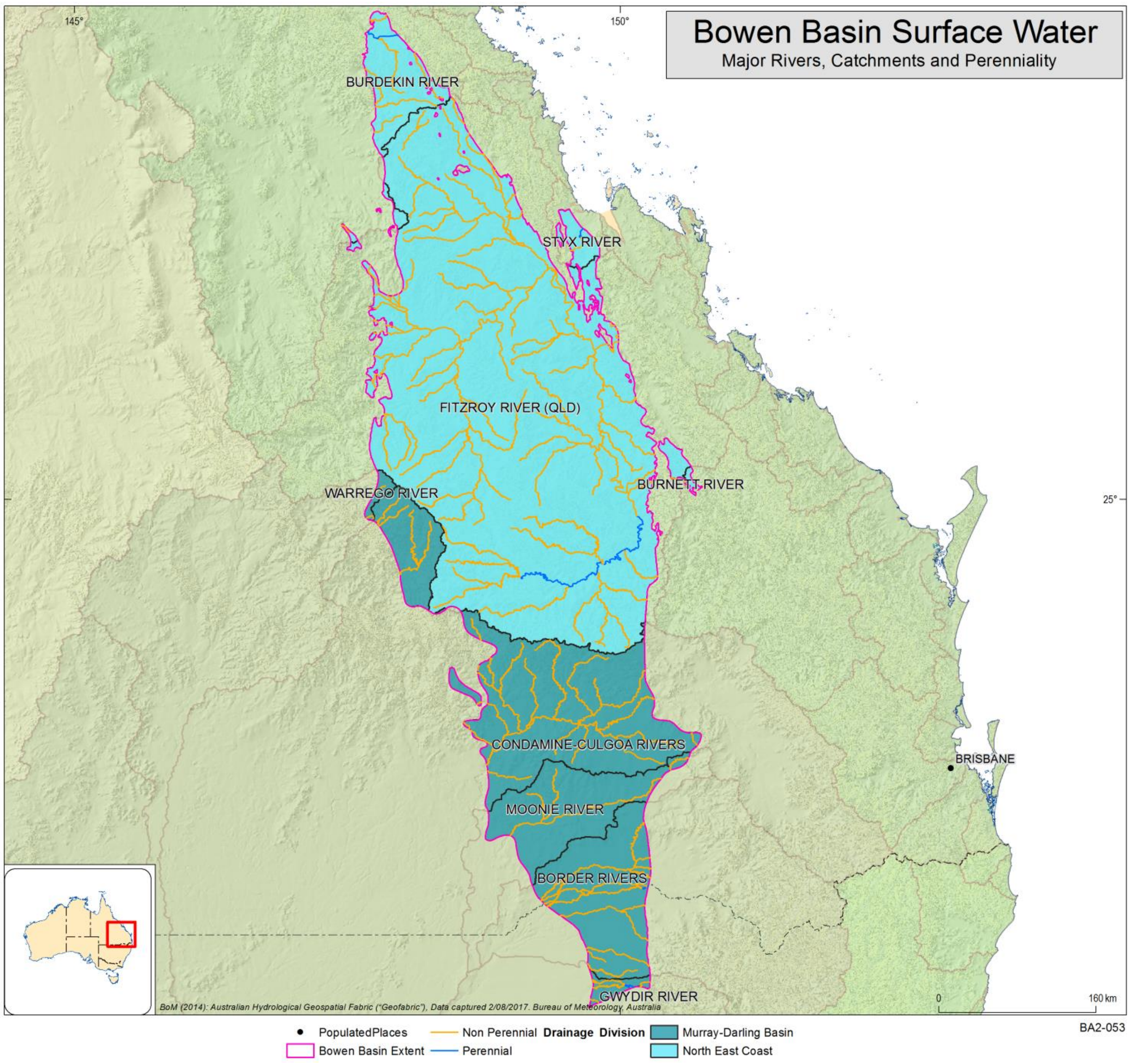

Figure B.12 Surface water systems, including catchments, major rivers and their perenniality, overlying the Bowen Basin (BOM, 2014).

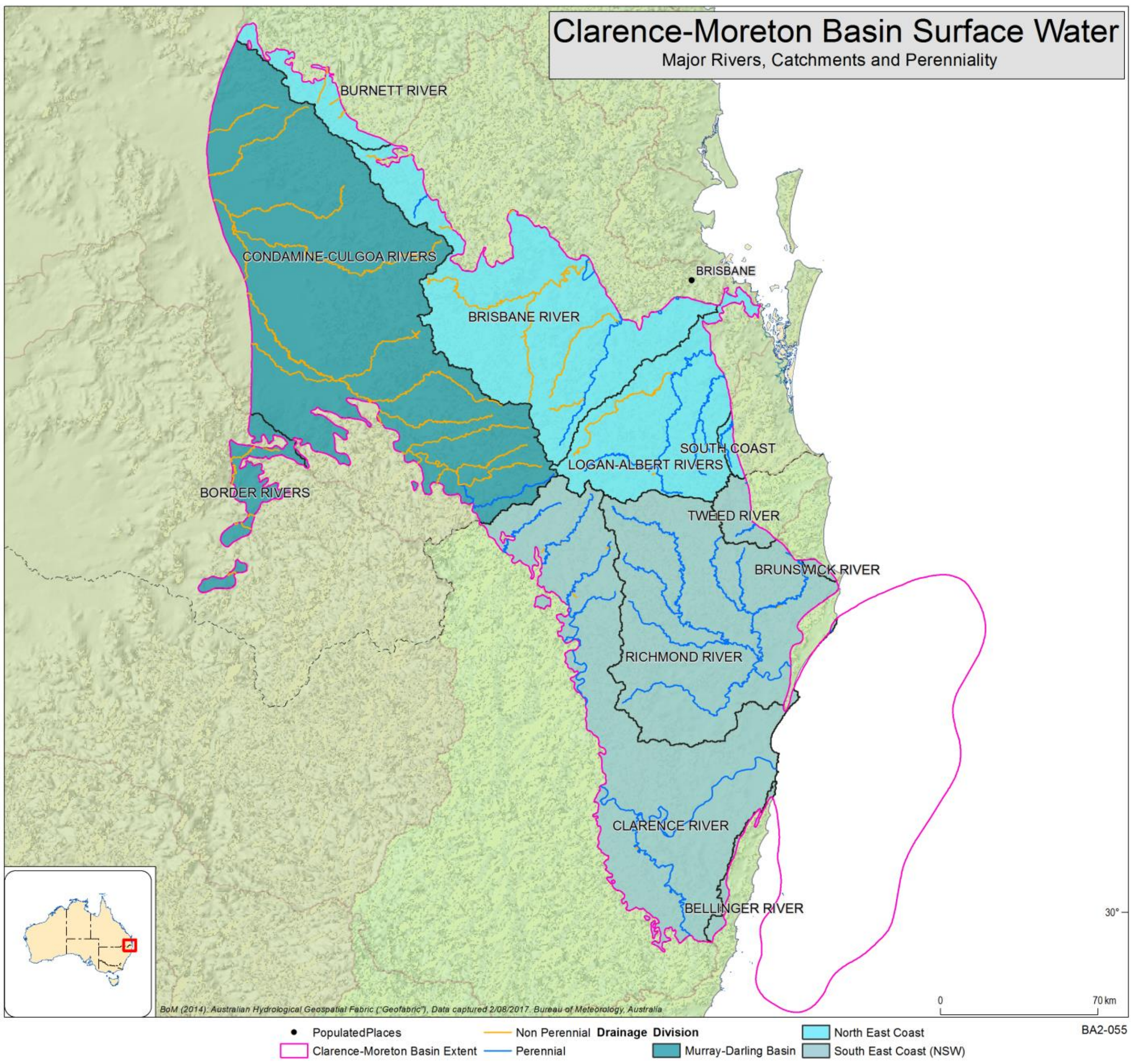

Figure B.13 Surface water systems, including catchments, major rivers and their perenniality, overlying the Clarence-Moreton Basin (BOM, 2014).

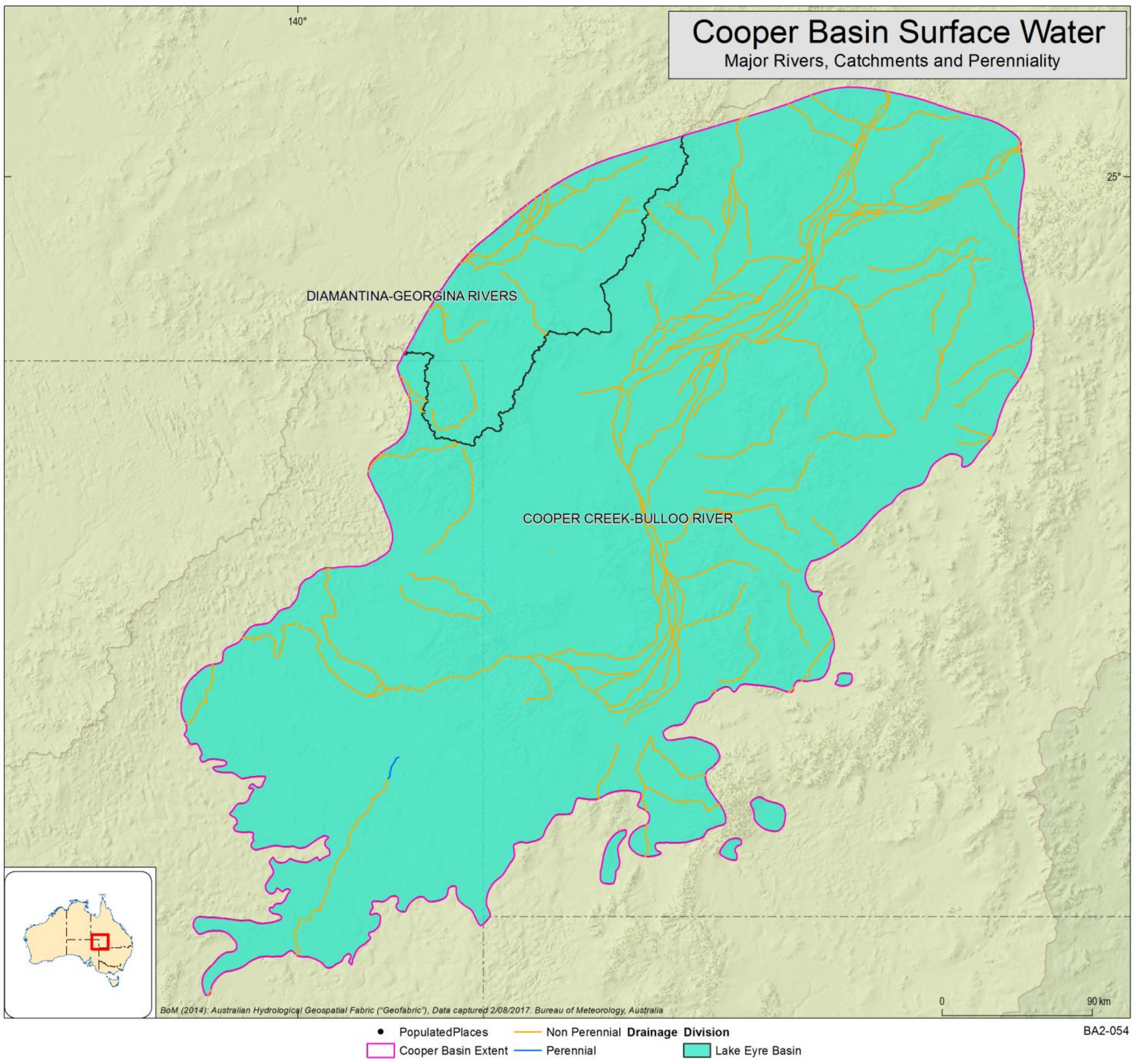

Figure B.14 Surface water systems, including catchments, major rivers and their perenniality, overlying the Cooper Basin (BOM, 2014).

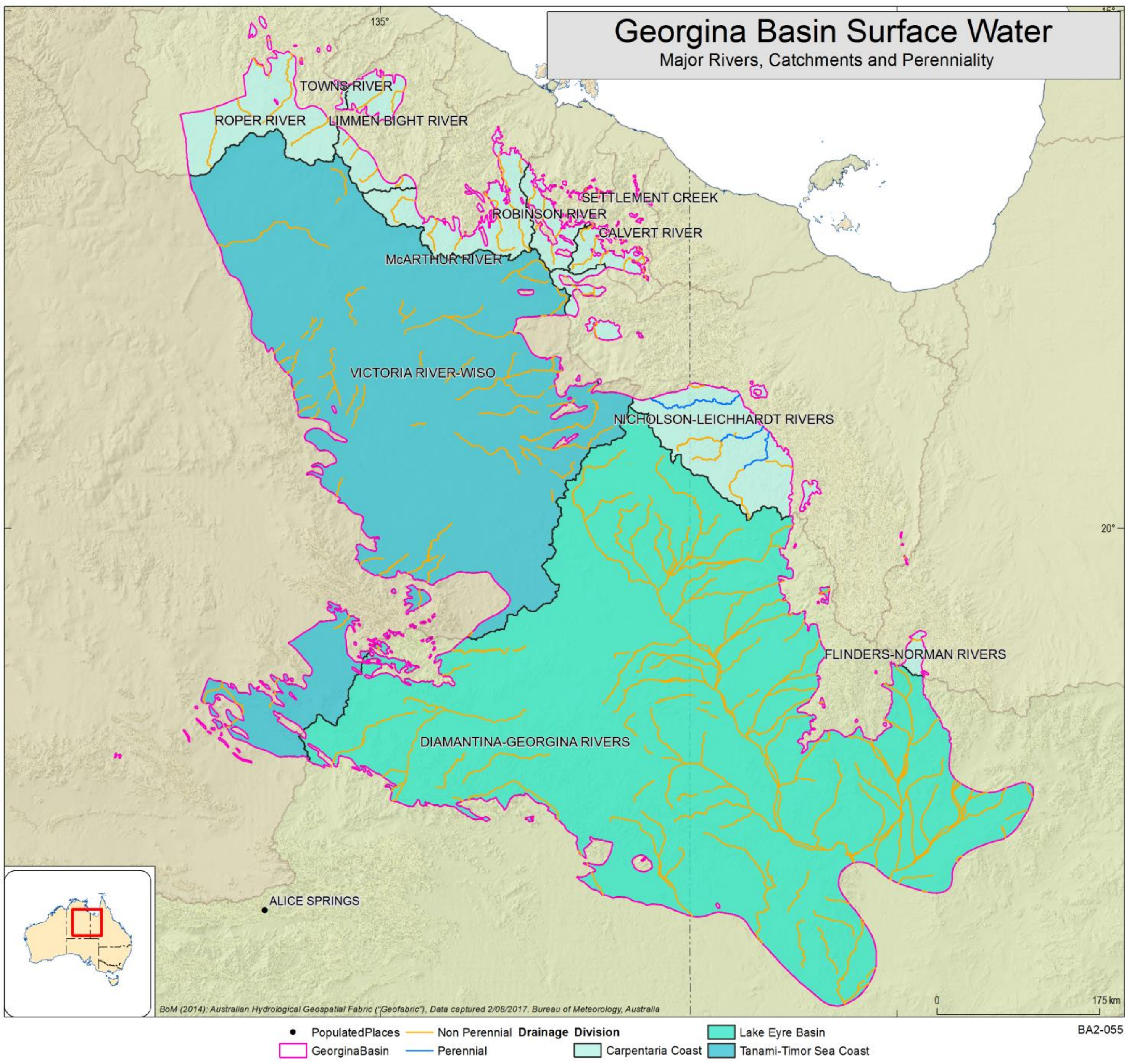

Figure B.15 Surface water systems, including catchments, major rivers and their perenniality, overlying the Georgina Basin (BOM, 2014).

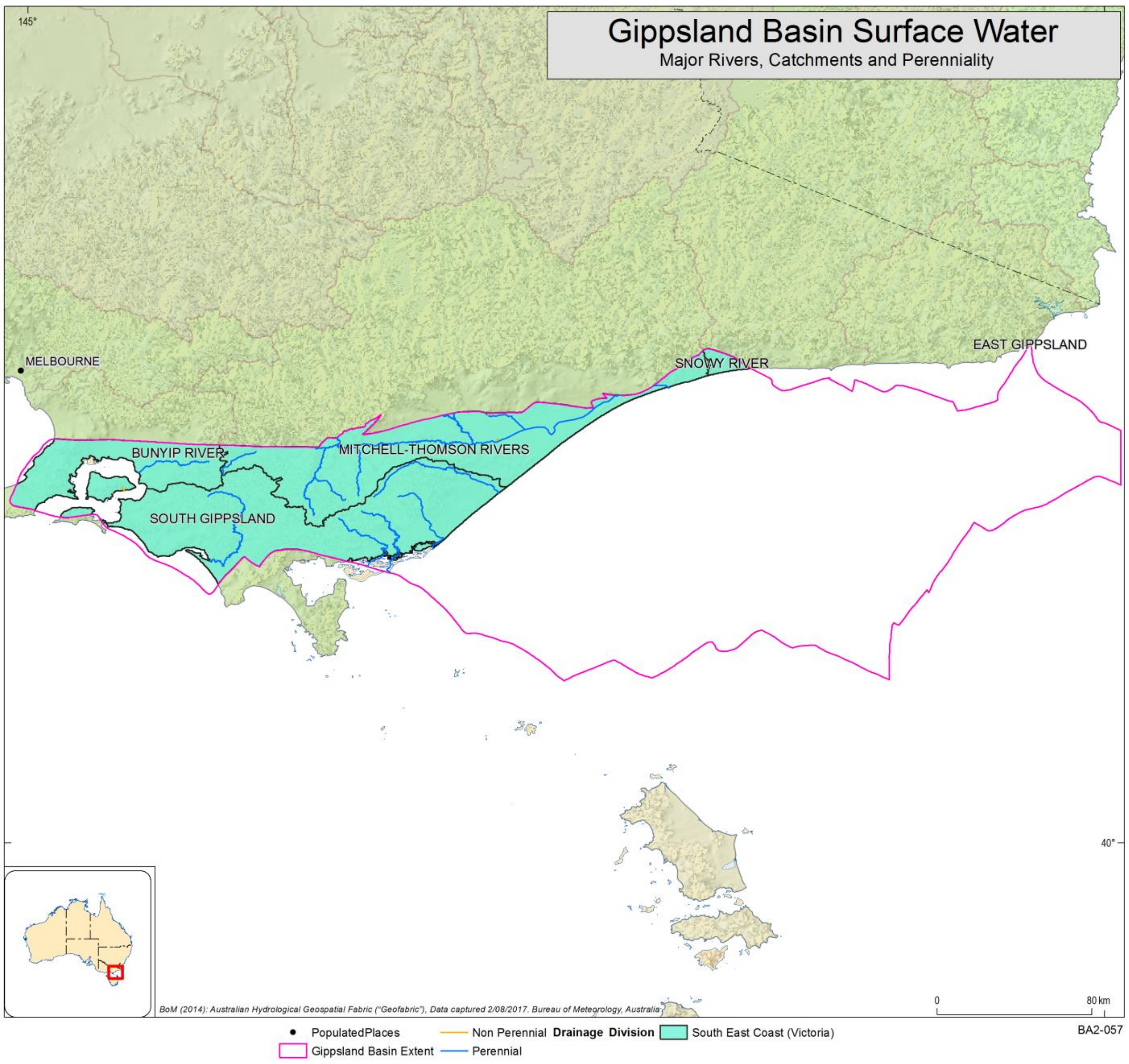

Figure B.16 Surface water systems, including catchments, major rivers and their perenniality, overlying the Gippsland Basin (BOM, 2014).

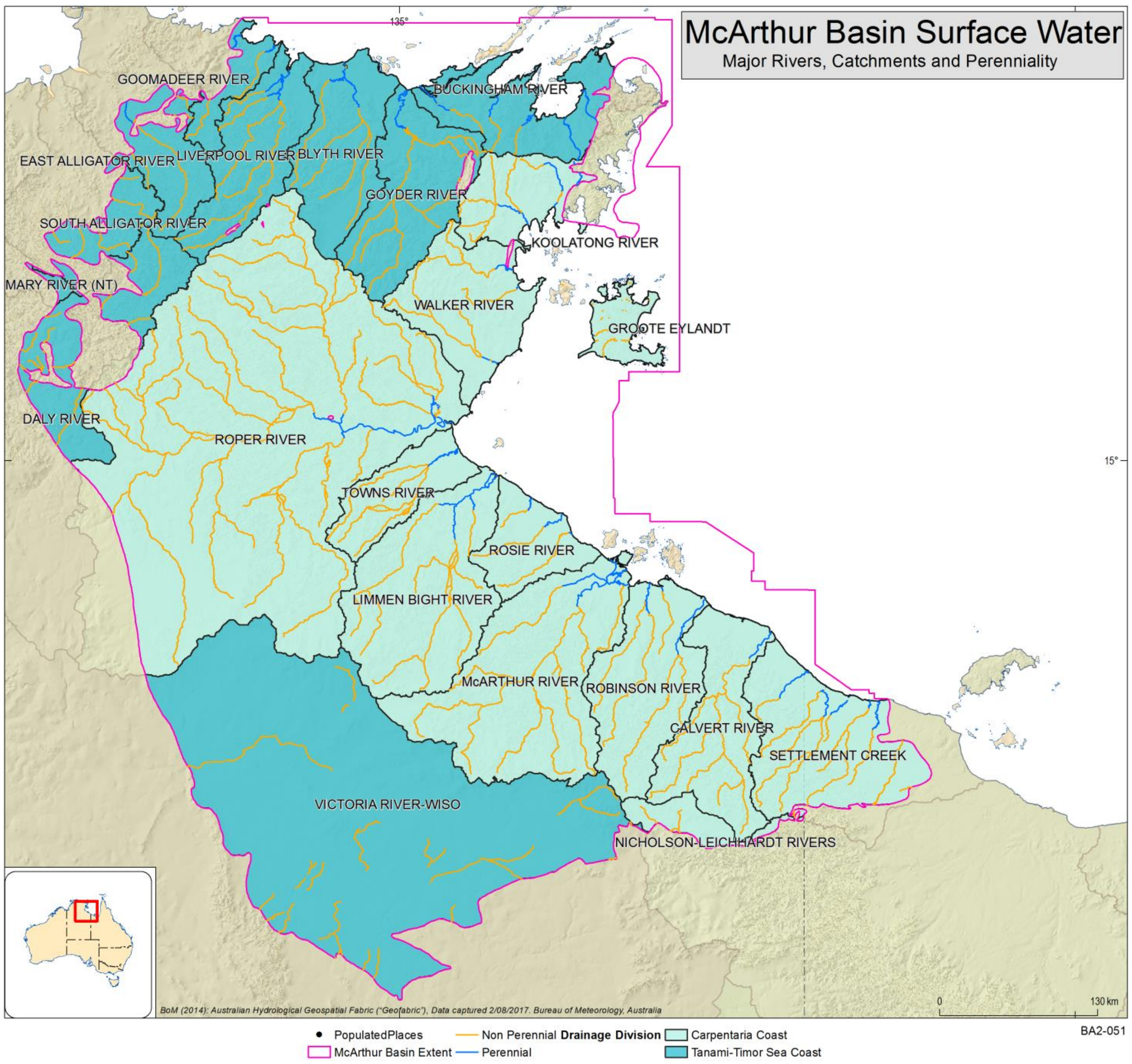

Figure B.17 Surface water systems, including catchments, major rivers and their perenniality, overlying the McArthur Basin (BOM, 2014).

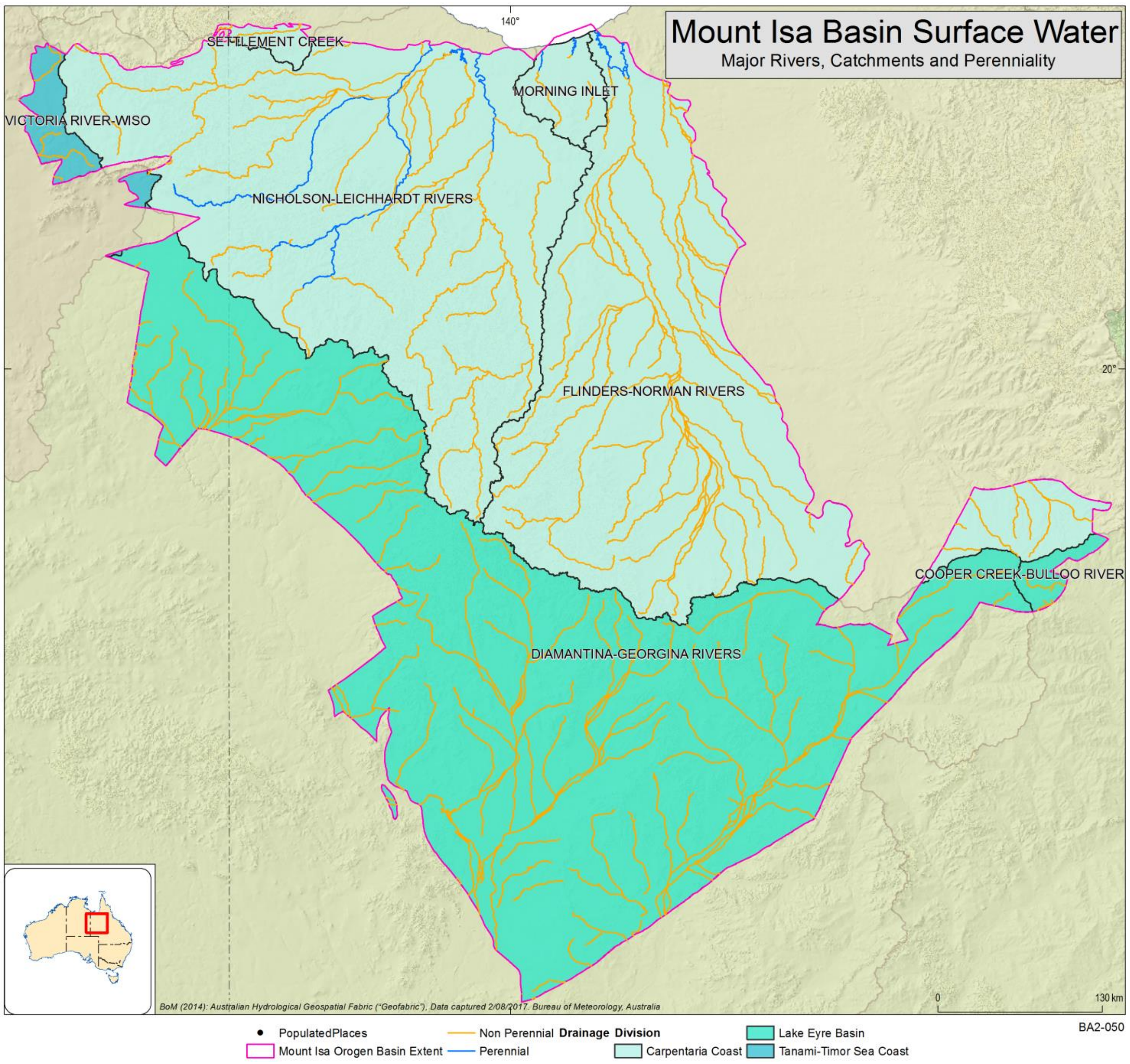

Figure B.18 Surface water systems, including catchments, major rivers and their perenniality, overlying the Mount Isa Province, and therefore including the Isa Superbasin (BOM, 2014).

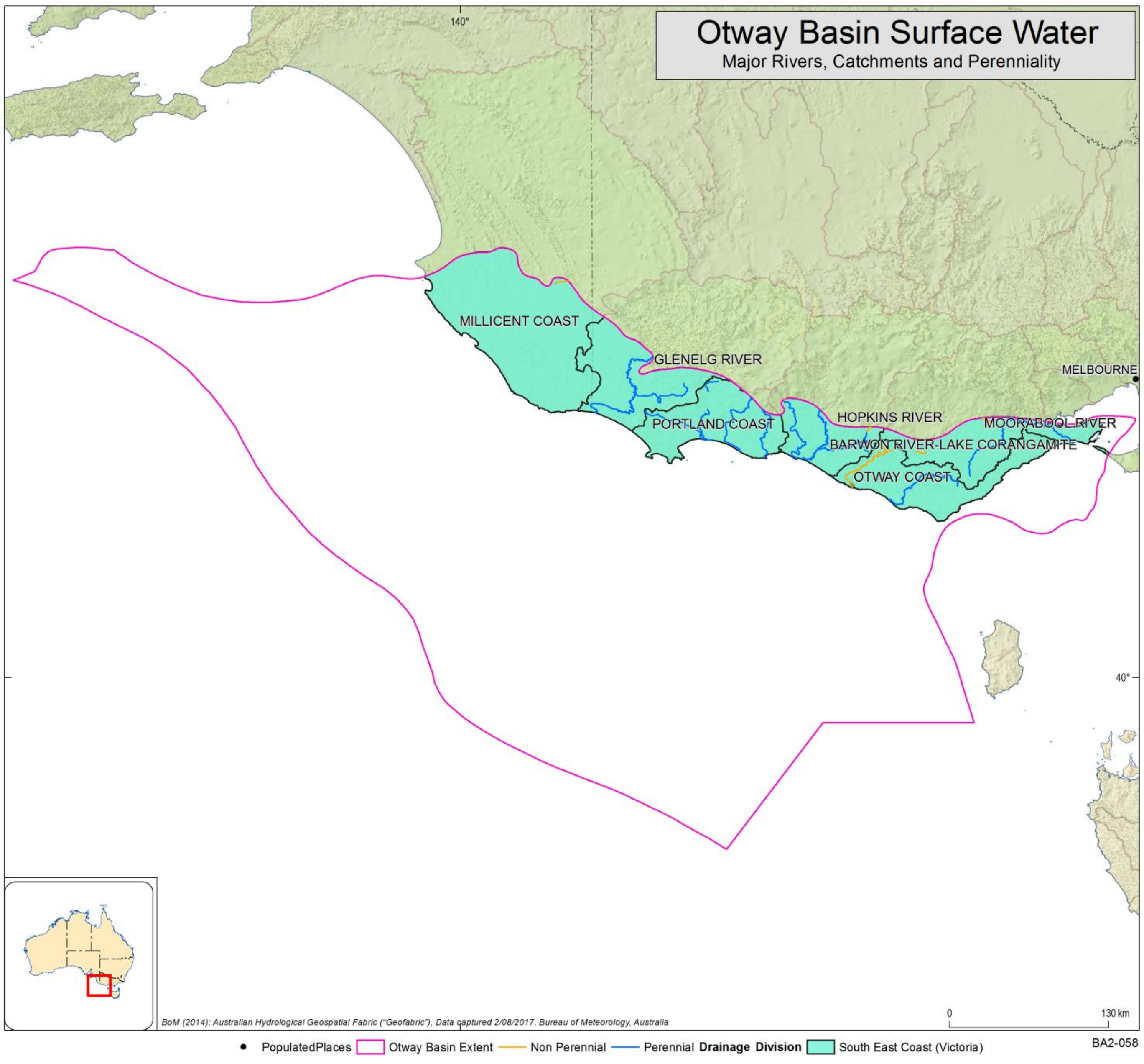

Figure B.19 Surface water systems, including catchments, major rivers and their perenniality, overlying the Otway Basin (BOM, 2014).

Appendix C Basin Audit

Nine onshore basins were identified in which active exploration for shale and or tight gas resources is already underway and possible play, leads or prospects have already been identified. These are as follows:

- Amadeus Basin (Northern Territory, Western Australia, South Australia);
- Bowen Basin (Queensland);
- Clarence-Moreton Basin (Queensland and New South Wales);
- Cooper Basin (Queensland and South Australia);
- Georgina Basin (Northern Territory and Queensland);
- Gippsland Basin (Victoria);
- Isa Superbasin, within the Mount Isa Province (Northern Territory and Queensland);
- McArthur Basin, including the Beetaloo sub-basin (Northern Territory), and;
- Otway Basin (South Australia and Victoria).

Assuming sustained funding of activities and no other impediment to development (e.g. regulatory restrictions; environmental or social concerns), these basins were considered to have potential development timeframes of 10 year or less, and hence were short listed as priority areas for further early research, as part of the basin audit.

A rapid audit was then undertaken on the short-listed basins in order to prioritise areas for further research. This process aimed to:

- capture the current state of knowledge of each basin's shale and tight gas prospectivity, and;
- to identify the water resources and environmental assets that may be affected by shale and tight extraction.

The audit was conducted based on the following rapid regional rapid prioritisation criteria as agreed by GA and DoEE, and hence contains a brief summary of the following topics for each short listed basin.

- **Basin geology and prospectivity:** age, depth, lithology, depositional environment, source rock and reservoir formations, petroleum systems, summary of key unconventional play types (including formation, source rock characteristics); current basin exploration status (i.e. level of basin exploration and development) for shale and tight gas plays; reported production, reserves, contingent or prospective resources; key unconventional wells; approximate development timeframe.
- **Market access and infrastructure:** road/rail access; proximity to existing gas infrastructure (incl. pipelines); distance to market

- **Regulatory:** hydraulic fracturing moratoriums; exploration moratoriums.
- **Environmental constraints:** including groundwater systems; surface water systems; environmentally sensitive areas (e.g. groundwater-dependent ecosystems, important wetlands, national parks).
- **Social factors/constraints:** population distribution; existing land use; culturally significant areas

The project required integration of disparate sources of spatial data on petroleum geology, unconventional gas resources and environmental conditions. The results of each prioritisation theme are clearly presented in tables, maps, matrices and within the basin summary documents in this appendix for the DoEE's consideration to inform decisions on priority areas for further work by the Geological and Bioregional Assessments Program.

C.1 Amadeus Basin

Table C.1 Geology and petroleum prospectivity summary

GENERAL	
Jurisdiction	Northern Territory, South Australia, Western Australia
Area	180,000 km^2
Max. basin depth/ sediment thickness	14,000 m
Age range	Neoproterozoic–Late Devonian
Depositional setting	Shelf, lagoonal, continental and shallow-marine (Neoproterozoic); marine (Cambrian–Ordovician); non-marine (?Silurian–Devonian)
Regional structure	Two phases of extension and thermal subsidence during the late Proterozoic–early Paleozoic; two contractional deformation phases resulting in nappes, folds, thrusts; salt tectonics
Overlying basin(s)	Pedirka and Eromanga basins (southeast); Canning Basin (west)
EXPLORATION STATUS	
Seismic lines	12,986 line km of 2D seismic
Number of petroleum wells	~40
Exploration status - conventional	Producing
Exploration status – shale/ tight gas	Minor tight gas production around conventional producing fields; otherwise under-explored
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Larapintine Supersystem, Centralian Supersystem)
Prospectivity	High
Conventional discoveries	Mereenie 1963 (oil and gas); Palm Valley 1995 (gas); Dingo 1985 (gas); Surprise 2011 (oil)
Hydrocarbon production – total to date	0.41 Tcf cumulative conventional gas production (current to 2014; AERA, 2018); includes production from fracture stimulated tight conventional reservoirs around the Mereenie and Palm Valley fields
2P Reserves	0.32 Tcf conventional reserves (current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	0.4 Tcf remaining conventional resources (current to 2014; AERA, 2018)
Undiscovered resource estimates	Conventional prospective resources unknown; see below for prospective shale/ tight resources
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Tight gas, shale gas
Wells targeting shale/tight gas plays	None targeting shale or tight gas only
Production – shale/ tight gas	None; note production from tight reservoirs in conventional wells (above)
2P Reserves – shale/ tight gas	No reserves booked
Remaining resources (reserves + contingent resources) – shale/ tight gas	None reported

Undiscovered resources estimates – shale/ tight gas	• Horn Valley Siltstone shale gas play best estimated recoverable resource of 16 Tcf (prospective area 7,267 km^2; AWT International, 2013) • Mean probabilistic unrisked prospective recoverable resources for the lower Larapinta Group of 26.2 Tcf, including 11.3 Tcf of Horn Valley Siltstone shale gas (prospective area 7,395 km^2), 9.8 Tcf of Pacoota Sandstone tight gas (prospective area 3,440 km^2) and 5.1 Tcf of Stairway Sandstone tight gas (prospective area 3,440 km^2) (Table A.3; DSWPET, 2011; AERA, 2018)
Hydrocarbon shows, tests – shale/ tight gas	Potential for tight gas indicated by minor gas production from tight reservoirs in conventional fields

C.1.1 Basin Geology

The Amadeus Basin is a Neoproterozoic to Late Devonian sedimentary basin (Edgoose, 2013; Munson, 2014). It is located mainly in the Northern Territory, but also extends into Western Australia and just into South Australia (Figure C.1). The areal extent of the basin is about 180,000 km^2, of which less than one fifth is exposed at the surface (Edgoose, 2013).

The Amadeus Basin contains up to 14 km of clastic, carbonate and evaporitic sedimentary rocks, which were deposited in shallow marine to continental environments during periods of extension and thermal subsidence the late Proterozoic–early Paleozoic and Late Devonian (Figure C.2; Wells et al., 1970; Korsch and Kennard, 1991; Lindsay and Korsch, 1989, 1991; Wellman, 1991; Edgoose, 2013; Munson, 2014). The basin overlies the Musgrave Province in the south, and the Arunta Region in the north. The basin is overlain by the Permian–Triassic Pedirka Basin and the Mesozoic Eromanga Basin to the southeast, and possibly by the Paleozoic Canning Basin to the west (Edgoose, 2013).

The Amadeus Basin is subdivided into a platform area in the south and west, with a 2 km thick sediment cover, and the Ooraminna, Carmichael, and Idirriki sub-basins along the northern margin, in which the sedimentary successions are generally between 6 km and 14 km thick (Lindsay and Korsch, 1989). Structural highs occur throughout the basin, the most pronounced being the Central Ridge, which extends in a broad arch along the southern margin of the northern sub-basins and the Missionary Plain Trough (Figure C.1). It is considered to have initiated in the late Neoproterozoic and was enhanced by salt migration from the Bitter Springs Formation (Lindsay and Korsch, 1991; Oaks et al., 1991).

The Amadeus Basin has undergone a complex tectonic evolution. Areas in the southwest of the basin were mostly affected by the 580–530 Ma Petermann Orogeny (Forman, 1966; Edgoose et al., 2004), and areas in the north were mostly affected by the late Ordovician to Carboniferous Alice Springs Orogeny. The contractional structures developed during these orogenies are often expressed at the surface as recumbent nappes, fault-related folds, and thrust sheets (Stewart, 1967; Forman, 1971; Stewart et al., 1991; Flöttmann and Hand, 1999; Flöttmann et al., 2004); these structures indicate a crustal shortening of 50–125 km (Stewart et al., 1991; Shaw et al., 1991, 1992; Haines et al., 2001).

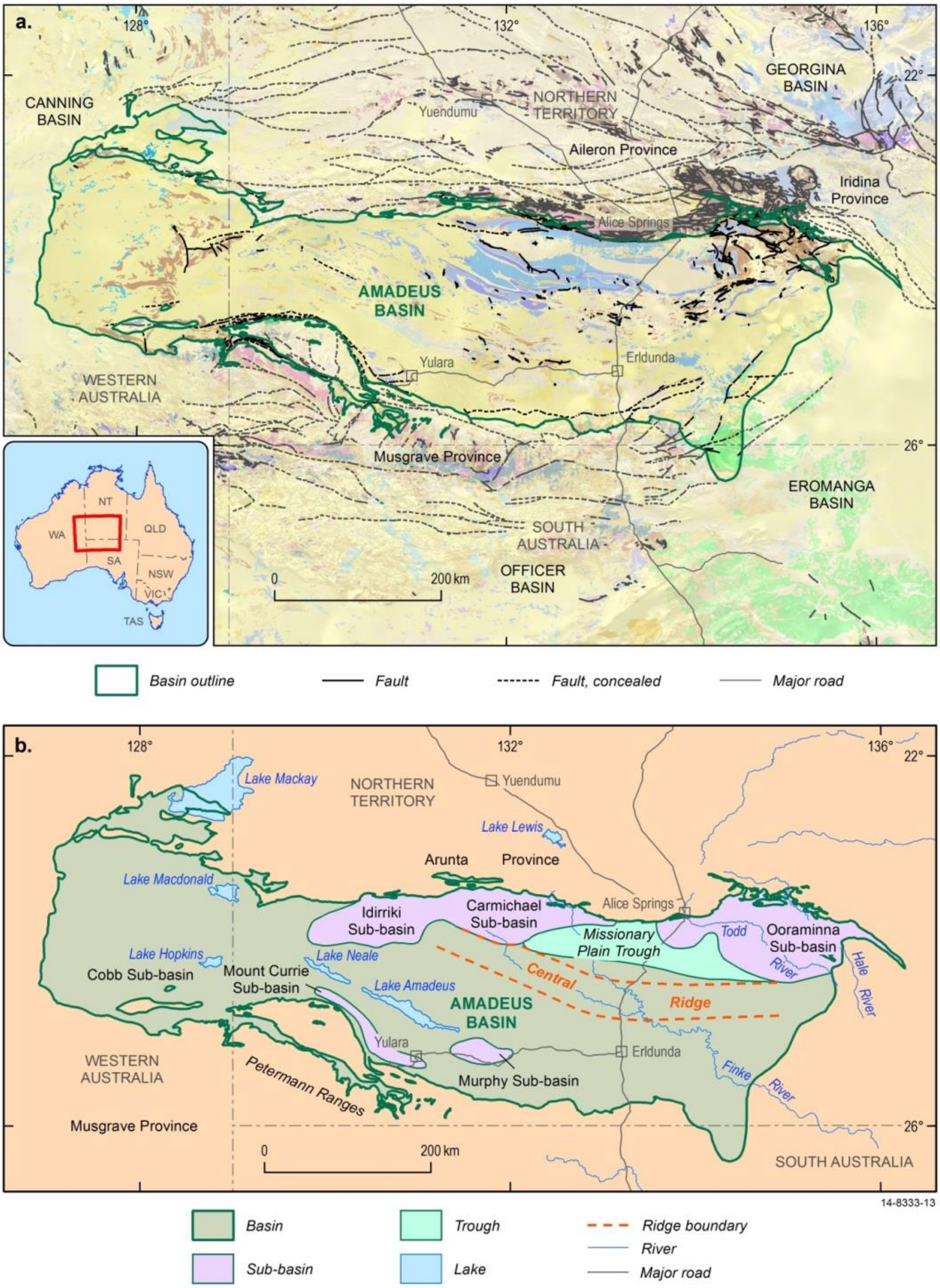

Figure C.1 Location of the Amadeus Basin on a base map of surface geology from Carr et al. (2016). The surface geology is from the 1:1,000,000 scale geology map of Australia (Raymond, 2009), and the outline of the Amadeus Basin is from Stewart et al. (2013). (b) Map of the Amadeus Basin showing locations of the key depocentres (after Lindsay and Korsch, 1989, 1991).

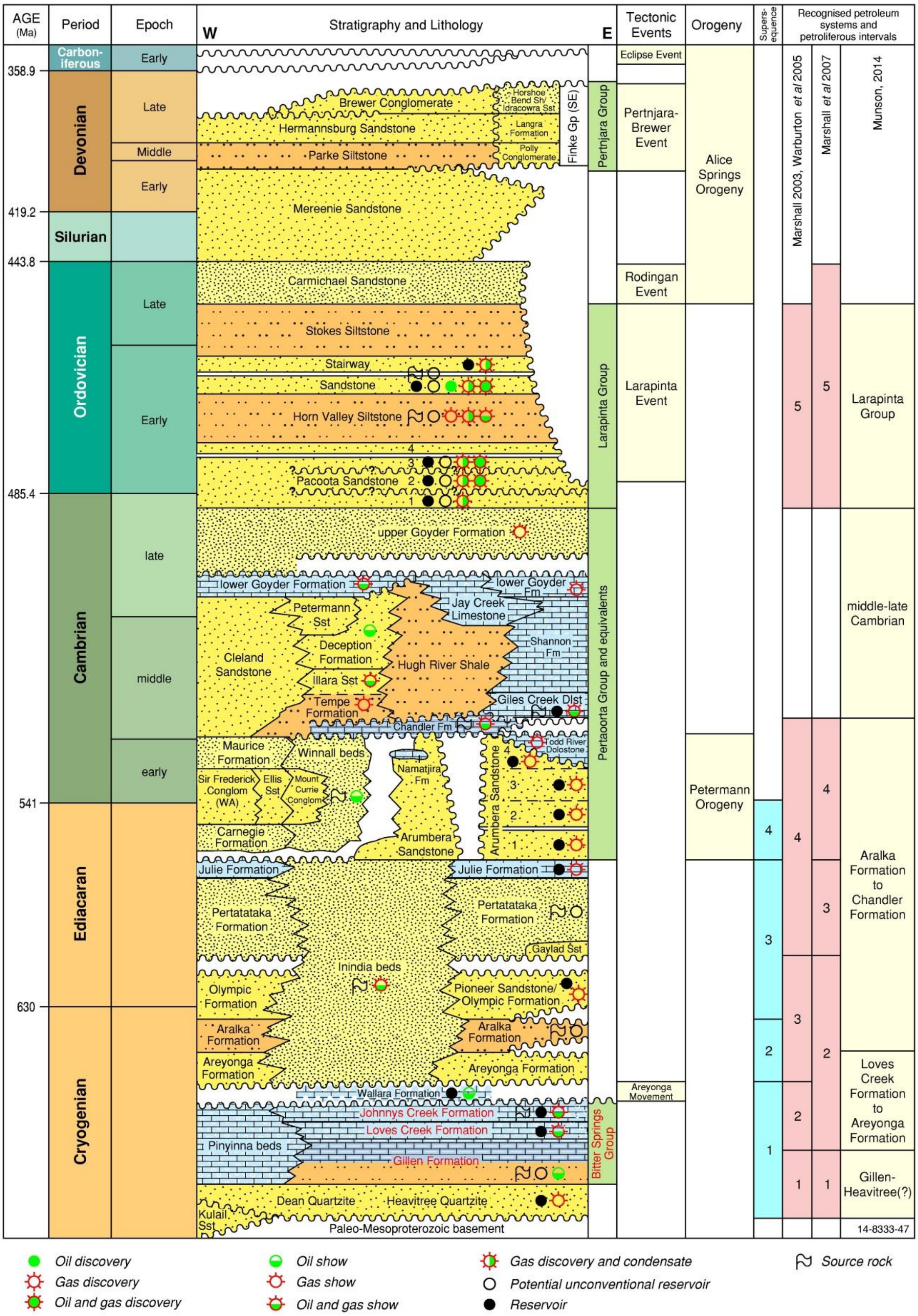

Figure C.2 Lithostratigraphy of the Amadeus Basin (from Carr et al. (2016); modified from Edgoose (2013), Haines and Allen (2014) and Munson (2014)). Supersequences in the Neoproterozoic follow Walter et al. (1995). Chart also shows locations of key source rocks, reservoirs and hydrocarbon discoveries and shows in the basin. Geological time scale on left hand side is not to scale.

C.1.2 Petroleum data coverage

Petroleum exploration drilling has been concentrated in the northern part of the basin (Figure C.3; NTGS, 2017a). To date, 38 exploration wells have yielded four oil and/or gas discoveries and five technical gas discoveries that flowed gas to surface on drill-stem testing but are not producing wells. At least 13 exploration wells were drilled off-structure, and cannot be considered as valid tests (Warburton et al., 2005).

12,986 km of 2D seismic data has been acquired in the basin (Figure C.3), mostly in the northern part of the basin in the region surrounding the Mereenie and Palm Valley fields. These data range in vintage from early 1960s to 2013 (Carr et al., 2016; NTGS, 2017b).

Away from the producing fields, large areas of the basin remain underexplored and data distribution is very sparse. In particular, no wells have been drilled in the western part of the basin, in Western Australia.

There is an almost complete coverage of gravity data across the basin with a station spacing of 4 km or less. The basin is covered by airborne magnetics data at a line spacing of 400 m or less (Carr et al., 2016).

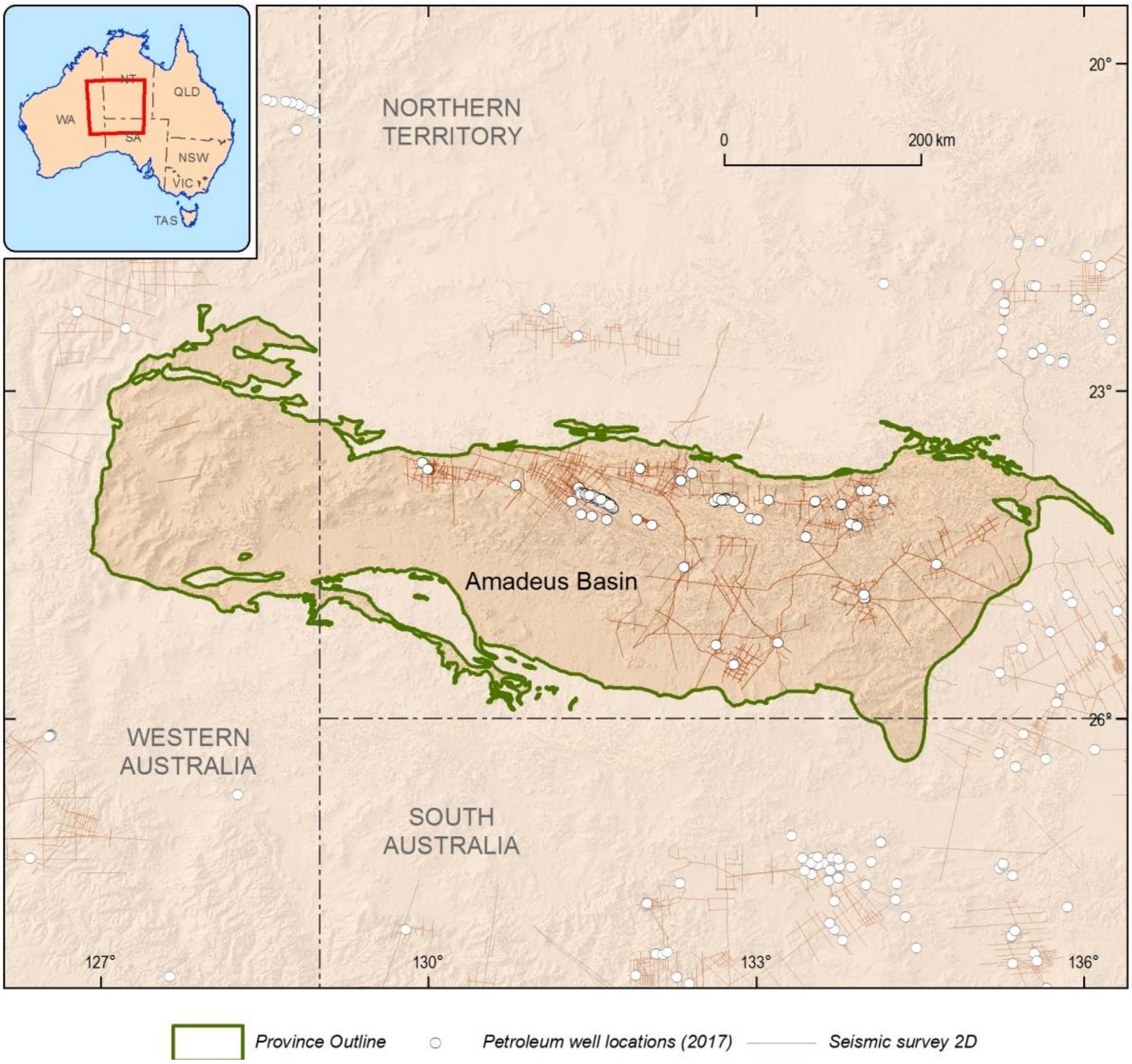

Figure C.3 Location of petroleum exploration wells the Amadeus Basin (NTGS, 2017). Amadeus Basin outline from Stewart et al. (2013). Location of 2D seismic reflection lines updated from compilation in Carr et al. (2016), using NTGS (2017b). Well data from NTGS (2017a).

C.1.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Amadeus Basin is summarised in Table C.1. A number of conventional oil and gas fields are currently producing in the basin. These include the Mereenie oil and gas field and Palm Valley gas field, which have been producing since 1984, the Dingo gas field and the Surprise oil field (Central Petroleum, 2017).

Unconventional exploration interest is currently focused on the upper Cambrian–lower Ordovician lower Larapinta Group (Figure C.2; Table C.2). Fracture stimulation techniques have been used for many years to enable production of gas from lower permeability (tight) reservoirs in the Pacoota and Stairway sandstones associated with the conventional fields (Figure C.4). For example, 30 out of 72 wells in the Mereenie field have been fracture stimulated, and 4 out of 19 wells have been fracture stimulated at Palm Valley (Figure C.5; Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). Despite the history of production from tight reservoirs in conventional wells, no reserves or production data have been reported for tight reservoirs alone.

The potential for a shale gas play in the Horn Valley Siltstone has been recognised (Vu et al., 2011; Central Petroleum, 2017). Central Petroleum is actively investigating the unconventional potential of the Horn Valley Siltstone north of the Mereenie Field (EP115); the formation extends into the gas window over an area of 10,000 km^2, indicating the broad potential extent of this play (Ambrose, 2006; Munson, 2014). The shale gas potential of the Bitter Springs Formation, lower Giles Creek Dolostone, and Goyder Formation have also been assessed (Vu et al., 2011). These formations were determined to be poor gas shale candidates based on the samples available, and hence the shale gas potential of these units requires further investigation. The Shannon, Pertatataka and Aralka formations have also been cited as potential tight/shale gas targets (Munson, 2014).

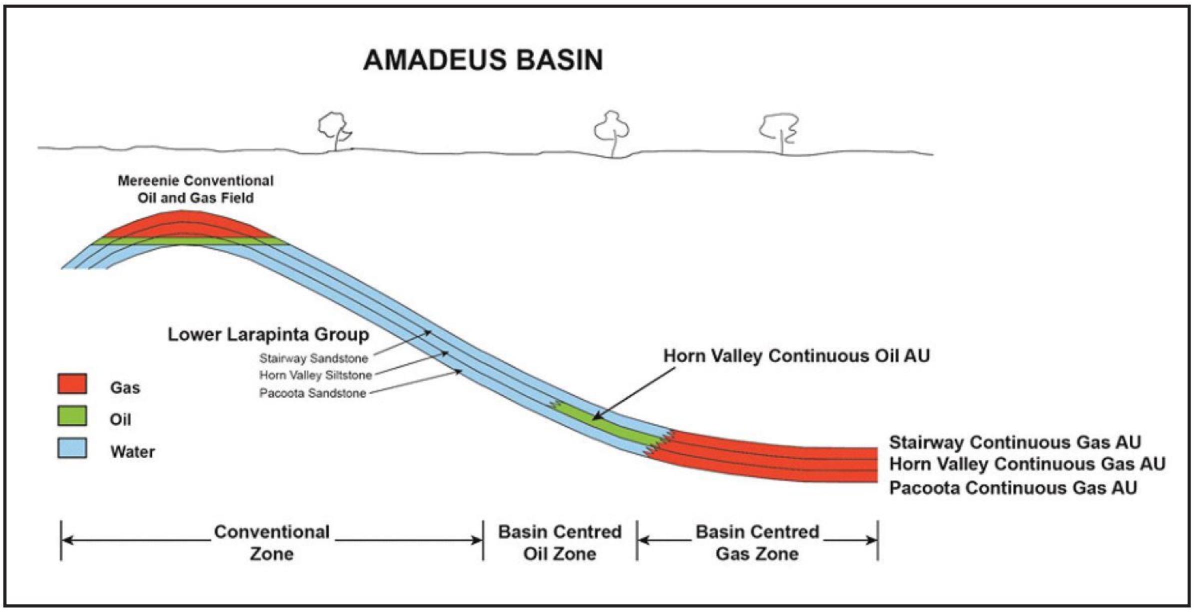

Figure C.4 Cross-section showing unconventional plays of the lower Larapinta Group (Warner et al., 2012).

No contingent shale or tight gas resources have been recorded for the basin, however two regional scale prospective resource estimates have been published for the Amadeus Basin, as described below.

- DSWPET conducted an assessment of the hydrocarbon potential of three continuous gas plays in the lower Larapinta Group (Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone; Figure C.4) estimating a total mean prospective technically recoverable resource of 26.2 Tcf of gas (Table A.3; Table C.1; DSWPET, 2011; Warner et al., 2012; see also AERA, 2018). This includes 11.3 Tcf of Horn Valley Siltstone shale (prospective area 7,395 km^2), 9.8 Tcf of Pacoota Sandstone tight gas (prospective area 3,440 km^2) and 5.1 Tcf of Stairway Sandstone tight gas (prospective area 3,440 km^2).

- AWT have reported their best estimate of resource to be 16 Tcf for the potential shale gas play associated with the Horn Valley Siltstone over a prospective area of 7,267 km^2 (Table C.1; AWT International, 2013).

The Amadeus Basin is highly prospective both for conventional and unconventional oil and gas. However, despite the successful use of fracture stimulation techniques to enhance gas production from existing conventional fields, exploration for both shale and tight gas in the basin is still at a frontier stage. Although the prospective resources reported above highlight the potential significance of shale and tight gas resources in the basin, the uncertainties due to lack of knowledge are considerable. Away from the producing fields, large areas of the basin remain underexplored with sparse data distribution and poorly characterised geology, particularly in the southern and western areas of the basin. As a result, the full extent of shale or tight resources in the basin are still poorly understood and quantified, and estimates of potential resources have a high degree of uncertainty. Significant additional seismic acquisition, drilling and testing is required to resolve the full shale and tight gas resource potential of the basin.

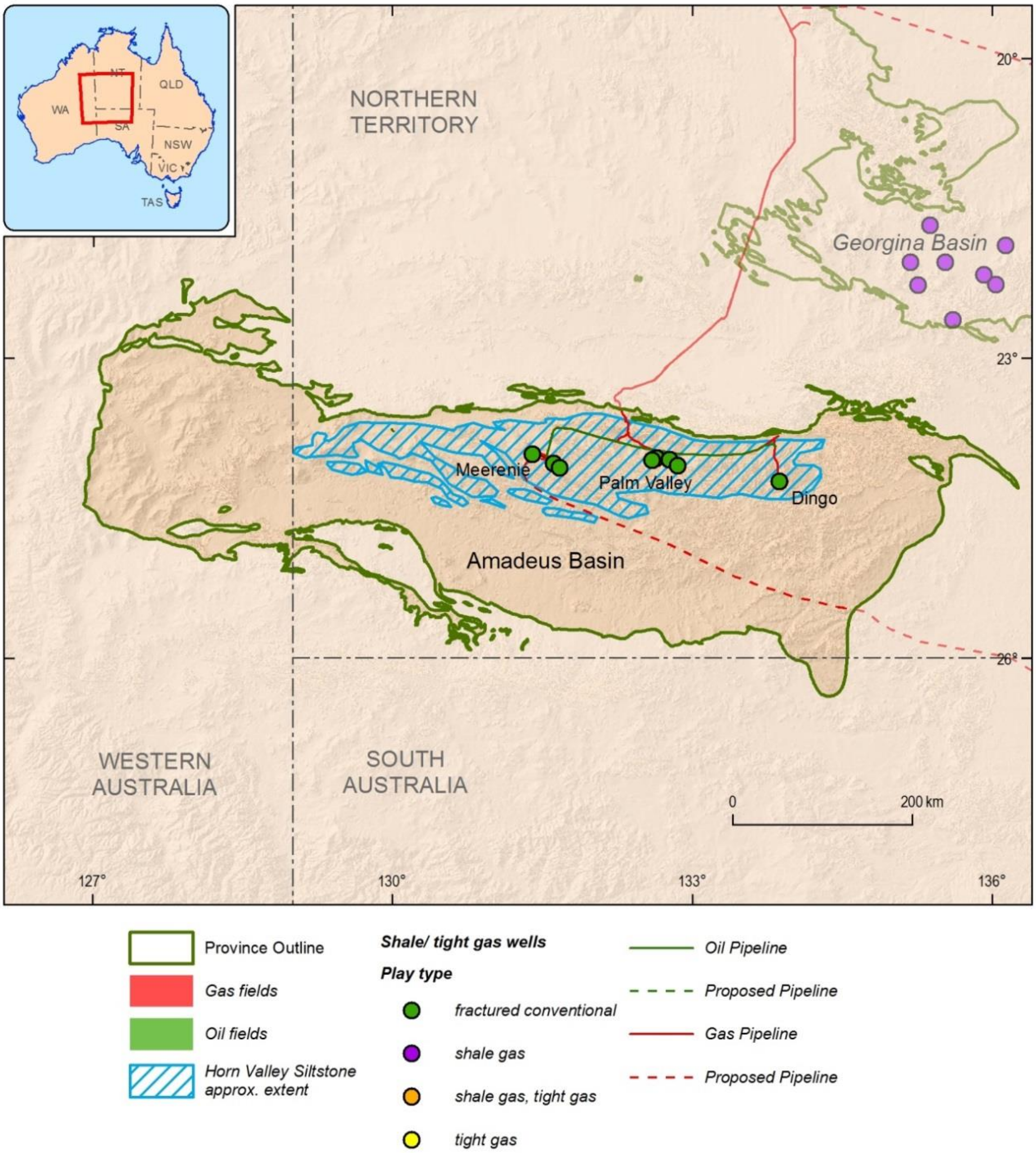

Figure C.5 Producing fields and location of fracture stimulated wells. Approximate extent of the Horn Valley Siltstone is source from Ahmad and Scrimgeour (2013). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.2 Summary of shale and tight gas plays compiled from Munson et al. (2014).

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity	Play type	Exploration status
Stairway Sandstone	Early Ordovician	epicontinental seaway	750–1,800	< 550 m	Some Type III; likely Horn Valley siltstone source	0.02–0.53%	Unknown	Tight gas	?Preliminary exploration (Central Petroleum, 2017)
Horn Valley Siltstone	Early Ordovician	shallow marine	1,000–1,900	0–422 m	Type II; type III	0.2–9.0%	Early oil – gas window	Shale gas	Preliminary exploration (Central Petroleum, 2017)
Pacoota Sandstone	Early Ordovician	outer shelf, estuarine, tidal, barrier island	1,020–2,100	700–800 m	Horn Valley Siltstone	as above	as above	Tight gas	?Preliminary exploration (Central Petroleum, 2017)

C.1.4 Gas market access and infrastructure

The Amadeus Basin currently supplies gas to Australia's Northern Territory Gas Market. Significant existing pipeline infrastructure connects the basin to Darwin (AER, 2017). The basin is poorly to moderately well serviced in terms of road and rail access, depending on location within the basin.

Figure C.6 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.3.

Table C.3 Summary of social factors, market access and infrastructure. Pipeline information from AER (2017). For further details on gas processing facilities see Central Petroleum (2017).

INFRASTRUCTURE	
Gas market	Currently supplies to the Northern Territory Gas Market
Proximity to gas pipelines	• Amadeus Gas Pipeline (Amadeus Basin to Darwin) – capacity 120 TJ/day • Palm Valley to Alice Springs Pipeline – capacity 27 TJ/day
Gas processing facilities	Mereenie Gas Plant; Palm Valley Gas Plant
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	0 to > 200 km
Road and rail access	Poorly to moderately well serviced
Approximate development timeframe	8 to >10 years

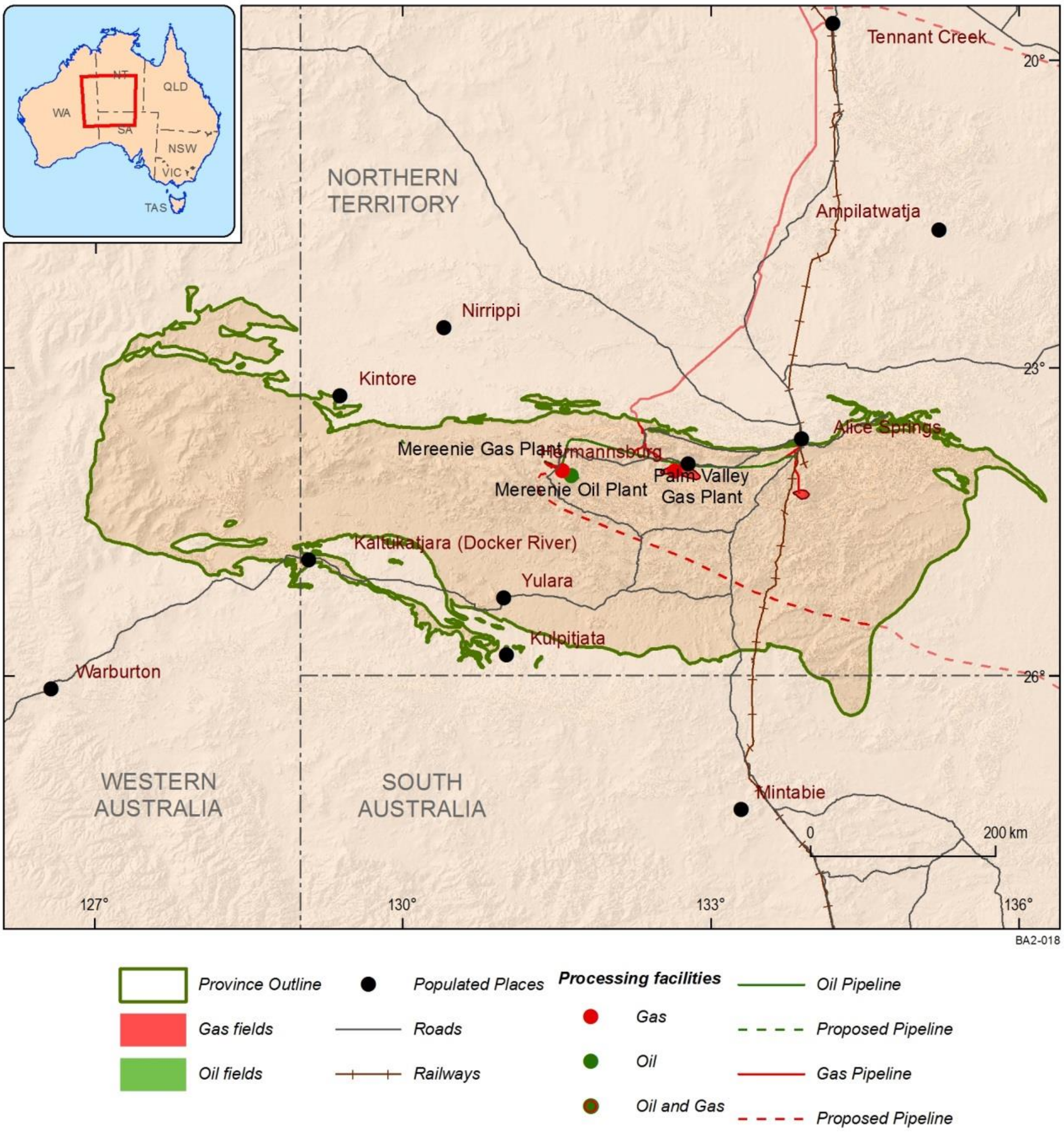

Figure C.6 Infrastructure, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

C.1.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia.

In September 2017, the Western Australian government implemented a moratorium on the use of hydraulic fracturing while an inquiry into the practice is undertaken. In 2016, the Northern Territory Government implemented a moratorium on unconventional onshore gas activities in the territory, while an inquiry was undertaken and pending the Government's decision on the recommendations of the inquiry; the final report of the inquiry was released in March 2018 (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). Details of the moratorium and regulatory restrictions are described below.

C.1.5.1 Northern Territory

In April 2018, the Northern Territory Government accepted all 135 recommendations of the inquiry and lifted the moratorium on hydraulic fracturing over 51% of the Territory. An implementation plan to be released in July 2018 will clearly show how the recommendations will be implemented.

C.1.5.2 Western Australia

The future of fracking will be decided following an independent scientific inquiry (Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia, 2017).

C.1.6 Hydrogeology and groundwater

C.1.6.1 Groundwater systems

In addition to the petroleum resources, the Amadeus Basin also hosts groundwater. Topographically, the basin is generally flat with Cenozoic (Paleogene, Neogene and Quaternary) alluvial sediments overlying synclinal structures (MacQueen and Knott, 1982) (Figure C.7). There are two broad hydrogeological zones within the Amadeus Basin: the southern zone, with intensely folded and fractured rocks discharging to a string of playas; and a northern zone of broad folds bounded to the north by the MacDonnell Ranges and to the south by the George Gill Range (Lau and Jacobson, 1991). The depth to standing water level (SWL) ranges from deeper than 150 m in the Roe Creek Borefield (pre-development ~100 m) to 40 m close to the Todd River in the Rocky Hill area. There are several aquifers, including the Pacoota, Mereenie and Hermannsburg sandstones. The Mereenie Sandstone is the main aquifer for the Roe Creek Borefield near Alice Springs. Most hydrogeological investigation into the Amadeus Basin has focused in the east, supporting water supply for Alice Springs and surrounding areas; additionally, groundwater resources are used further west for less populated agricultural, community and tourist purposes (Lloyd and Jacobson, 1987; NT DLRM, 2016; Jolly et al., 1994). The following paragraphs present further details about the main aquifers, particularly those of the eastern Amadeus Basin (Hostetler, 2003, 2005). The lithostratigraphy presented above (Figure C.2) indicates the relationships between formations of the Amadeus Basin, including those containing the major aquifers. Figure C.7 presents a geological cross-section of the basin and highlights some of these aquifers.

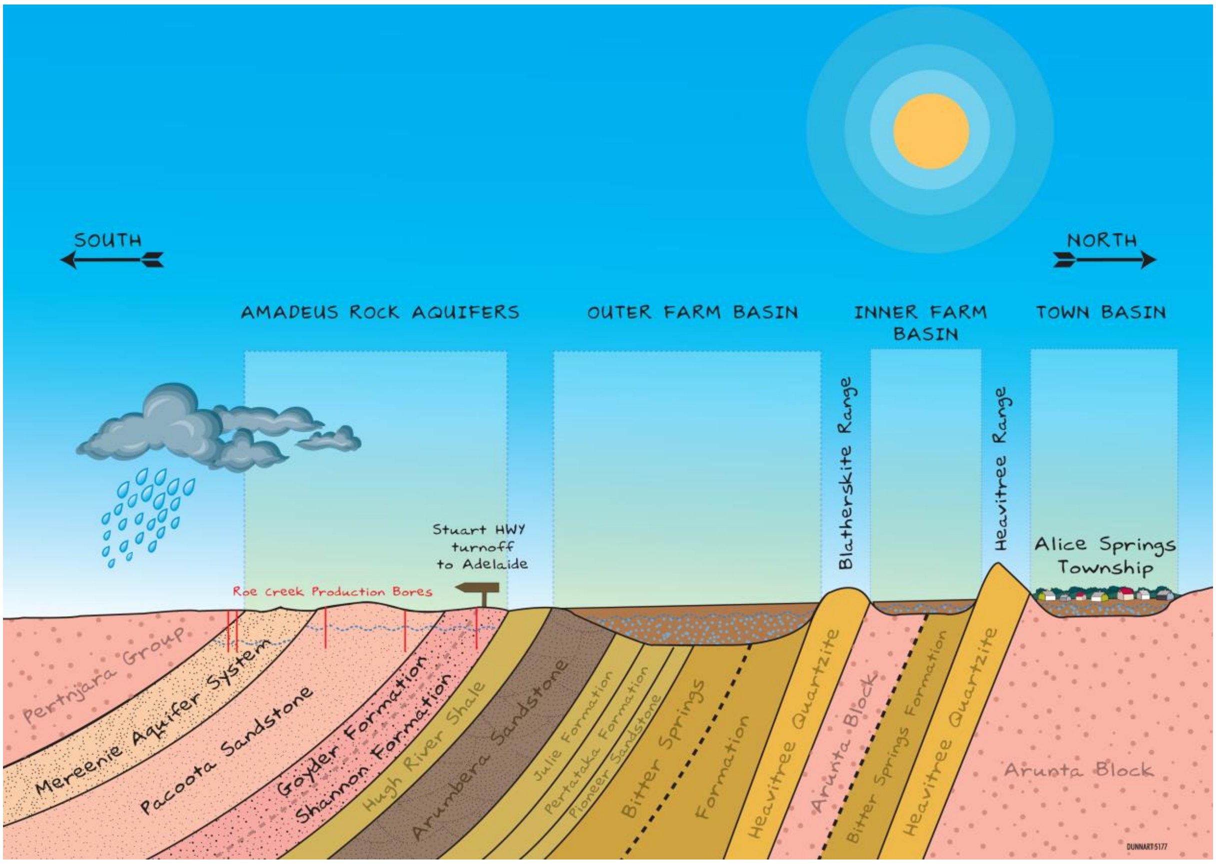

Figure C.7 North-south geological cross section of the Alice Springs Area (NT DLRM, 2016).

Jay Creek Limestone/Shannon Formation (Cambrian)

The Jay Creek Limestone consists of alternating beds of limestone and red brown, micaceous siltstone. Thickness ranges from 150 m to over 1,000 m in the middle of the Waterhouse Anticline, which is associated with the Waterhouse Ranges (MacQueen and Knott, 1982). The Shannon Formation (350 m thick) has a similar lithology.

The Jay Creek Limestone/Shannon Formation is continuous through most of the northeastern Amadeus Basin with a groundwater flow that is generally from west to east.

Goyder Formation (Cambrian)

The Goyder Formation (300 m thick) crops out along the base of the MacDonnell Ranges. It conformably overlies the Jay Creek Limestone and consists of alternating sandstone and siltstone beds (MacQueen and Knott, 1982). Groundwater flow regionally is from west to east, although in the vicinity of Roe Creek it is towards the borefield, with a depth to water table of 90 m. The regional transmissivity of the Goyder Formation is approximately 150 m^2/day, although near the Roe Creek Borefield it is up to 580 m^2/day (MacQueen and Knott, 1982).

Pacoota Sandstone (Cambrian–Ordovician)

The Pacoota Sandstone, which conformably overlies the Goyder Formation, ranges in thickness from 350–450 m and is a highly productive aquifer, with typically low salinity (500-1,000 mg/L TDS). It is of particular importance for water resources in the Kings Canyon area, as well as close to Alice Springs. The Pacoota Sandstone and underlying Goyder Formation have a hydraulic connection, but distinct chemistry. The Horn Valley Siltstone (which is assumed to have no aquifer potential) overlies the Pacoota Sandstone in most of the basin. In the east, the Mereenie Sandstone directly overlies the Pacoota Sandstone, but there appears to be little connection between these aquifers. Regional groundwater flow in the Pacoota Sandstone is generally from west to east. However, near the Roe Creek Borefield, heavy pumping has increased the hydraulic gradient (MacQueen and Knott, 1982; Lloyd and Jacobson, 1987; Jacobson et al., 1989; Read, 2004; Jolly et al., 1994).

Mereenie Sandstone (Silurian–Devonian)

The Mereenie Sandstone (365 m thick) is, by an order of magnitude, the most highly developed aquifer in the Amadeus Basin. It occupies an area of about 27,000 km^2 within the extent of the Amadeus Basin, although it has been eroded north of the Waterhouse Ranges (MacQueen and Knott, 1982). It was deposited in a marginal marine to aeolian environment and is commonly divided into three sub-units.

- **Unit A** was deposited in a marginal marine environment and consists of sandstone with siltstone interbeds.
- **Unit B** is about 100 m thick and consists of a cross-bedded, pure quartz sandstone.
- **Unit C** is about 115 m thick and consists of a well-cemented orange brown coloured sandstone.

Units A and C are the highest yielding sub-units in the Mereenie Sandstone. Unit B is generally not used because the lack of cementation can cause bore failure (Jolly et al., 1994). Primary permeability in the Mereenie Sandstone is controlled by the percentage and type of lithic content in the sandstone. Permeability is highest in Unit B, but iron cementation in Unit C, has enabled fracture induced secondary permeability west of Roe Creek (Lau, 1989). There seems to be limited connection between the Mereenie Sandstone and underlying or overlying aquifers (Jolly et al., 1994).

Hermannsburg Formation (Devonian)

The Hermannsburg Sandstone (600 m thick) unconformably overlies the Mereenie Sandstone over most of the eastern Amadeus Basin, except north of the Waterhouse Ranges where it lies directly on the Pacoota Sandstone. The Hermannsburg Sandstone consists of red-brown, poorly sorted, silty sandstone with interbeds of micaceous siltstone. In the Alice Springs region, it is often difficult to distinguish it from the Mereenie Sandstone in drillers' logs (MacQueen and Knott, 1982).

It is generally low yielding (1 L/s) and is only used for small volume community supplies.

Cenozoic Sediments

Alluvial and aeolian Paleogene, Neogene and Quaternary sediments overlie most of the Amadeus Basin, obscuring the broad synclinal folds of the basin. They are generally shallow (20 m) and heterogenous, except where the Todd River/Roe Creek system has formed small sedimentary basins such as the Town Basin and the Inner and Outer Farms basins. These basins were the initial source of water for Alice Springs, and combined with rock pools in the river, were originally utilised by the Arunta people (MacQueen and Knott, 1982). After the establishment of the Roe Creek Borefield, use of these aquifers shifted to maintenance of local parks and some small-scale agriculture.

Recharge in the Town Basin is from the Todd River and the over-irrigation of lawns and gardens. Depth to SWL is approximately 5 m in the Town Basin, and 20 m in the Farm Basin, with a transmissivity of about 1,000 m^2/day.

In other parts of the Amadeus Basin region, such as communities further west and the tourist town of Yulara, groundwater is the only source of water. It is typically derived from palaeovalley sediments. For example, at Yulara and the Uluru–Kata Tjuta National Park, about 750 ML/yr is extracted from the Dune Plains Palaeovalley aquifer (English et al., 2012). Palaeovalley aquifers host groundwater ranging from modern to 7,000 years old. The palaeovalley around Uluru–Kata Tjuta is about 100 m thick, with the water table at about 12–25 m below ground surface (Parks Australia, 2015).

C.1.6.2 Groundwater quality

Currently good quality groundwater (between 500–1,000 mg/L total dissolved solids; TDS) is extracted from the Mereenie Aquifer System for town supply; however not all groundwater in this aquifer is good quality. Water quality deteriorates with depth in the Roe Creek Borefield and ranges from 600–2300 mg/L TDS (MacQueen and Knott, 1982). Salinity in the Pacoota Sandstone ranges from 500–1,000 mg/L TDS, freshening where Roe Creek flows over the Pacoota Sandstone in subcrop (MacQueen and Knott, 1982). The groundwater tends to be Ca-Mg-Na-HCO_3-Cl in composition, and is less enriched in Na than the Mereenie Sandstone. Salinity in Cenozoic alluvial and aeolian sediments tends to increase from 500 mg/L TDS in the north to 4,000 mg/L TDS in the south, approaching Heavitree Gap (Evans, 1998). Limited information on groundwater quality is available for the other aquifers.

Modern and Holocene groundwaters (0–5,000 years B.P.) are found in the unconfined calcrete and sand dune aquifers. Other Holocene groundwaters (3–10,000 years B.P.) have been dated in areas of river bed recharge. Groundwater sampled in rocks of the basin has a low modern ^{14}C content and was recharged in the Holocene and late Pleistocene (12–32,000 years B.P.).

C.1.6.3 Groundwater flow

Within the Amadeus Basin, groundwater flow is generally from west to east, although in the middle of the basin a zone of stagnant water is thought to exist. In the vicinity of heavily-pumped borefields, such as the Roe Creek Borefield, these flowpaths are altered to be towards the extractive bores (Cresswell et al., 1999; MacQueen and Knott, 1982). Groundwater flow in the northern Amadeus Basin is through the extensive aquifers and mostly parallel to stratigraphy, although there is hydraulic connection between adjacent aquifers. Further south, the basin is structurally segmented and fractured to limit regional patterns and produce local aquifers instead (Lloyd and Jacobson, 1987).

While there is limited information, the basin is a hydrogeologically complex region. Groundwater has been episodically recharged by three important mechanisms: direct infiltration of rainwater through sand dune cover, fissures in calcrete, and joints in bedrock outcrops.

C.1.6.4 Groundwater planning and use

There are six management zones under the Alice Springs Water Allocation Plan 2016–2026 (NT DLRM, 2016). This plan is focused on the resources of the Alluvial Aquifers and the Amadeus Basin Aquifers. These aquifers are considered to be a non-renewable resource.

Most of Alice Springs' potable water supply is from the Amadeus Basin, especially the Mereenie Sandstone; additional supply is also taken from the Cenozoic palaeovalley sediments of the Town Basin (English et al., 2012). The Alice Springs Borefield is several hundred meters in depth and draws from the Mereenie Sandstone, the Pacoota Sandstone and the Shannon and Goyder formations.

Thirty years of heavy pumping in the Mereenie Sandstone has lowered the standing water level in the aquifer by over 50 m, and has reversed the regional hydraulic gradient as far away as Rocky Hill. The regional hydraulic conductivity within the Mereenie Sandstone is 0.08 m/day (transmissivity 600 m^2/day), while west of Roe Creek, the Mereenie Sandstone is highly fractured, with a hydraulic conductivity up to 500 m/day in high yielding zones (Transmissivity 4,000–6,000 m^2/day) (Jolly et al., 1994). Modern groundwater recharge is limited, implying that projected large-scale groundwater development in this region will use an effectively non-renewable resource (Power and Water Corporation, 2016).

Usage includes licensed extraction of up to 1000 ML/year for agriculture, and 5 ML/year for industry. Unlicensed stock and domestic extractions are estimated to total 87ML/year.

The table below presents information from the NGIS (BoM, 2016) showing summary information of registered bores in the basin (Table C.4).

Table C.4 Information on groundwater bores and water use in and above the Amadeus Basin.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	3,712 (0.02)	
Purposes of registered bores (Top 5, number)	Stock	3,545
	Unknown	28
	Agriculture	22
	Exploration	20
	Monitoring	20
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 13.4 Median: 61 90th Percentile: 182.8	

C.1.7 Surface water systems and hydrology

The Amadeus Basin is overlain by parts of various river catchments. These are the Diamantina–Georgina, De Grey, Sandy Desert, Gardiner, Nullabor and Victoria–Wiso catchments (BoM, 2014) and are presented in Figure B.11. In this arid environment, the surface waters of the region are both ephemeral and unreliable. The main watercourses are the Finke and Todd rivers, which have multiple tributaries flowing through and past the MacDonnell, James and Krichauff ranges.

A string of groundwater discharge plays from a series of salt lakes, including Lake Hopkins in Western Australia and Lake Neale and Lake Amadeus in the Northern Territory. Like the other lakes, Lake Amadeus is usually dry, and captures some water from infrequent rainstorms and when full, flows into the Finke River.

C.1.7.1 Surface water systems

Outside the Diamantina–Georgina catchment, there are very few mapped watercourses. In the Diamantina–Georgina catchment, much of the regional ephemeral surface water flows generally to the south east towards the Simpson Desert, where it dries up. The river water courses are dry for most of the time, flowing on average for 15 days per year. There are a range of salt lake wetlands and semi-permanent water bodies across the region, most of them found in gaps between ranges.

C.1.7.2 Surface water quality

There is an absence of surface water quality data for the region.

C.1.7.3 Surface water flow

Regionally there is little consistent information on surface water flows with the exception of the area around Alice Springs. Here stream records have been collected for the Todd River and a number of its tributaries since the 1960s. River height records confirm the highly episodic nature of surface water flow within the district.

C.1.7.4 Surface water planning and use

There is limited surface water use in the region: approximately 95% of the water supply for the local communities comes from groundwater. Apart from a few ephemeral water holes in the region, there are no surface storages in the region for water supply. The rules and trading of licences are provided by the Water Act 1992 (NT) (Northern Territory Legislation, 1992). Further rules for the granting of licences and for the trading of licensed allocations (for water which has not been allocated for public water supply) are set out in detail in the management plan (NT DLRM, 2016).

C.1.8 Groundwater–surface water interactions

The groundwater and surface water systems in the eastern part of the Amadeus Basin are interconnected, but less is known of the western region. In the east, episodic flows of the Todd River recharge the Alice Springs Town Basin and the Inner and Outer Farm basins (Figure C.7). Flows in the Roe River recharge the Wanngardi Basin, and to a lesser extent, the Mereenie aquifer.

C.1.9 Other environmental factors

Within the Amadeus Basin there are 52 km^2 of Listed Nationally Important Wetlands, 1,600 km^2 of Potential Groundwater Dependant Ecosystems, and a total of 5,111 km^2 of protected areas (such as national parks) are listed; there are no Ramsar wetlands (Table C.5).

Table C.5 Environmental Assets within the Amadeus Basin

Environmental Assets		
Ramsar Wetlands	None	
Nationally Important Wetlands Top 5 by area (area km²)	Karinga Creek Paleodrainage System	49
	Lake Amadeus	3
	Rock Pools of the Walter James Range	< 1
	Finke River Headwater Gorges System	< 1
	—	0
	TOTAL AREA	52
Protected areas (CAPAD 2016) Top 5 by area (area km²)	National Park	2,151
	Other Conservation Area	1,547
	National Park (Commonwealth)	1,201
	Nature Park	94
	Conservation Reserve	82
	TOTAL PROTECTED AREA	5,111
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km²).	1600	

C.1.10 Social Considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in Table C.6. Although Alice Springs is located outside the basin extent, its proximity to the basin means that its water supply is derived from Amadeus Basin groundwater (NT DLRM, 2016; Jolly et al., 1994).

Table C.6 Social and general characteristics of the Amadeus Basin region.

GENERAL CHARACTERISTICS		
Population	8198	
Major population centres (Top two)	Yulara, Hermannsburg	
Land use types Top 5 by area (area km²)	Other Protected areas	107,775
	Grazing native vegetation	69,024
	Nature Conservation	3,160
	Minimal use	1,031
	Urban intensive uses	387
Aboriginal Protected Area (CAPAD 2016) and Native title (area km²)	53,776	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

AERA (Australian Energy Resources Assessment) (2018) Australian Energy Resources Assessment interim report, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.ga.gov.au/aera>.

Ahmad M and Scrimgeour IR (2013) Geological framework: in Ahmad M and Munson TJ (compilers) 'Geology and mineral resources of the Northern Territory.' Northern Territory Geological Survey, Special Publication 5.

Ambrose GJ (2006) The Amadeus Basin 2006. In: Northern Territory of Australia, onshore hydrocarbon potential 2006. Northern Territory Geological Survey, Record, 2006–003, 19 pp.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric ("Geofabric"), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

CAPAD (2016) Collaborative Australian Protected Area database. Department of Environment and Energy. Viewed 07/07/2017, <http://www.environment.gov.au/land/nrs/science/capad/2016>.

Carr LK, Korsch RJ, Palu TJ and Reese B (2016) Onshore Basin Inventory: the McArthur, South Nicholson, Georgina, Wiso, Amadeus, Warburton, Cooper and Galilee basins, central Australia. Record 2016/04. Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/Record.2016.004>.

Central Petroleum (2017) Amadeus Basin. Viewed 16/01/2018, <http://centralpetroleum.com.au/our-business/our-licence-areas/amadeus/mereenie-oil-and-gas-field-ol4-ol5/>.

Cresswell RG, Jacobson G, Wischusen J, and Fifield LK (1999) Ancient groundwaters in the Amadeus Basin, Central Australia: evidence from the radio-isotope 36Cl., Journal of Hydrology, v 223 (1999), pp. 212-220

DSWPET (2011) Unconventional reservoir resource assessment for the lower Larapinta Group Amadeus Basin. Central Petroleum Ltd, ASX Announcement, 7 February 2011.

Edgoose CJ (2013) Chapter 23: Amadeus Basin. In: Ahmad, M and Munson, TJ (Compilers), Geology and mineral resources of the Northern Territory. Northern Territory Geological Survey, Special Publication, 5, 23:1-23:70.

Edgoose CJ, Scrimgeour IR and Close DF (2004) Geology of the Musgrave Block, Northern Territory. Northern Territory Geological Survey, Report, 15, 44 pp.

English P, Lewis S, Bell J, Wischusen J, Woodgate J, Bastrakov E, Macphail M and Kilgour P (2012) Water for Australia's arid zone – identifying and assessing Australia's palaeovalley groundwater resources: summary report. Waterlines Report Series No 86, August 2012. National Water Commission, Canberra.

Evans D (1998) Alice Springs Town Basin Monitoring Review 1996-1997, Northern Territory Department of Lands, Planning, and Environment Report No. 43/1997A

Flöttmann T and Hand M (1999) Folded basement cored tectonic wedges along the northern edge of the Amadeus Basin, central Australia: evaluation of orogenic shortening. Journal of Structural Geology, 21, 399–412.

Flöttmann T, Hand M, Close DF, Edgoose CJ and Scrimgeour IR (2004) Thrust tectonic styles of the intracratonic Alice Springs and Petermann orogenies, central Australia. In: McClay KR (ed.), Thrust tectonics and hydrocarbon systems. American Association of Petroleum Geologists, Memoir, 82, pp. 538–557.

Forman DJ (1966) The geology of the south-western margin of the Amadeus Basin, central Australia. Bureau of Mineral Resources, Report 87, 54 pp.

Forman DJ (1971) The Arltunga Nappe Complex, MacDonnell Ranges, Northern Territory, Australia. Journal of the Geological Society of Australia, 18(2), 173–182.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Haines PW and Allen HJ (2014) Geology of the Boord Ridges and Gordon Hills: key stratigraphic section in the western Amadeus Basin, Western Australia: Geological Survey of Western Australia, Record, 2014/11, 21 pp.

Haines PW, Hand M and Sandiford M (2001) Palaeozoic synorogenic sedimentation in central and northern Australia: A review of distribution and timing with implications for the evolution of intracontinental orogens. Australian Journal of Earth Sciences, 48(6), 911–928, DOI: 10.1046/j.1440-0952.2001.00909.

Hostetler S (2003) Radioisotope concentrations of stratified Amadeus Basin aquifers at Alice Springs, Central Australia. Extended Abstract in the proceedings of "Isotopic Assessment of Long Term Groundwater Exploitation", research coordination meeting, Vienna, 12-16 May 2003. International Atomic Energy Agency. Published October 2006, IAEA-TECDOC-1507.

Hostetler S (2005) Radioisotope Concentrations of Stratified Amadeus Basin Aquifers at Alice Springs, Central Australia. Final Report for the CRP on Response of Hydrological Systems to Long-Term Exploitation. Bureau of Rural Sciences, Agriculture, Fisheries and Forestry Australia. Unpublished report.

Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia (2017) Viewed 18/01/2017, <https://frackinginquiry.wa.gov.au/>.

Jacobson G, Lau GC, McDonald PS, Jankowski J (1989) Hydrogeology and groundwater resources of the Lake Amadeus and Ayers Rock region, Northern Territory. Bureau of Mineral Resources, Geology and Geophysics, Bulletin 230, 89 pp.

Jolly P, Chin D, Prowse G and Jamieson M (1994) Hydrogeology of the Roe Creek Borefield. Northern Territory Power and water Authority Report No. 10/1994A, 29 pp.

Korsch RJ and Kennard JM (eds) (1991) Geological and geophysical studies in the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 236, 594 pp.

Lau JE (1989) Logging of diamond drill core from Roe Creek Borefield, Alice Springs., NT Power and Water Authority, December 1989

Lau JE and Jacobson G (1991) Aquifer characteristics and groundwater resources of the Amadeus Basin. In: Korsch RJ and Kennard JM (eds) Geological and geophysical studies of the Amadeus Basin. Bureau of Mineral Resources, Australia, Bulletin 236, pp. 563-580.

Lindsay JF and Korsch RJ (1989) Interplay of tectonics and sea-level changes in basin evolution: an example from the intracratonic Amadeus Basin, central Australia. Basin Research, 2, 3–25.

Lindsay JF and Korsch RJ (1991) The evolution of the Amadeus Basin, central Australia. In: Korsch RJ and Kennard JM (eds), Geological and geophysical studies in the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 236, 7–32.

Lloyd JW and Jacobson G (1987) The hydrogeology of the Amadeus Basin, Central Australia. Journal of Hydrology, 93 (1987), 1–24.

MacQueen AD and Knott GG (1982) Groundwater in the north eastern part of the Amadeus Basin. Northern Territory Department of Transport and Works Water Division, Project 32.

Munson TJ (2014) Petroleum geology and potential of the onshore Northern Territory (2014) Northern Territory Geological Survey, Report 22, 242 pp.

Northern Territory Legislation (1992) "Water Act 1992", Act of the Parliament of the Northern Territory, as in force at 1 July 2016. Viewed 29/09/2017, <https://legislation.nt.gov.au/en/Legislation/WATER-ACT>.

NT DLRM (Northern Territory Department of Land Resource Management) (2016) Alice Springs Water Allocation Plan: 2016–2026. Report No. 01/2016A. Northern Territory Government.

NTGS (Northern Territory Geological Survey) (2017a) Geoscience exploration and mining information system (GEMIS) – Petroleum wells. Viewed 11/08/2017, <http://www.geoscience.nt.gov.au/gemis/ntgsjspui/handle/1/79187>.

NTGS (Northern Territory Geological Survey) (2017b) Northern Territory Statewide Geophysics – Seismic Lines. Viewed 11/08/2017, <http://www.ntlis.nt.gov.au/metadata/export_data?type=html&metadata_id=FB25348A02CB16B2E040CD9B2144584B>.

Oaks RQ Jr, Deckelman JA, Conrad KT, Hamp LP, Phillips JO and Stewart AJ (1991) Sedimentation and tectonics in the northeastern and central Amadeus Basin, central Australia. In: Korsch RJ and Kennard JM (eds), Geological and geophysical studies in the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 236, 73–90.

Parks Australia (2015) Fact Sheet, Geology, Uluru–Kata Tjuta National Park. Viewed 15/12/2017, <http://www.environment.gov.au/resource/geology-uluru-kata-tjuta-national-park>.

Power and Water Corporation (2016) Mereenie Aquifer Alice Springs: Frequently Asked Questions, Community and education. Viewed 15/12/2017, <https://www.powerwater.com.au/community_and_education/mereenie_aquifer_alice_springs>.

Raymond OL (Coordinator) (2009) Surface geology of Australia 1:1 million scale digital geology data: Geoscience Australia, Digital Geology Map. Viewed 16/01/2018, <https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=69455>.

Read RE (2004) Investigation of Groundwater Resources at Oak Valley (Mpwelarre Aboriginal Land Trust). Department of Natural Resources, Environment and the Arts, Report No. 38/2004A. October 2004, Alice Springs, 60pp. Northern Territory Government.

Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Final Report, March 2018. Viewed 23/04/2018, <https://frackinginquiry.nt.gov.au/inquiry-reports?a=494286>.

Shaw RD, Etheridge MA and Lambeck K (1991) Development of the Late Proterozoic to Mid-Paleozoic, intracratonic Amadeus Basin in central Australia: a key to understanding tectonic forces in plate. Tectonics, 10, 688–721.

Shaw RD, Zeitler PK, McDougall I and Tingate PR (1992) The Palaeozoic history of an unusual thrust belt in central Australia based on Ar–Ar, K–Ar and fission track dating. Journal of the Geological Society of London, 149, 937–954.

Stewart AJ (1967) An interpretation of the structure of the Blatherskite Nappe, Alice Springs, Northern Territory. Journal of the Geological Society of Australia, 14(2), 175–184.

Stewart AJ, Oaks RQ Jr, Deckelman JA and Shaw RD (1991) 'Mesothrust' versus 'megathrust' interpretations of the structure of the northeastern Amadeus Basin, central Australia. In: Korsch RJ and Kennard JM (eds), Geological and geophysical studies in the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 236, 361–383.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Vu TAT, Horsfield B and di Primio R (2011) Gas shale potential of the Amadeus and Georgina basins, Australia: preliminary insights. Geoscience Australia Record, 2011/10, 39 pp. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7893-007c-7506-e044-00144fdd4fa6>.

Walter MR, Veevers JJ, Calver CR and Grey K (1995) Neoproterozoic stratigraphy of the Centralian Superbasin, Australia. Precambrian Research, 73, 173–195.

Warburton J, Murray T and Marshall T (2005) Importance of fault seal and strategic assessment of future petroleum exploration potential of the Amadeus Basin. Northern Territory Geological Survey, Record, 2005-004, 99 pp.

Warner D, Ambrose G and Heugh J (2012) Potential for unconventional plays in the Lower Larapinta Petroleum System of the Amadeus Basin. In: Ambrose GJ and Scott J (eds), Central Australian Basins Symposium III. Petroleum Exploration Society of Australia, Special Publication, 7 pp.

Wellman P (1991) Amadeus Basin, Northern Territory: Structure from gravity and magnetic anomalies. In: Korsch RJ and Kennard JM (eds), Geological and geophysical studies in the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 236, 7–32.

Wells AT, Forman DJ, Ranford LC and Cook PJ (1970) Geology of the Amadeus Basin, central Australia. Bureau of Mineral Resources, Bulletin, 100, 222 pp.

C.2 Bowen Basin

Table C.7 Geology and petroleum prospectivity summary

GENERAL	
Jurisdiction	New South Wales, Queensland
Area	153,690 km2
Maximum basin depth	~12,000 m
Maximum sediment thickness	~10,000 m
Age range	Permian–Triassic
Depositional setting	Marine, deltaic and fluvial
Regional structure	Extensional–foreland basin; large synclinal structure (Taroom Trough) flanked to the west by series of half graben (Denison Trough)
Overlying basin(s)	Surat Basin
EXPLORATION STATUS	
Seismic lines	57,035 km of 2D seismic
Number of petroleum wells	>300
Exploration status – conventional	Producing/mature
Exploration status – coal seam gas	Producing/mature
Exploration status – shale/ tight gas	Preliminary exploration
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Gondwanan)
Prospectivity	High
Conventional discoveries	>100; Moonie oil, Roma Shelf gas, Denison Trough gas, western Bowen gas/oil, Comet Ridge CSG
Hydrocarbon production – total to date	0.94 Tcf cumulative conventional gas production; 1.9 Tcf CSG (includes the overlying Surat Basin; current to 2014; AERA, 2018)
2P Reserves	0.1 Tcf conventional; 40.03 Tcf CSG (includes the overlying Surat Basin; current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	0.1 Tcf conventional; 59.2 Tcf CSG (includes the overlying Surat Basin; current to 2014; AERA, 2018)
Undiscovered resource estimates	Conventional and CSG unknown; see below for shale gas
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Shale gas, tight gas
No. of wells targeting shale/ tight gas plays	Approx. 6
Production – shale/ tight gas	None
2P Reserves – shale/ tight gas	None reported

Remaining resources (reserves + contingent resources) – shale/ tight gas	None reported
Undiscovered resource estimates – shale/ tight gas	Shale gas: 97 Tcf (best estimated recoverable resource over a prospective area of 51,252 km2; Table A.3; AWT International, 2013; AERA, 2018); tight gas unknown
Hydrocarbon shows, tests – shale/ tight gas	Daydream-1, Fantome-1, Tasmania-1 (Nicholls et al., 2015; Hayes et al., 2016)

C.2.1 Basin geology

The Bowen Basin, located in southeastern Queensland and northern New South Wales (Figure C.8), forms the northern part of the Permian–Triassic Bowen-Gunnedah-Sydney basin system in eastern Australia. The basin contains up to 10 km of shallow marine to terrestrial clastic sediments including important coal and petroleum resources. In southern Queensland the Bowen Basin is covered by the Jurassic–Cretaceous Surat Basin, which is up to 2.5 km thick. The main depocentres in the Bowen Basin are the thick, north–south elongate Taroom Trough in the east and the Denison Trough in the west. The basin evolved in a back-arc tectonic setting associated with a convergent plate margin (Korsch and Totterdell, 2009; Draper, 2013).

The Bowen Basin was initiated in the early Permian during a phase of intra-continental rifting that resulted in the development of a series of half graben, particularly in the western part of the basin (Denison Trough), and volcanism in the east. The subsequent period of post-rift thermal subsidence was interrupted in the Late Permian by the onset of rapid subsidence in the Taroom Trough caused by foreland loading related to thrusting and crustal thickening in the New England Orogen to the east. This contractional deformation led to the characteristic asymmetry of the Taroom Trough (Figure C.9).

The complex tectonic history of the basin is reflected in the depositional history (Figure C.10). Detailed descriptions of the evolution and stratigraphy of the basin can be found in Green (1997), Korsch and Totterdell (2009) and Draper (2013). Initial deposition in the extensional depocentres in the west was non-marine and the section is characterised by clastic sediments and coal (Reids Dome Beds); a thick igneous section accumulated in the east at this time. The early post-rift succession in the Denison Trough includes the first marine sediments deposited in the basin (Cattle Creek Formation). An unconformity within the overlying Aldebaran Sandstone marks the onset of foreland loading. The thick succession deposited during the Late Permian foreland loading phase comprises dominantly siliciclastic, fluvial, marginal marine, deltaic and marine sediments and coal measures of the Back Creek and Blackwater groups. By the end of the Permian, much of the basin was covered by peat swamps and the coal seams of the Bandanna Formation, Baralaba Coal Measures and correlatives can be mapped seismically across the Taroom Trough. The Triassic part of the foreland loading phase is represented by the fluvial and lacustrine sediments of the Rewan and Clematis groups, and Moolayember Formation.

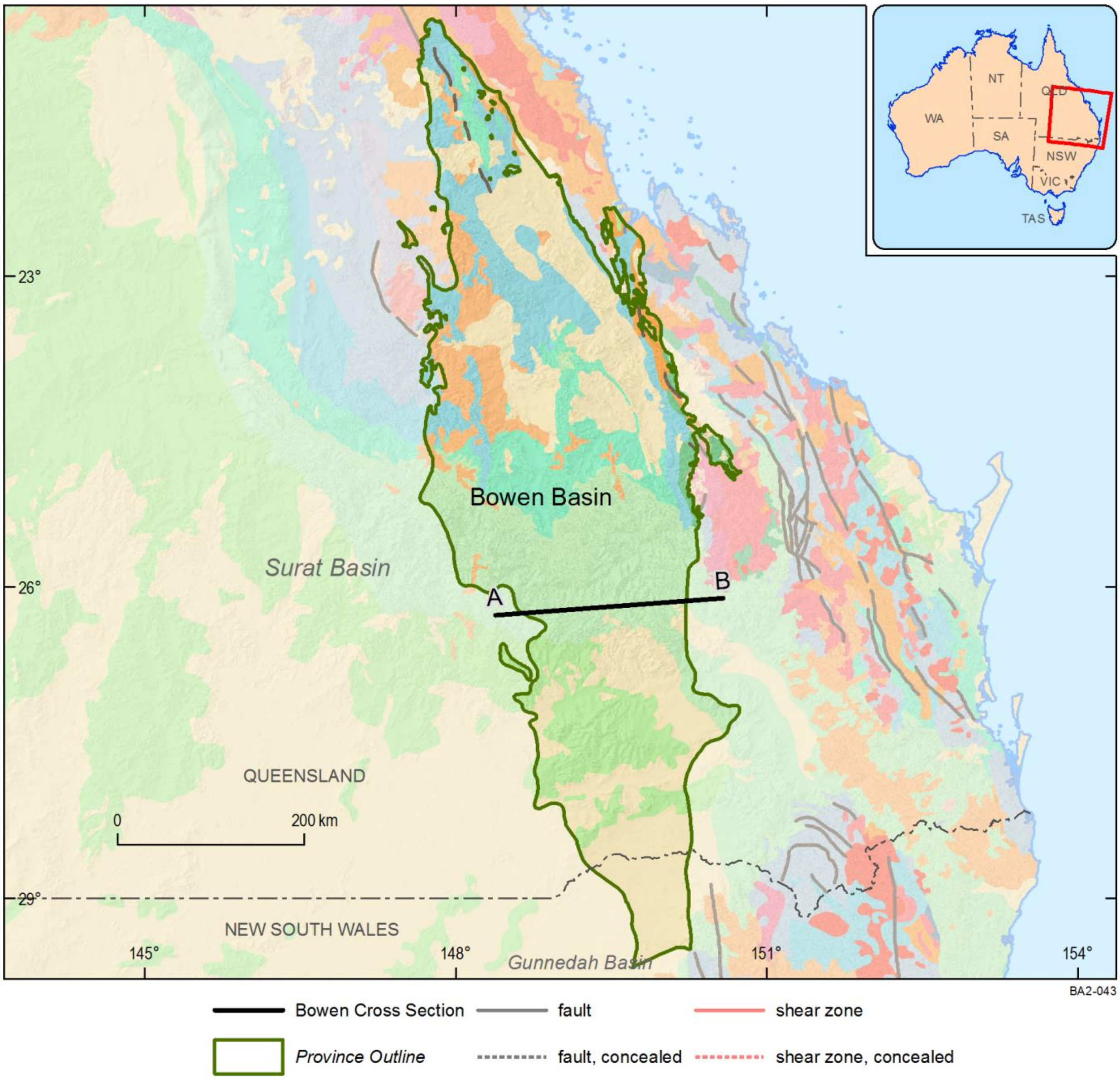

Figure C.8 Location of the Bowen Basin on a base map of 1:2,500,000 scale surface geology (Raymond et al., 2012). Basin outlines from Stewart et al. (2013). Black line shows location of cross-section in Figure C.9.

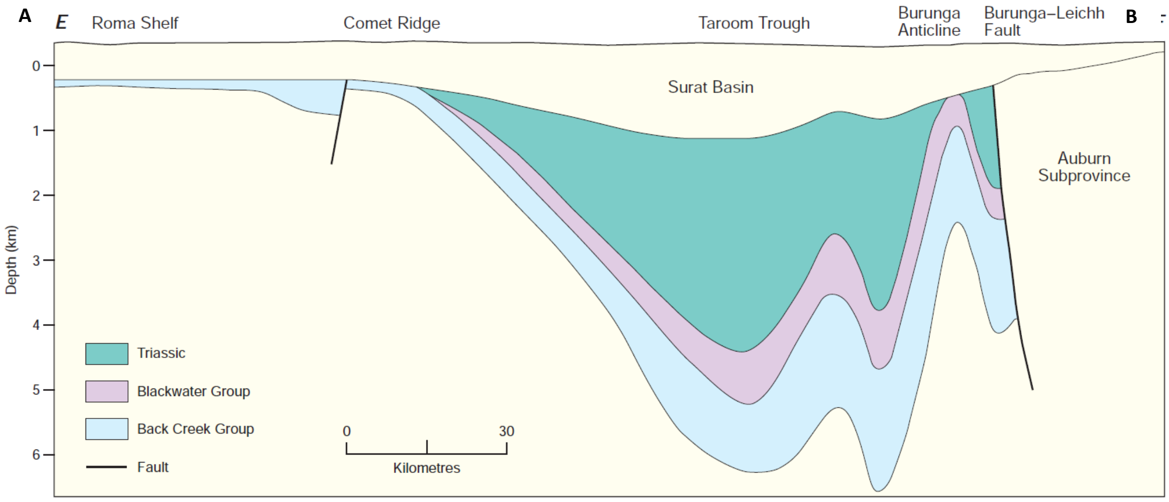

Figure C.9 Schematic cross-section across the central Taroom Trough showing overall synclinal architecture of the trough (Draper, 2013). Location of cross-section shown in Figure C.8.

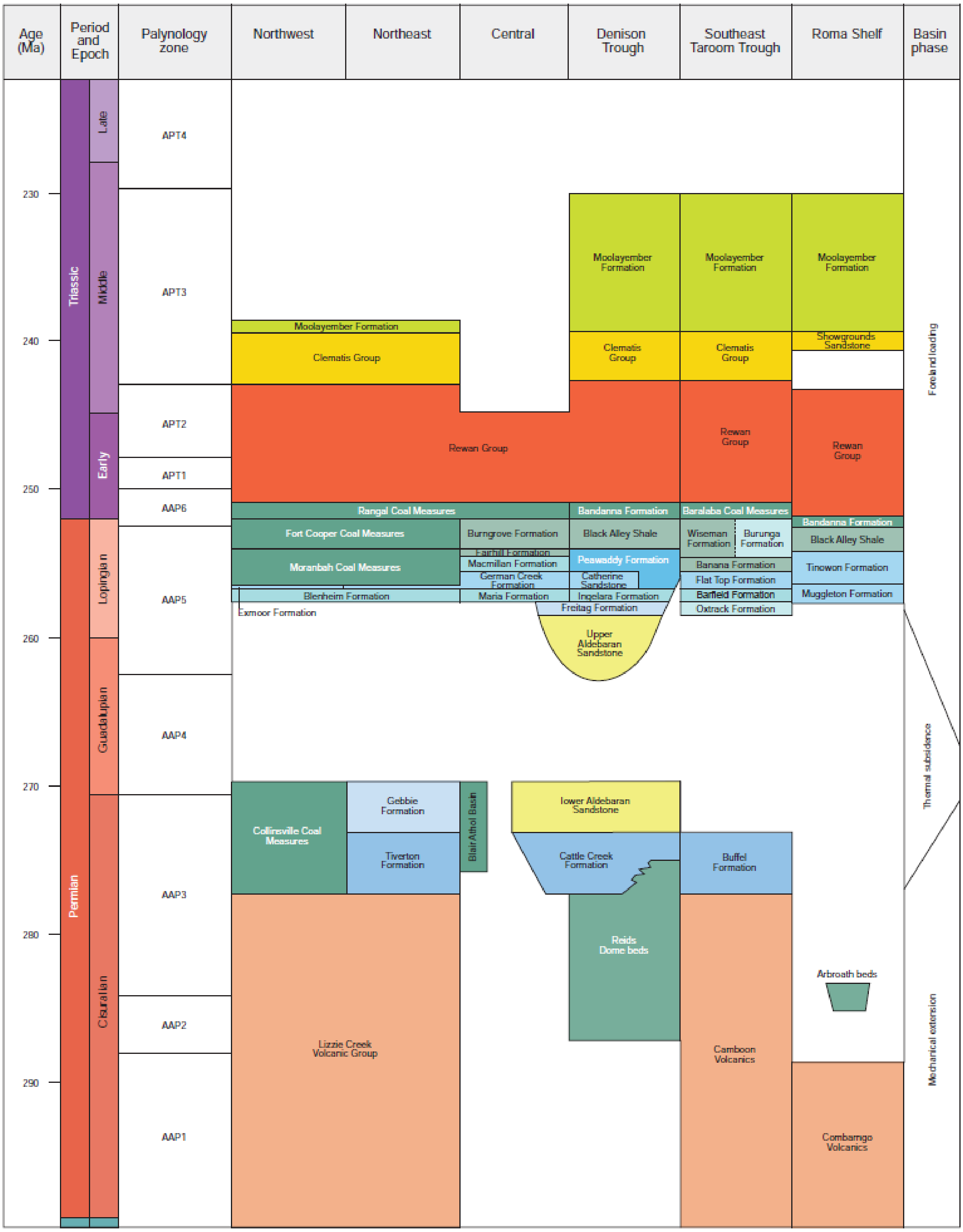

Figure C.10 Bowen Basin stratigraphy (Draper, 2013)

C.2.2 Petroleum data coverage

The Bowen Basin is an established hydrocarbon province. Over 300 wells have been drilled in the basin (Figure C.11; DNRME, 2017a), resulting in more than 100 conventional oil and gas discoveries on the flanks of the basin in structural and stratigraphic accumulations (Hayes et al., 2016). The Moonie oil field on the eastern side of the trough is the largest oil discovery in the basin, while gas has been or is currently produced from numerous fields on the western flank of the Taroom Trough and in the Denison Trough. The basin has a poor–very good coverage of 2D seismic data of varying vintage and limited 3D seismic data sets (Figure C.11; DNRME, 2017b-d).

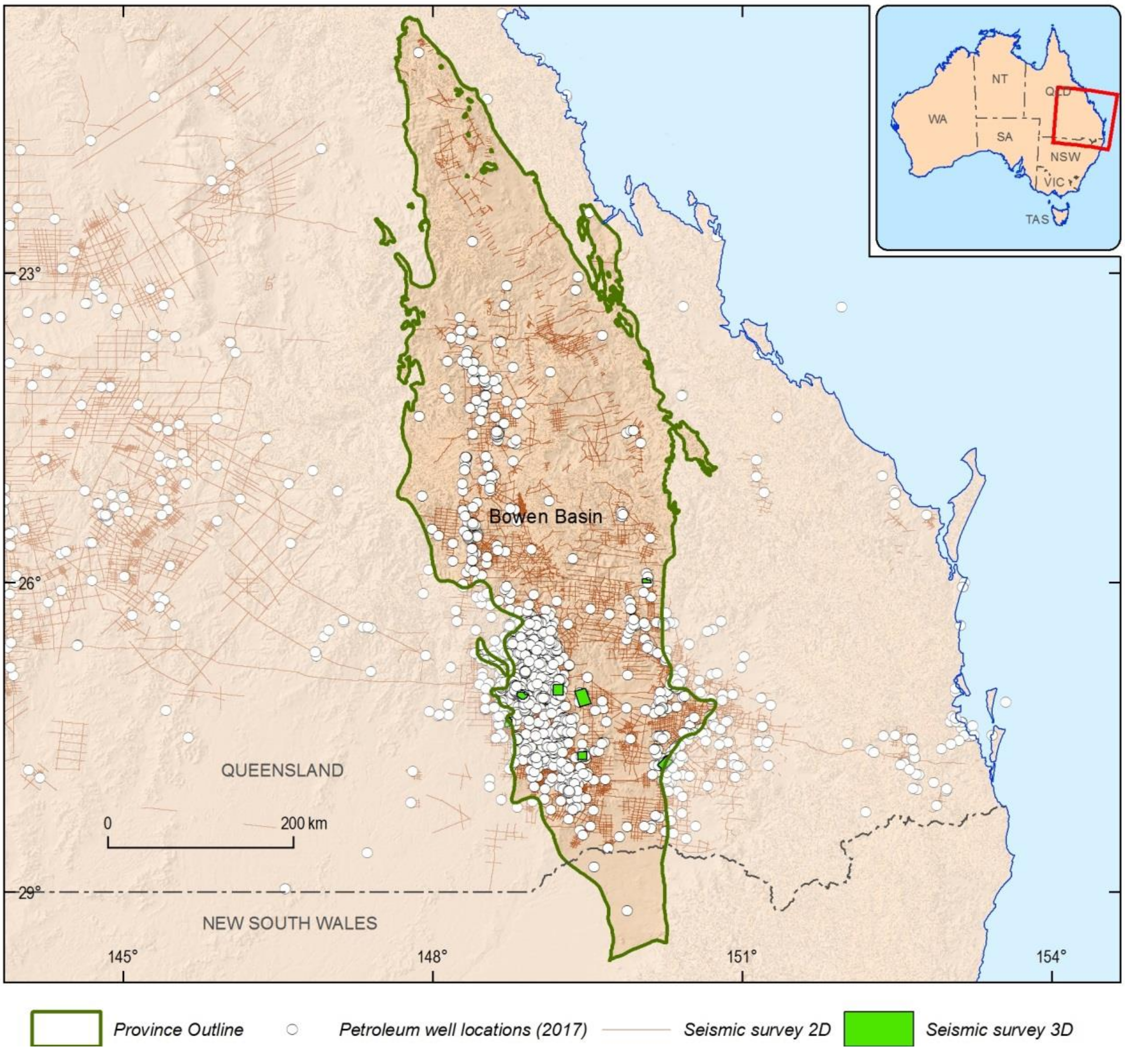

Figure C.11 Location of wells and seismic data, Bowen Basin. Bowen Basin outline from Stewart et al. (2013). Petroleum well data from DNRME (2017a). Seismic data coverage DNRME (2017b-d).

C.2.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Bowen Basin is summarised in Table C.7.

The Bowen Basin succession contains multiple proven and potential source rocks. Geochemical studies have linked oil and gas accumulations in the southern Taroom Trough to coal and associated organic-rich sediments of the uppermost Permian coal measures (including the Bandanna Formation, Baralaba Coal Measures and Kianga Formation), and lacustrine sediments of the Triassic Snake Creek Mudstone (Boreham, 1995; Al Arouri et al., 1998). Both units contain oil and gas-prone Type II/III to Type III kerogens (Al Arouri et al., 1998). Potential source rocks of relevance to shale and tight gas exploration are likely to be present within both coal-rich and marine Late Permian units, particularly the Black Alley Shale (DNRM, 2017b).

Between 2010 and 2015, QGC undertook a tight gas exploration program in the southern Taroom Trough, drilling 6 wells (DNRM, 2017b). The results of the QGC drilling campaign demonstrated that the basin has the necessary ingredients for large basin-centred gas/ liquids resources—thick, low permeability reservoirs, abundant mature source rocks, and anomalous pressures, which commence at depths of 2,500 m (Nicholls et al., 2015; Hayes et al., 2016). However, Hayes et al. (2016) noted that the current well control is inadequate to map prospective fairways with confidence.

Tight gas exploration in the southern Taroom Trough has focused on sandstone units in the Rewan Group, Bandanna Formation and Tinowon Formation. Successful conventional exploration undertaken by Mosaic on the western side of the Taroom Trough (Myall Creek-Churchie area), demonstrated the prospectivity of sands in the Tinowon Formation. The Taroom Trough thickens and deepens to the north (Figure C.12). As a result, basal Rewan sands have been the main target of QGC's northern wells, while towards the south, older formations were the main drilling objectives.

The key shale gas target in the southern Taroom Trough is the Black Alley Shale. Prospective shale gas resources from the Black Alley Shale have been estimated at 97 Tcf over a prospective area of 51,252 km^2 (Table A.3; Table C.7; AWT International, 2013; AERA, 2018).

Data for the key unconventional hydrocarbon targets are summarised in Table C.8. The approximate extent of the tight/shale gas play in the Bowen Basin is shown in Figure C.12.

Although the Bowen Basin is still in an early phase of exploration, initial industry activity for shale and tight gas has been encouraging and the prospectivity of the basin is evident. However, due to the limited amount of drilling, the full extent of the shale and tight gas resources in the basin is not yet well understood and quantified. As a result, any estimates of potential resources have a high degree of uncertainty. Further seismic data acquisition, drilling and testing are required to improve our understanding of the shale and tight gas resource potential of this basin.

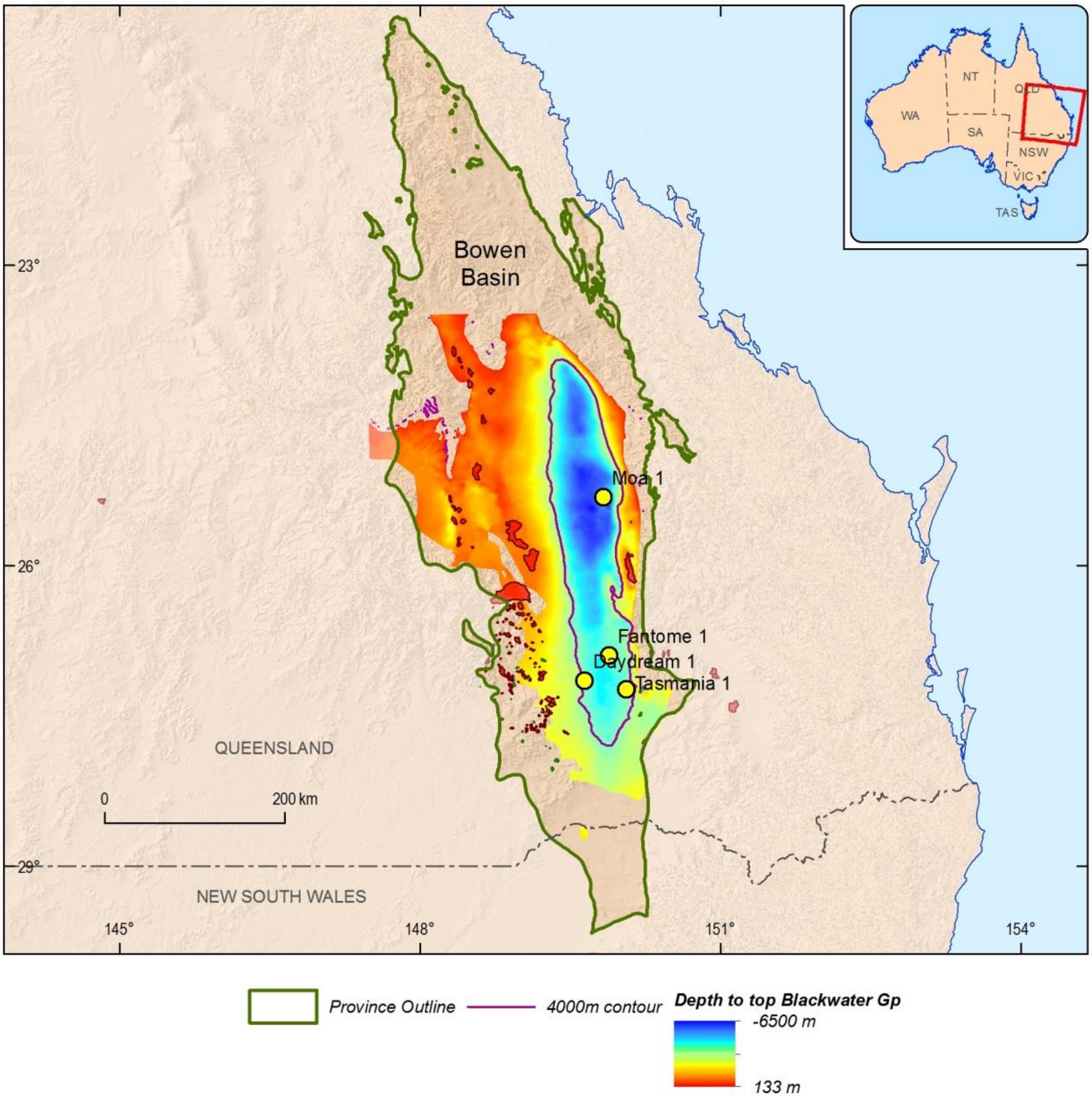

Figure C.12 Wells targeting shale/tight gas plays shown on the depth grid for the base of the Rewan Group/top Bandanna Formation. Approximate tight/shale gas play is indicated by the 4,000 m contour.

Table C.8 Summary of shale and tight gas plays compiled from literature and well completion reports.

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity (Ro)	Play type	Exploration status
Showgrounds Sandstone	Middle Triassic	fluvial-lacustrine	2,000-3,000	<50	Bandanna Fm and equiv. coals and carbonaceous shales (Type II/III)	N/A	main oil to wet gas; 0.95-1.15%	Tight gas	preliminary exploration
Rewan Formation (lower)	Early Triassic	fluvial-deltaic	2,500-3,500	<400	Bandanna Fm and equiv. coals and carbonaceous shales (Type II/III)		main oil to wet gas; 0.95-1.15%	Tight gas	preliminary exploration
Bandanna Formation	late Permian	deltaic	2,500-4,200	<180	Type II/III to Type III; coal, DOM	coal	main oil to wet gas; 0.95-1.15%	Shale/tight gas	preliminary exploration
Black Alley Shale	late Permian	marine-lacustrine	2,800-4,500	<60	Type II/III OM; marine shale	0.29-10.18%	main oil to wet gas; 0.85-~1.6%	Shale gas	preliminary exploration
Tinowon Formation	late Permian	shallow marine-deltaic	3,000-5,200	50-100	Wallabella Coal Mb; Bandanna Fm and equiv. coals and carbonaceous shales; early-late Permian marine shales		Main oil to dry gas; 0.95-1.15% 1.05-~2.0%;	Tight gas	preliminary exploration

C.2.4 Gas market access and infrastructure

The Bowen Basin is a major supplier of gas to Australia's East Coast Gas Market, with significant existing pipeline infrastructure connecting the basin to Brisbane (AER, 2017). The basin is moderately well serviced in terms of road and rail access.

Figure C.13 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.9.

Table C.9 Summary of market access and infrastructure. Pipeline information from AER (2017). Oil and gas infrastructure from GA (2015a).

INFRASTRUCTURE	
Gas market	Currently supplies to the east coast gas market
Gas pipelines	Existing gas pipelines within the basin, to Brisbane, Gladstone and from Cooper Basin: Wallumbilla–Brisbane; Wallumbilla–Gladstone; Fairview to Gladstone; APLNG Gladstone; Ballera–Roma
Gas processing facilities	Rolleston; Central; Wallumbilla; Kincora; Silver Springs
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	<100 km
Road and rail access	Moderately well serviced
Approximate development timeframe	5–10 years

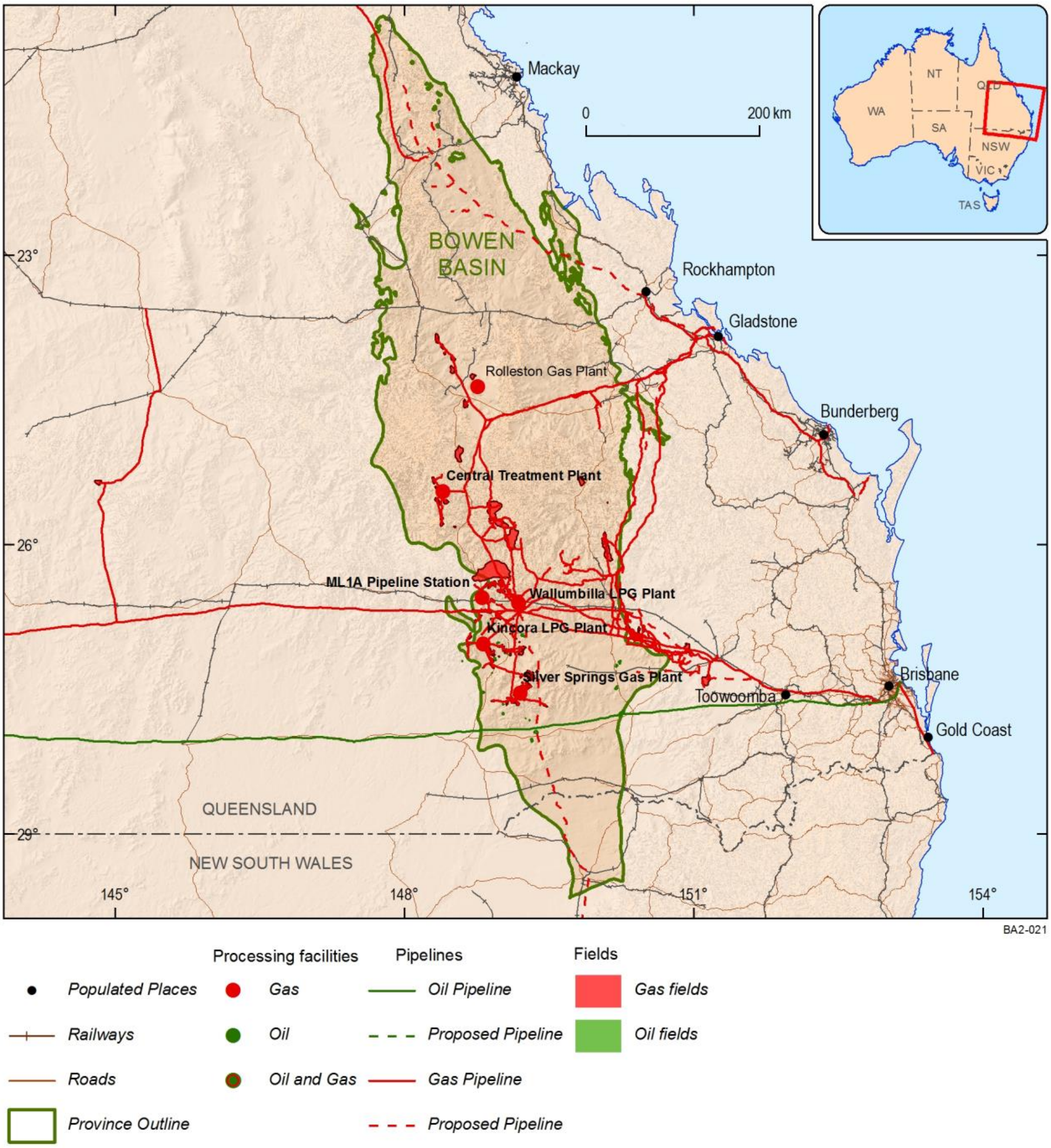

Figure C.13 Bowen Basin infrastructure, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

C.2.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia. There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.2.6 Hydrogeology and groundwater

C.2.6.1 Groundwater systems

Groundwater systems of the Bowen Basin region include aquifers in the northern Bowen Basin sequence, a range of aquifers in the Surat Basin (southern area), and alluvial and volcanic aquifers overlying the Surat Basin sediments. The northern half of the Bowen Basin is exposed, while the southern half, which connects with the Gunnedah Basin to the south, is overlain by the Surat Basin (Figure C.14).

Main aquifers in the north:

1. Alluvium (Quaternary), Basalts (Cenozoic) and Clematis Group sandstones (Triassic) where present
2. Rangal Coal Measures and equivalents (Permian)
3. Fort Cooper Coal Measures and equivalents (Permian)
4. Moranbah Coal Measures (Permian)

Main aquifers in the south:

1. Alluvial aquifers (Quaternary) associated with major rivers (i.e. the Condamine, Balonne, Dumaresq and Macintyre rivers) and antecedent systems that form palaeochannel infill and a broad and extensive alluvial cover (Paleogene–Quaternary).
2. Fractured rock aquifers of the Main Range Volcanics Formation (Oligocene–Miocene)
3. Sedimentary rocks of the Surat Basin (Jurassic–Cretaceous) that comprise aquifers of the Great Artesian Basin (GAB).
4. The Clematis Group sandstones (Triassic) and upper Permian coals (e.g. Baralaba Coal Measures, Bandanna, Muggleton and Burunga formations) are deeper aquifers that generally are not exploited where shallower options are available.

The Bowen Basin sequence is described in the Basin Geology section and shown in Figure C.10. Formations in the Permian succession beneath the coal measures (Back Creek Group) are generally considered aquitards (Figure C.15). The overlying Permian succession is treated as a combination of confined aquifers (generally coal beds) and aquitards (Arrow Energy, 2012). The main aquifers of this succession are in the Rangal Coal Measures and equivalents, Fort Cooper Coal Measures and equivalents, and the Moranbah Coal Measures. In these formations, groundwater flow is concentrated in the coals rather than the interburden (Arrow Energy, 2012) (Figure C.15). The overlying Rewan Group (Triassic) is generally considered to be an aquitard. In the south, the Bowen Basin is covered by the Surat basin which forms part of the great artesian basin (GAB), a sedimentary succession of varying hydraulic properties from aquitards to productive aquifers (Figure C.15).

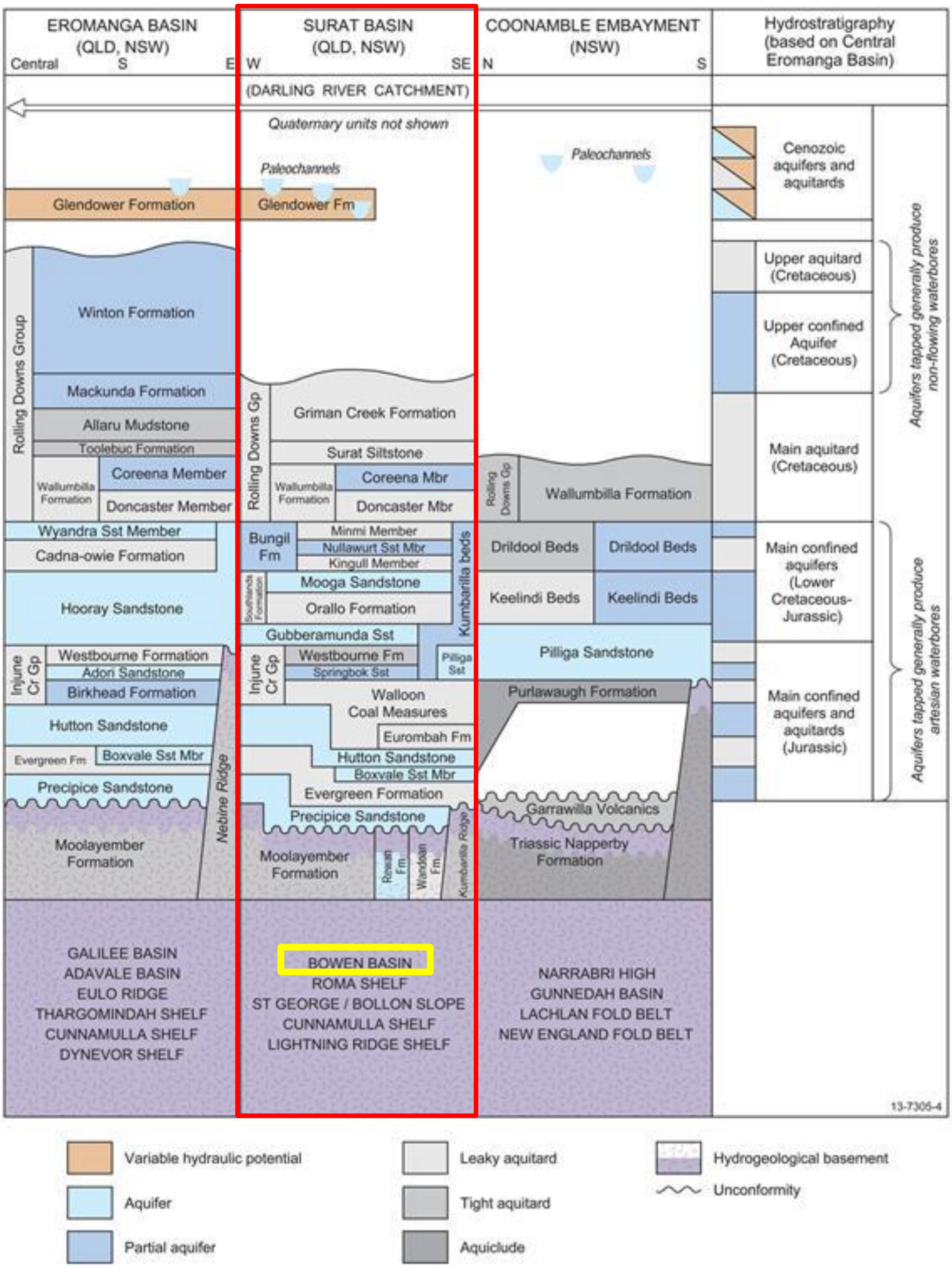

Figure C.14 Hydrostratigraphic relationships in the Surat Basin, Coonamble Embayment and adjoining Eromanga Basin of the Great Artesian Basin (extracted from Smerdon and Ransley, 2012). The yellow box identifies the Bowen Basin as underlying the Great Artesian Basin, with the red box showing this relationship to the overlying Surat Basin hydrostratigraphy.

Age	Stratigraphic Unit	Lithology	Typical Thickness (m)	Aquifer Type
Quaternary	Alluvium	Clay, silts, sand, gravel, floodplain alluvium	15-35	Unconfined (resource aquifer)
Tertiary	Suttor Formation	Clay, silt, sand, gravel, colluvium, fluvial and lacustrine deposits including cross-bedded quartz sandstone, conglomerate, claystone.	0-120	Aquitard
	Basalt	Olivine-rich weathered basalt remnants, moderately weathered and fresh basalts	0-80	Unconfined (resource aquifer); fractured rock aquifer
	Duaringa Formation	Mudstone, sandstone, conglomerate, siltstone, oil shale, lignite and basalt	0-50	Aquitard
Triassic	Moolayember Formation	Mudstone, lithic sandstone, interbedded siltstone, mudstone, sandstone and thin coal seams.	0-200	Confining unit - GAB
	Clematis Sandstone	Cross-bedded quartz sandstone, some quartz conglomerate, minor reddish brown mudstone.	0-300	Confined GAB aquifer
	Rewan Formation	Green lithic sandstone, pebble conglomerate, red and green mudstone, siltstone	200-800	Confining unit – base hydrogeological GAB
Late Permian	Rangal Coal Measures (RCM) and equivalents	Coal seams, carbonaceous shale and mudstone, tuff, siltstone and mudstone	25-200	Confined aquifer (coal) and confining unit (interburden)
	Fort Cooper Coal Measures and equivalents	Coal, brown and green sandstone, conglomerate, carbonaceous shale, tuff	100-600	Confined aquifer (coal) and confining unit (interburden)
	Moranbah Coal Measures	Coal, sandstone, siltstone, mudstone, carbonaceous mudstone	100-700	Confined aquifer (coal) and confining unit (interburden)
Middle Permian	Back Creek Group	Sandstone, siltstone, carbonaceous shale, minor coal and sandy coquinite	400-1200	Confining unit

Figure C.15 Hydrostratigraphy of the Bowen Basin from a representative location in the northern area, where the Surat Basin does not occur (Arrow Energy, 2012)

C.2.6.1.1 Alluvial aquifers

There are many alluvial aquifers throughout the Bowen Basin. These shallow groundwater flows are generally topographically driven. The alluvium generally has a lateral flow direction, similar to that of the major surface drainage.

- Border Rivers Alluvium—Useable groundwater is restricted to sediments deposited in narrow valleys associated with the Dumaresq and Macintyre rivers and the Macintyre Brook.

The valley broadens downstream of Keetah Bridge where groundwater generally becomes too saline for use. Other aquifers have been identified in this area (CSIRO, 2008) and they had a variety of recharge processes at play to varying degrees across the region.

- St George Alluvium—Kellett et al. (2006) provide a detailed description of the St George Alluvium and report that groundwater flow directions in the shallow alluvial aquifer are mainly north to the south-west, and radially outward along the axis of the Balonne River north of Whyenbah. Groundwater flow in the deeper alluvial aquifer is from north-east to south-west, parallel to the axis of the Dirranbandi palaeochannel. During the period 1998 to 2004, water levels in the upper alluvial aquifer remained stationary over most of the subregion, with the exception of irrigation areas in the vicinity of St George (Kellett et al., 2006). Groundwater recharge to the shallow alluvium occurs via multiple mechanisms, flooding recharge, natural river bed leakage and artificial recharge via infiltration of excess irrigation water in the St George Irrigation Area and groundwater irrigation area (Kellett et al., 2006). Groundwater recharge to deep alluvial aquifers is via bed underflow from the Balonne River upstream of Beardmore Dam where the aquifer is unconfined, and leakage from the shallow alluvial aquifer in the groundwater irrigation area (Kellett et al., 2006).

Cenozoic basalt aquifers

Cenozoic basalt aquifers, like much of the alluvium, form shallow unconfined aquifers over the Bowen Basin. Many shallow bores are sited on these basalts in the northwestern part of the basin. The Main Range Volcanics Formation is a significant Cenozoic basalt aquifer that is typically treated as a fractured-rock aquifer.

Surat Basin

The Surat Basin forms part of the Great Artesian Basin, which has been a subject of many studies, e.g. Smerdon and Ransley (2012). The cyclic grain-size variation in the basin formations produces a series of aquifers and aquitards, and there is substantial use of groundwater to meet the requirements of agricultural, industrial, energy, mining, domestic and commercial activities.

Bowen Basin Triassic units

Where present, the Clematis Group sandstones and equivalent formations are the main aquifers used in the Bowen Basin. The Moolayember Formation is primarily a fine-grained siltstone to mudstone and a confining bed for the Clematis Group sandstones, generally separating it from Surat Basin sediments above. Although minor aquifers occur within the Moolayember Formation, these are generally poor in quality and yield, and are not laterally continuous. Across most of the Bowen Basin, the Clematis Group sandstone aquifers are separated from the Bandanna Formation by a thick sequence of fine-grained, low-permeability siltstones and mudstones of the Rewan Group.

Recent studies have recognised the potential fluxes between many underlying geological basins and potential interaction between the Clematis Group and other aquifers of the Bowen Basin and the GAB.

Bowen Basin Permian units

Limited data is available on the groundwater conditions within the Permian sediments underlying the Bandanna Formation. However, in general, these formations are fine grained, cemented, and have little permeability. These formations are not as laterally extensive as those in the GAB, have complex geology and display laterally variable lithologies (DNRM, 2016). The Rangal, Fort Cooper and Moranbah coal measures, which are treated as deep aquifers, have both a primary porosity provided by the rock matrix and a secondary porosity of joints and fractures that provide the dominant groundwater flow pathways. The confining units have very low hydraulic conductivity, and thus limit both vertical flow and recharge; several mines in the northern Bowen Basin have described these units as ‘essentially impervious’ (Arrow Energy, 2012).

C.2.6.2 Groundwater quality

Throughout the Bowen Basin region, much of the groundwater is poor quality and only suitable for stock and domestic purposes. Habermehl (2002) states that groundwater quality of the overlying Surat Basin is variable; salinity is generally in the range of 500–1,500 mg/L in the Jurassic–Lower Cretaceous aquifers. Groundwater salinity reportedly increases away from the recharge areas in the east and north (<250 mg/L TDS in places) and along groundwater flow paths to the south and west to over 2,000 mg/L in places (Radke et al., 2000). Groundwater in the Jurassic–Lower Cretaceous aquifers is typically unsuitable for irrigation due to its high sodium adsorption ratio (Smerdon and Ransley, 2012).

C.2.6.3 Groundwater flow

Groundwater flow paths are generally towards the centre of the basin (Figure C.16). However, this is altered by substantial extraction, such as that related to coal mines and coal seam gas extraction. These activities can produce cones of depression in the potentiometric surfaces, and thus lead to flow paths towards the pits or gas production wells.

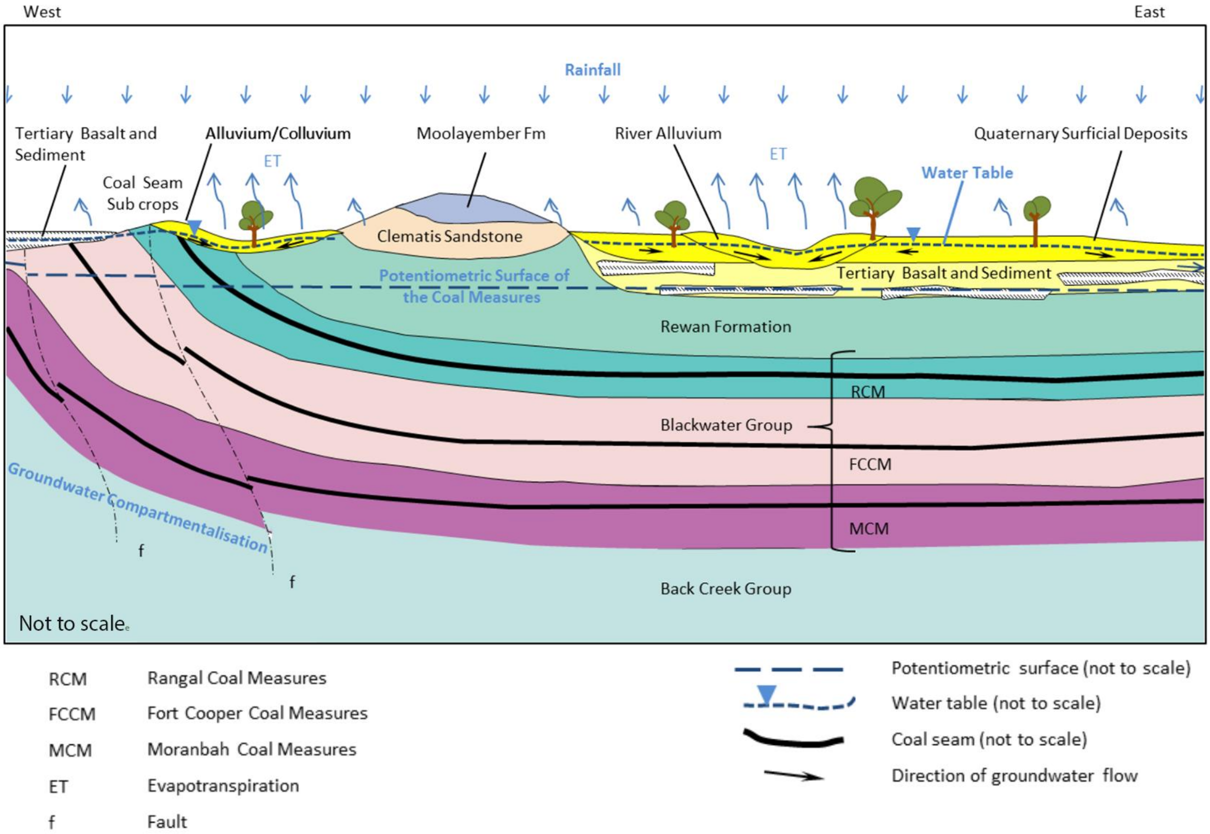

Figure C.16 Conceptual model for the northern Bowen Basin, as an east-west cross-section. The majority of groundwater flow is in the coal seams of the Blackwater Group (Arrow Energy 2012).

C.2.6.4 Groundwater planning and use

Groundwater planning and management is undertaken by the Queensland Government via Water Resource Plans. The Queensland water resource plans are subordinate legislation under the Water Act 2000 (Qld) (Queensland Government, 2000). They are prepared at a river basin scale, and specify the outcomes and strategies that will be used for each plan area.

Most groundwater extraction bores of the Bowen Basin are not metered, and accurately estimating the amount of groundwater used is very difficult. It is estimated that, other than relatively minor groundwater extractions from the Bandanna Coal Measures for stock and domestic purposes (Queensland Water Commission, 2012), there is currently no significant groundwater extraction from the coal measures or deeper geological formations by regional communities and rural landholders due to the poor water quality (high salinity) and low water yield (Coffey Environments, 2014).

Groundwater extracted for use in the Bowen Basin by the regional communities and rural landholders in current and future gas producing areas is sourced almost entirely from the shallow alluvial, basaltic and sedimentary aquifers that overlie the basin (URS, 2012). These aquifers are easier and less expensive to access yet have variable yields and moderate water quality (moderate salinity). The southern part of the Bowen Basin sits under the Great Artesian Basin and alluvium; it is part of the Surat Cumulative Management Area where the Office of Groundwater Impact Assessment (OGIA) produces an Underground Water Impact Report (DNRM, 2016).

The Clematis Group sandstone aquifers are managed under the Water Plan (Great Artesian Basin) 2006 (Queensland Government, 2006). These Triassic sandstones are an upper geological formation of the Bowen Basin, host water of low to high salinity, and are utilised in the southern part of the Basin (URS, 2012).

Recent studies have found that low connectivity is a dominant geological characteristic of aquifers across the Surat, Bowen and Galilee Basins (CSIRO, 2012a, b; Marsh et al., 2008; RPS, 2012; and Queensland Water Commission, 2012).

Table C.10 presents information from the Bureau of Meteorology's NGIS dataset and shows summary information of registered bores in the basin (BoM, 2016).

Table C.10 Summary of groundwater bores and water use in the Bowen Basin.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	14,769 (0.10)	
Purposes of registered bores (Top 5, number)	Unknown	10,132
	Stock	3,117
	Household	648
	Domestic Household	524
	Irrigated Agriculture	432
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 18 Median: 54 90th Percentile: 358.1	

C.2.7 Surface water systems and hydrology

C.2.7.1 Surface water systems

The river systems in the northern Bowen Basin are mostly tributaries to the Fitzroy River, including the Nogoa, Comet, Dawson and Brown river systems (Figure C.17). In the south, the Condamine-Balonne river system, part of the Murray-Darling Basin, is the dominant surface drainage system (Figure B.12; DNRM, 2016; BoM, 2014). Here, extensive floodplains associated with the upper and central areas of the Condamine River have associated alluvial aquifers running with the flow direction. The upper reaches flood every two years on average, resulting in widespread inundation (Welsh et al., 2014).

C.2.7.2 Surface water quality

In the northern section, there are some studies into the tributaries of the Fitzroy River, with various monitoring frequencies conducted at selected sites by a number of organisations. The Fitzroy is a moderate to highly salty system with slightly alkaline water. Headwater streams are quite fresh unless coal mine discharge affects the chemistry, with 80% of electrical conductivity (EC) values less than 280 µS/cm, but 3% of values are over 800 µS/cm. Coal mines have limits on the allowable discharge to the river system (DERM, 2009). During baseflow conditions, water quality in the river is good, but in the wet season higher suspended solids and nitrogen are encountered (Noble et al., 1996).

Whereas more is reported in the southern region, water quality measurements are carried out at only a few selected reaches of the Condamine-Balonne River. In the upper Condamine river basin, stream nutrients are generally within water quality guidelines, while the EC ranges from 100–800 µS/cm, which is greater than those found in other Queensland rivers.

C.2.7.3 Surface water flow

A series of river gauges record changes in river heights and are reported via the Bureau of Meteorology. The mean annual rainfall for the township of Emerald is 561.9 mm. Most of the rainfall occurs during the summer months of October to March and runoff is highest in summer and early autumn.

The Fitzroy River streamflow increases downstream with the greater catchment area, particularly as the steep slopes in the northeast of the catchment contribute; the headwater tributaries in the south (which overlie the Bowen Basin in the north) provide little to the river discharge (Figure C.18). Streamflow is also highly seasonal, with most of the flow occurring in December to April (Larsen et al., 2013). Gauge data availability in the catchment is variable, with some statistics available (Table C.11) and hydrographs (Figure C.19) in the compilation by SKM and Sunwater (2012).

In the south, the Condamine-Balonne river basin, including the Maranoa River, is a headwaters catchment to the Darling River (Figure C.20). The catchment contributes 13% by area of the Murray-Darling Basin, while providing 8.5% of the total runoff, and using 3% of the irrigation water (MDBA, 2015a). There are 42 stream gauge stations operated by the Queensland Department of Natural Resources and Mines, with record lengths from a few years to over 90 years. For example, the Balonne River at St George has a mean monthly flow of 10.5 GL. Most rainfall and runoff occurs in summer and autumn, and major flood events occur on average every two years (Figure C.21; Welsh et al., 2014; CSIRO 2008; MDBA, 2015a).

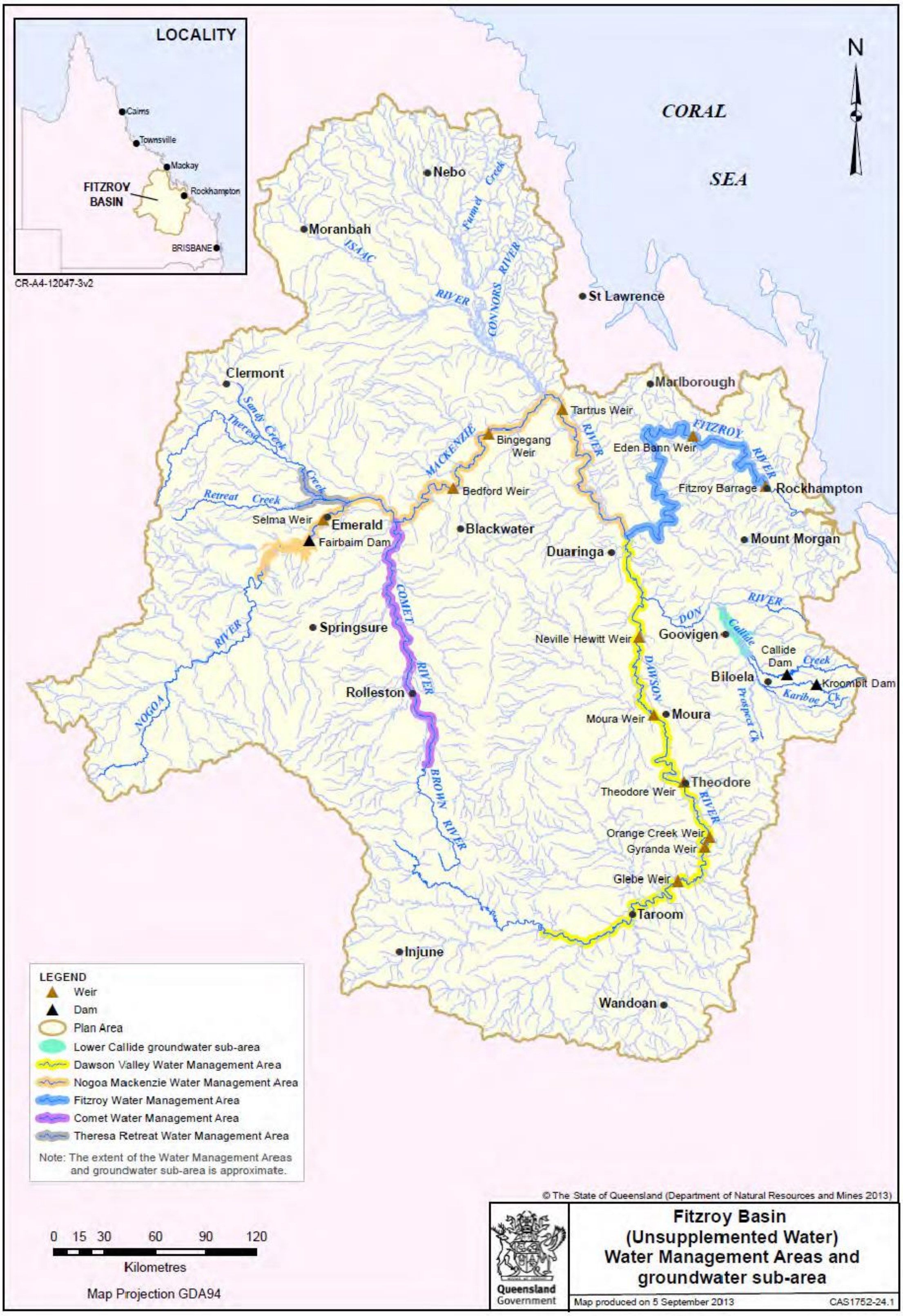

Figure C.17 Fitzroy River catchment, showing the Comet, Brown, Nogoa, and Dawson Rivers tributing from the south, and the various weirs and water supply schemes of this catchment (DNRM, 2015)

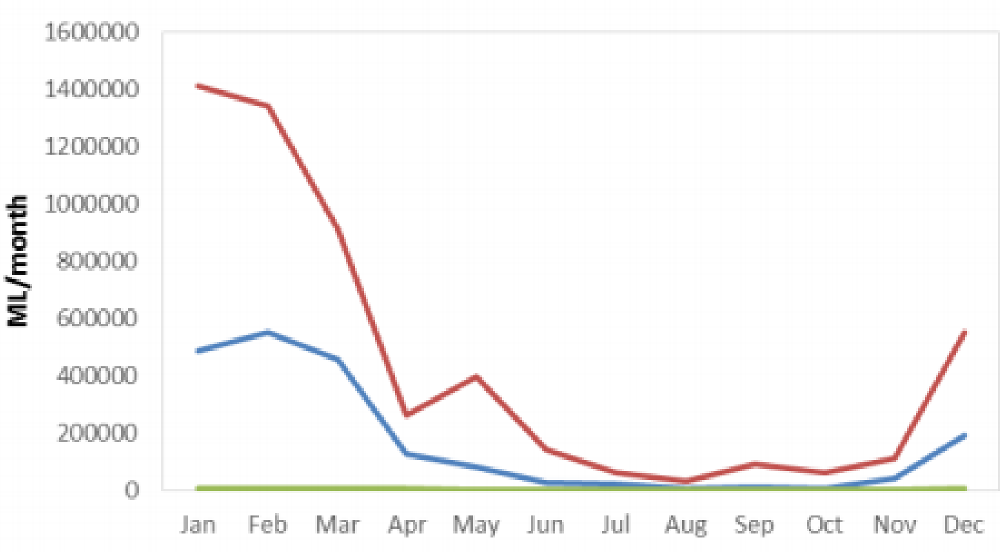

Figure C.18 The distribution of streamflow variation between months for selected components of the Fitzroy River catchment. Red = downstream discharge; Green = southern headwaters; Blue = north-eastern headwaters. From Larsen et al. (2013)

Table C.11 Streamflow statistics for various river gauges in the Fitzroy catchment (SKM and Sunwater, 2012).

Table 14-3 Fitzroy catchment gauge flow statistics

River	Location	Gauge no.	AMTD (km)	Period of Record	Mean Annual Flow (ML/a)	Minimum Annual Flow (ML/a)	Maximum Annual Flow (ML/a)	Median Annual Flow (ML/a)
Dawson River	Taroom	130302	384.6	1911-2006	358,920	2,940	2,880,780	204,580
	Glebe	130303	330.1	1919-2002	514,540	0	4,528,170	261,460
	Nathan Gorge	130320	307.2	1954-1986	736,850	3,220	4,574,020	217,000
	Theodore	130305	230.1	1924-2002	621,270	0	4,727,750	310,940
	Beckers	130322	71.0	1964-2006	755,110	500	4,618,250	325,820
	Boolburra	130301	16.1	1910-1978	1,160,260	2,980	5,533,930	838,430
Isaac River	Yatton	130401	43.0	1962-2007	1,980,850	9,970	16,633,300	568,610
Nogoa River	Fairbairn Dam	130216	685.6	1973-2002	212,940	0	1,352,070	0
Mackenzie River	Coolmaringa	130105	376.0	1971-2007	3,526,740	200,460	19,741,360	1,811,580
Fitzroy River	Riverslea	130003	276.0	1922-2007	4,724,360	96,120	23,874,300	2,710,450
	The Gap	130005	142.1	1964-2007	4,316,750	88,170	22,918,060	2,708,440
	Yaamba	130001	108.8	1914-1974	5,185,150	0	36,563,450	2,593,860

Source: DERM (2010) – note that data from years with a significant number of missing days has not been included in this analysis

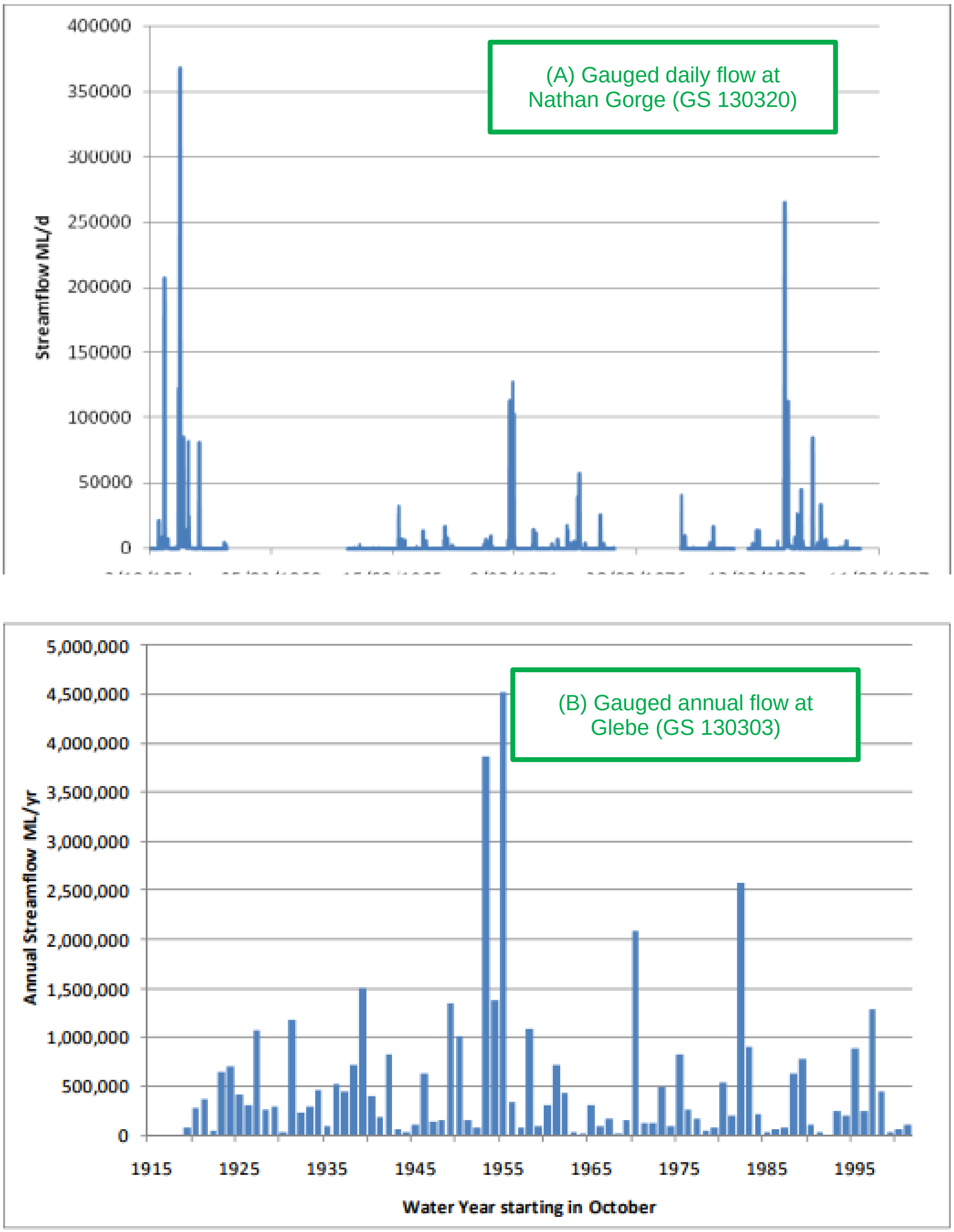

Figure C.19 Examples of stream hydrographs from the Dawson River catchment in the Fitzroy River region overlying the northern Bowen Basin. (A) daily streamflow for Nathan Gorge; (B) annual streamflow at Glebe. Extracted from SKM and Sunwater (2012)

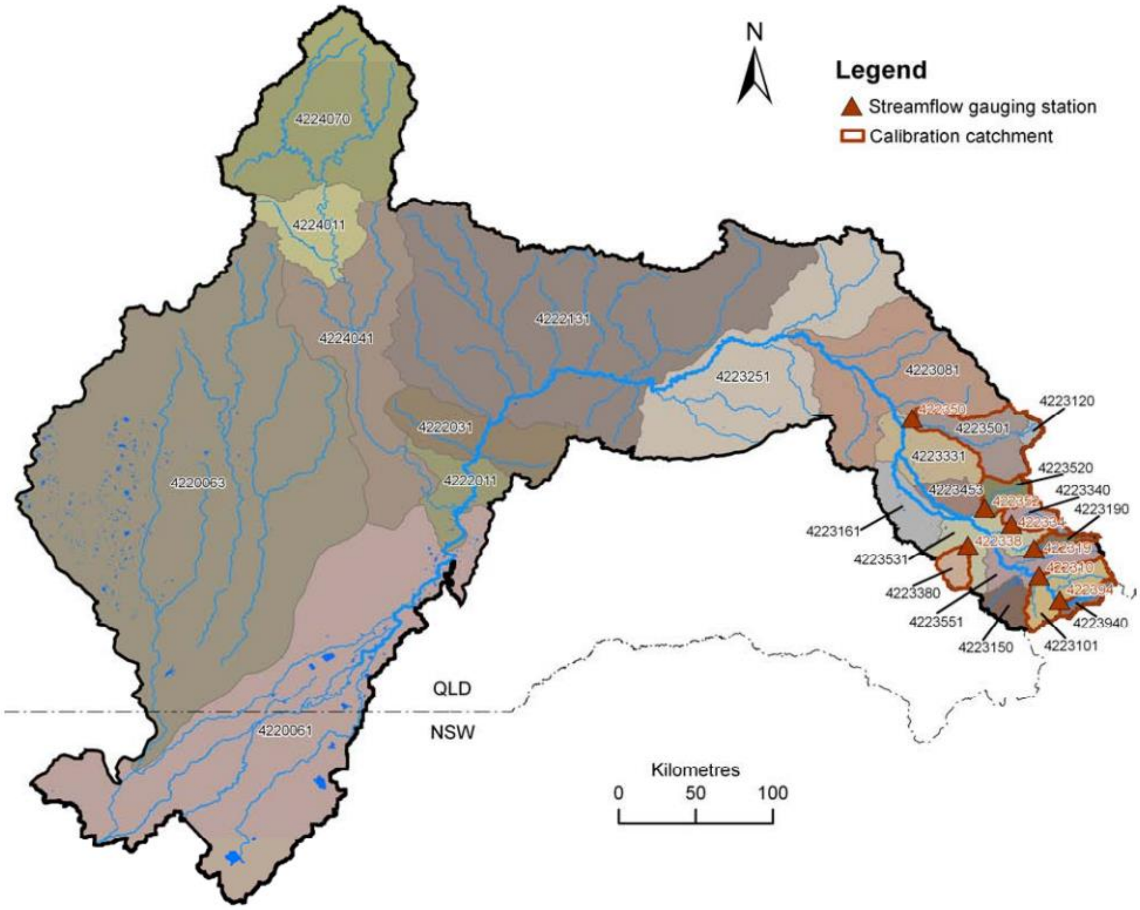

Figure C.20 Map of the Condamine–Balonne catchment, showing the various components of the stream network and streamflow gauging stations. Flow is from mostly east to west in the Condamine River, before becoming generally north to south in the Darling River downstream of this catchment. Figure adapted from CSIRO (2008).

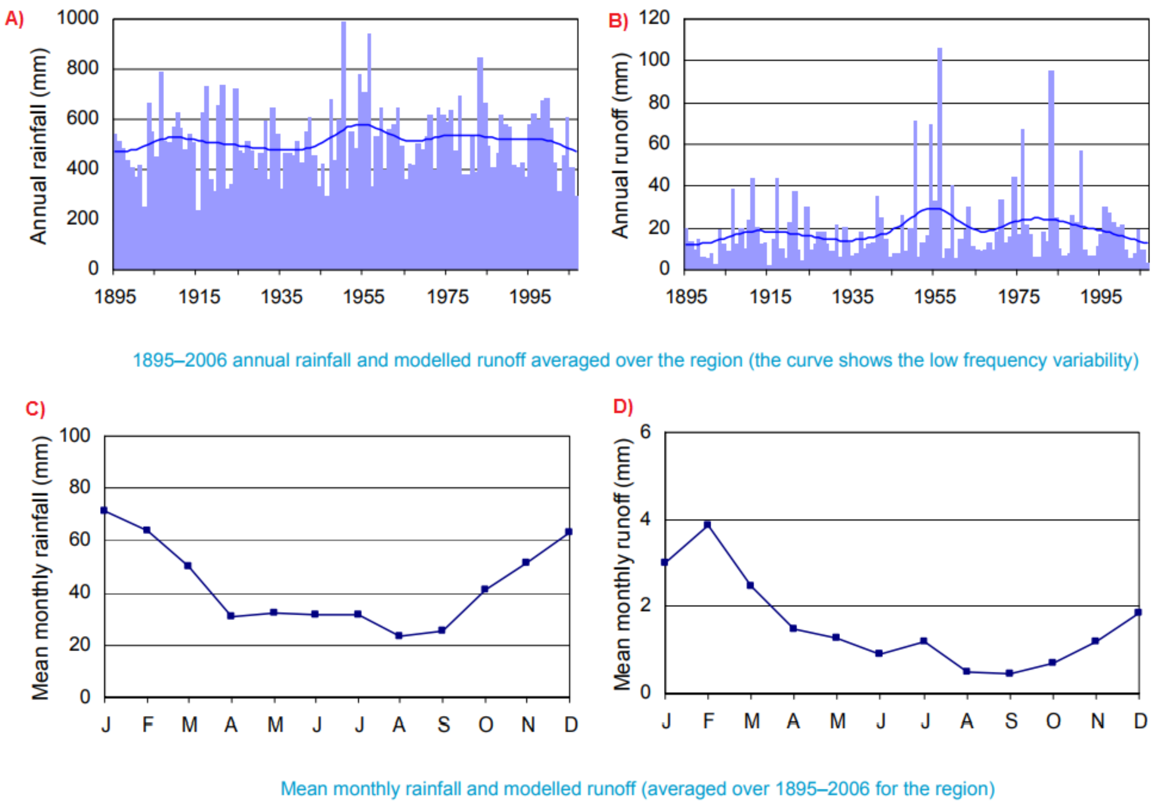

Figure C.21 Time-series data for the Condamine River catchment. (A) annual rainfall variation; (B) annual runoff variation; (C) variation between months for rainfall; (D) variation between months for runoff. Runoff (mm) multiplied by catchment area provides streamflow, so these graphs are indicative of the catchment as a whole. Figure adapted from CSIRO (2008).

C.2.7.4 Surface water dams, planning and use

There are multiple surface water storages across the northern part of the basin. These include the Fairbairn, Burton George, Teviot Creek dams, Lake Elphinstone, Lake Vermont, Lake Nuga Nuga, Lake Bundoora and off stream storages, for example at Gatonvale. Some of these are extended by pipeline channel systems.

The southern part of the Bowen Basin coincides with the Maranoa-Balonne-Condamine subregion used in the Bioregional Assessments into coal and coal-seam-gas, as reported in Welsh et al. (2014). It includes the Moonie, Condamine-Balonne, and Border Rivers river basins; it forms part of the Murray Darling Basin (Thoms and Parsons, 2003) and is covered by the Basin Plan 2012 (DNRM, 2014; MDBA, 2015b; Federal Register of Legislation 2012). Some of these river basins contain several nationally significant wetlands (DEWHA 2010).

C.2.8 Groundwater–surface water interactions

Little is known about the interactions of groundwater and surface water in the Fitzroy River catchment of the northern Bowen Basin. Most of the smaller watercourses in the Fitzroy catchment flow intermittently or are ephemeral, relying on wet season events for streamflow; however, larger rivers may contain permanent water (SKM and Sunwater, 2012; Noble et al., 1996). Extensive instream perennial pools occur along the length of the Dawson River (SKM and Sunwater, 2012).

Aspects of groundwater–surface water interactions for specific areas of Condamine catchment have been investigated, with a few generalised studies. The upper Condamine River reaches are classified as medium water losing, but downstream of Chinchilla Weir gaining conditions from groundwater are found; further downstream these become losing reaches of the Darling River (Figure C.22) (Welsh et al., 2014). Radon and chloride measurements suggest that the northern tributaries to the Condamine have about 20–70% contribution from groundwater sources, due to their wide alluvial floodplains, shallow topographic gradients and shallow water tables (Martinez et al., 2015).

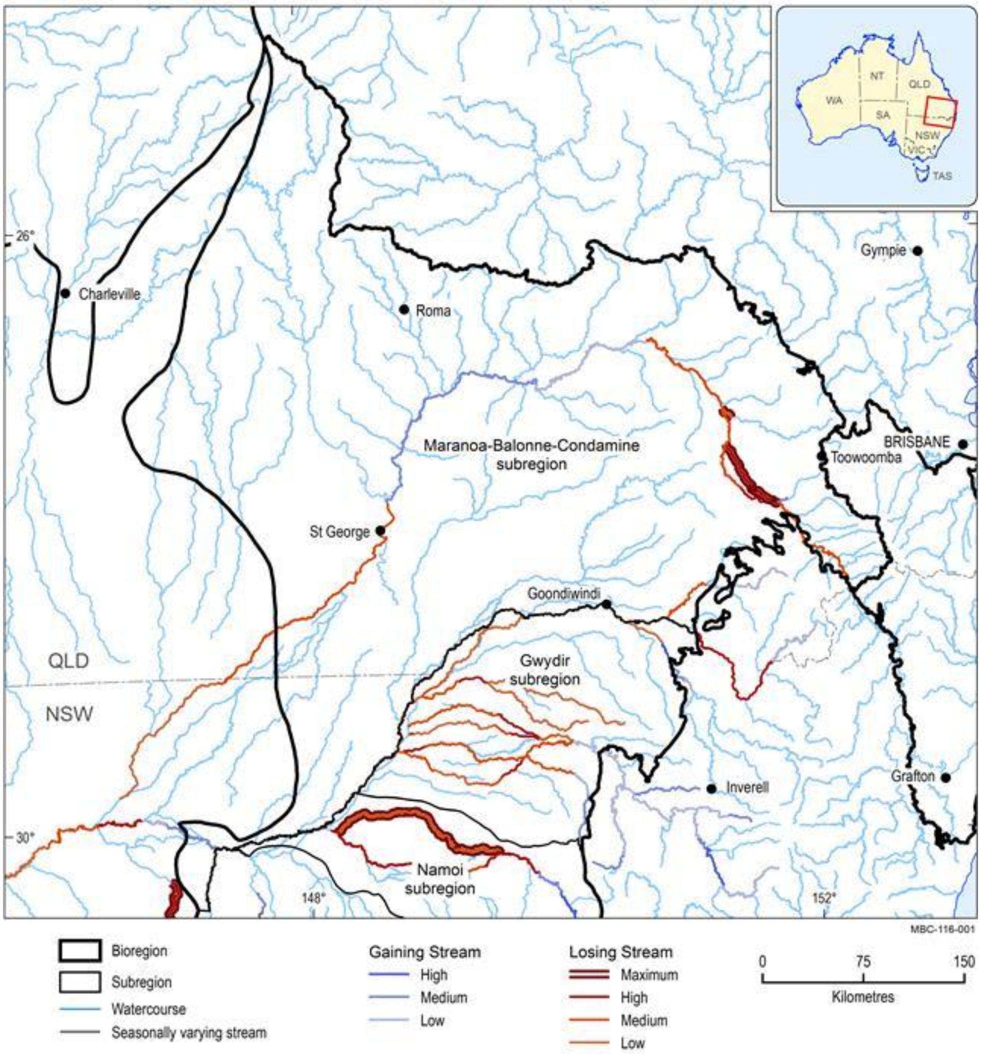

Figure C.22 Surface water – groundwater connectivity in the Maranoa-Balonne-Condamine subregion, overlying the southern Bowen Basin (Welsh et al., 2014).

C.2.9 Environmental Assets

Within the Bowen Basin there are 731 km^2 of Listed Nationally Important Wetlands, 26,000 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential), 5,917 km^2 of protected areas (such as national parks); there are no Ramsar wetlands (Table C.12).

Table C.12 Summary of environmental assets in the Bowen Basin

Environmental Assets		
Ramsar Wetlands	None	
Nationally Important Wetlands Top 5 by area (area km^2)	Palm Tree and Robinson Creeks	490
	Fairbairn Dam	151
	Broad Sound	58
	Lake Nuga Nuga	20
	Boggomoss Springs	4
	TOTAL WETLAND AREA	731
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	National Park	4,728
	NRS Addition - Gazettal in Progress	698
	Nature Refuge	427
	Regional Park	47
	Nature Reserve	13
	TOTAL PROTECTED AREA	5,917
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	26,000	

C.2.10 Social Considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in Table C.13.

Table C.13 Summary of social considerations, Bowen Basin

GENERAL CHARACTERISTICS		
Population	80,873	
Major population centres (two)	Emerald, Roma	
Land use types Top 5 by area (area km^2)	Grazing native vegetation	116,334
	Dryland cropping	16,314
	Production forestry	8,503
	Nature Conservation	5,251
	Irrigated cropping	2,114
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	11,083	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

Al Arouri, A, Boreham, CJ, McKirdy, DM and Lemon, NM (1998) Modeling of thermal maturation and hydrocarbon generation in two petroleum systems of the Taroom Trough, Australia. AAPG Bulletin, 82(8), 1504–1527.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

Arrow Energy (2012) Bowen Gas Project Environmental Impact Statement. Section 14: Groundwater. Viewed 22/01/2018, <https://www.arrowenergy.com.au/__data/assets/pdf_file/0003/3837/Section_14-Groundwater.pdf>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

Boreham CJ (1995) Origin of petroleum in the Bowen and Surat basins: geochemistry revisited. Australian Petroleum Exploration Association Journal, 35(1), 579–612.

CAPAD (2016) Collaborative Australian Protected Area Database, 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

CSIRO (2012a) Water resource assessment for the Central Eromanga region. Canberra: Commonwealth of Australia.

CSIRO (2012b) Water resource assessment for the Surat region. Canberra: Commonwealth of Australia.

CSIRO (2008) Water availability in the Condamine-Balonne. A report to the Australian Government from the CSIRO Murray-Darling Basin Sustainable Yields Project. CSIRO, Australia. 169pp.

Coffey Environments Australia Pty Ltd (2014) Supplementary Groundwater Assessment. Brisbane: Arrow Energy.

DERM (2009) A study of the cumulative impacts on water quality of mining activities in the Fitzroy River Basin. Viewed 22/01/2018, <http://riverhealth.org.au/wp-content/uploads/2017/05/A-study-of-the-cumulative-impacts-on-water-quality-of-mining-activites-i....pdf>.

DEWHA (Department of the Environment, Water, Heritage and the Arts) (2010) A Directory of Important Wetlands in Australia (DIWA) Spatial Database, third edition. Viewed 10/08/2017, <http://www.environment.gov.au/fed/catalog/search/resource/details.page?uuid=%7BE6C815D9-FB67-4372-AC25-81C7473CCD21%7D>.

DNRM (Department of Natural Resources and Mines) (2014) "Water Resource Planning" Queensland Murray-Darling Basin. Web page, Department of Natural Resources and Mines, Queensland Government. Viewed 29/09/2017, <https://www.dnrm.qld.gov.au/water/catchments-planning/qmdb/water-resource-planning>.

DNRM (Department of Natural Resources and Mines) (2015) Fitzroy Basin: Resource operations Plan, September 2014, Amended September 2015. Viewed 29/09/2017, <https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0003/298650/fitzroy-rop-amendment-2015.pdf>.

DNRM (Department of Natural Resources and Mines) (2016) Underground Water Impact Report for the Surat Cumulative Management Area 2016. Viewed 29/09/2017, <https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0007/345616/uwir-surat-basin-2016.pdf>.

DNRM (Department of Natural Resources and Mines) (2017a) Queensland’s petroleum and coal seam gas. Department of Natural Resources and Mines. Viewed 23/07/2017, <https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0008/1237742/qld-petroleum-coal-seam-gas-2017.pdf>

DNRM (Department of Natural Resources and Mines) (2017b) Queensland’s unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DNRM (Department of Natural Resources and Mines) (2017c) Burdekin Basin Water Management Protocol May 2017. Viewed 16/01/2018, <https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0020/1253090/burdekin-basin-water-management-protocol.pdf>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

Draper JJ (2013) Bowen Basin. In: Jell PA (ed.), Geology of Queensland. Geological Survey of Queensland, 371–384.

Federal Register of Legislation (2012) "Basin Plan 2012", instrument under the Water Act 2007 (Cwlth), affecting the Murray-Darling Basin, compiled 23 January 2017. Viewed 29/09/2017, <https://www.legislation.gov.au/Details/F2017C00078>.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Green PM (ed.) (1997) The Surat and Bowen Basins, south-east Queensland. Queensland Minerals and Energy Review Series, Queensland Department of Mines and Energy.

Habermehl MA (2002) Hydrogeology, hydrochemistry and isotope hydrology of the Great Artesian Basin. GAB Fest.

Hayes BJ, Nicholls P, Dorey K, Bresnahan R, McDougall W and Wickens C (2016) Comparing basin-centred gas prospectivity in the Bowen-Surat Basin (Queensland, Australia) with the Deep Basin of western Canada and the Piceance Basin of Utah. AAPG 2016 Annual Convention and Exhibition, Abstract. AAPG Search and Discovery Article #10866. Viewed 18/01/2018, <http://www.searchanddiscovery.com/pdfz/documents/2016/10866hayes/ndx_hayes.pdf.html>.

Kellett JR, Pearce B, Coram J, Herczeg A, Wilkinson K and Cresswell R (2006) National Action Plan for Salinity and Water Quality. Salinity investigations using airborne geophysics in the Lower Balonne area, Southern Queensland. Chamberlain T and Wilkinson K. Queensland, Department of Natural resources and Mines.

Korsch RJ and Totterdell JM (eds) (2009) Evolution of the Bowen, Gunnedah and Surat basins, eastern Australia (Thematic Issue). Australian Journal of Earth Sciences, 56(3).

Larsen J, Leon J, McGrath C and Trancoso R (2013) Review of the catchment processes relevant to the Great Barrier Reef region. Great Barrier Reef Marine Park Authority, Townsville.

Marsh C, Kane R, Rick C, Aleks K and Ian N (2008) A Geological Review of the Galilee Basin, Queensland for Possible Storage of Carbon Dioxide. Canberra: CRC for Greenhouse Gas Technologies

Martinez JL, Raiber M and Cox ME (2015) Groundwater-surface water interaction in the Condamine River headwaters, Southeast Queensland, Australia: combining long-term hydrochemical records and isotope hydrology. Poster at the 42nd IAH Congress, Rome, Italy, September 2015.

MDBA (Murray-Darling Basin Authority) (2015a) Condamine–Balonne Catchment, Discover the Basin. Viewed 13/09/2017, <https://www.mdba.gov.au/discover-basin/catchments/condamine-balonne>.

MDBA (Murray-Darling Basin Authority) (2015b) "Basin Plan". Web page, Murray-Darling Basin Authority, Australian Government. Viewed 29/09/2017, <https://www.mdba.gov.au/basin-plan>.

Nicholls P, Bresnahan R, Hayes BJ, Dorey K and McDougall W (2015) Unconventional resource potential of the Taroom Trough in the southern Surat-Bowen Basin, Queensland, Australia. AAPG/SEG International Conference and Exhibition, Melbourne, Australia, Extended Abstract. AAPG Search and Discovery Article #10804. Viewed 22/01/2018, <http://www.searchanddiscovery.com/documents/2015/10804nicholls/ndx_nicholls.pdf>.

Noble RM, Duivenvoorden LJ, Rummenie SK, Long PE and Fabbro LD (1996) Downstream Effects of Land Use. Department of Natural Resources, Brisbane.

Queensland Government (2000) "Water Act 2000". Act of the Parliament of Queensland, Current as at 3 July 2017. Viewed 29/09/2018, <https://www.legislation.qld.gov.au/view/pdf/inforce/current/act-2000-034>.

Queensland Government (2006) “Water Plan (Great Artesian Basin) 2006”, legislation under the Water Act 2000 (Qld), current as at 3 July 2017, Viewed 04/08/2017, <https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf>.

Queensland Water Commission (2012) Annual Report 2011-12, Queensland Water Commission. ISSN 1837-4832 (Print).

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 29/09/2018, https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells.

Radke BM, Ferguson J, Cresswell RG, Ransley TR, Habermehl MA (2000) Hydrochemistry and implied hydrodynamics of the Cadnaowie – Hooray Aquifer, Great Artesian Basin. Bureau of Rural Sciences, Canberra ISBN 0 642 47554 7.

Raymond OL, Gallagher R and Highet LM (2012) Surface geology of Australia, 1:2 500 00 scale, 2012 edition. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!b4088aa1-f875-2444-e044-00144fdd4fa6>.

RPS (2012) Galilee Basin - Report on the Hydrogeological Investigations. Brisbane: Galilee Basin Operators Forum.

SKM and SunWater (2012) Nathan Dam Environmental Impact Statement, Chapter 14: Surface Water.

Smerdon B and Ransley T (2012) Water resource assessment for the Surat region (1st ed.). Canberra: Commonwealth of Australia.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Thoms MC and Parsons (2003) Identifying spatial and temporal patterns in the hydrological character of the Condamine-Balonne River, Australia, using multivariate statistics. River Res. Appl. 19, 443–457

URS (2012) Groundwater Impact Assessment Bowen Gas Project. Appendix L of Arrow Bowen Gas Project EIS. Brisbane: Arrow Energy. https://www.arrowenergy.com.au/__data/assets/pdf_file/0008/3869/Appendix-L_Groundwater-and-Geology-Technical-Report.pdf

Welsh W, Herron N, Rohead-O’Brien H, Ransley T, Aryal S, Mitchell P, Buckerfield S and Marshall S (2014) Context statement for the Maranoa-Balonne-Condamine subregion. Product 1.1 for the Maranoa-Balonne-Condamine from the Northern Inland Catchments Bioregional Assessment. Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

C.3 Clarence-Moreton Basin

Table C.14 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	New South Wales, Queensland
Area	38,431 km^2
Max. basin depth/ sediment thickness	< 4,000 m
Age range	Late Triassic–Early Cretaceous
Depositional setting	Fluvial, paludal and lacustrine siliciclastic rocks and coal; volcanic and intrusive igneous rocks
Regional structure	Elongate sag basin with an overall synclinal architecture
Adjacent basin	Surat Basin
EXPLORATION STATUS	
Seismic lines	2,909 line km 2D seismic
Number of wells	51
Exploration status – conventional	Inactive (following preliminary exploration)
Exploration status – coal seam gas	Preliminary exploration
Exploration status – shale/ tight gas	Inactive (following preliminary exploration)
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Abundant gas and minor oil shows
Prospectivity	Moderate-low
Conventional discoveries	Kingfisher E01
Hydrocarbon production – total to date	No production to date (AERA, 2018)
2P Reserves	1.13 Tcf CSG; no conventional reserves (current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	0.1 Tcf conventional; 5.3 Tcf CSG (current to 2014; AERA, 2018)
Undiscovered resource estimates	3,816 PJ (approx.. 3.5 Tcf) CSG (Core, 2014); see below for shale and tight gas
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Shale gas, tight gas
No. of wells targeting shale/ tight gas plays	1 (conventional and unconventional targets)
Production – shale/ tight gas	None

2P Reserves – shale/ tight gas	None reported
Remaining resources (reserves + contingent resources) – shale/ tight gas	None reported
Undiscovered resource estimates – shale/ tight gas	Koukandowie and Raceview Formation shale gas plays: 21 Tcf best estimated recoverable resource over a prospective area of 4,407 km^2 (Table A.3; AWT International, 2013; AERA 2018); tight gas unknown
Hydrocarbon shows, tests – shale/ tight gas	None reported

C.3.1 Basin geology

The Clarence-Moreton Basin is a Late Triassic–Cretaceous sag basin that has a general north-northeast structural trend. It extends from northern New South Wales into Queensland and adjoins the Surat Basin to the west (Figure C.23). The basin extends offshore, where its extent, thickness and geology are poorly known (Figure C.24; Totterdell et al., 2014).The onshore basin contains up to 4,000 m of Upper Triassic to Upper Jurassic or Lower Cretaceous dominantly fluvio-lacustrine sedimentary rocks (Figure C.25 and Figure C.26).

The Clarence-Moreton Basin comprises a series of generally north-northeast-trending depocentres: the Cecil Plains, Laidley and Logan sub-basins (Figure C.24; O'Brien et al., 1994a). The sub-basins are underlain by the Triassic sediments and volcanics of the Esk Trough and the Nymboida, Ipswich and Tarong basins. The sub-basins of the Clarence-Moreton Basin are separated by prominent structural highs, including the Gatton Arch and the South Moreton Anticline. The Clarence-Moreton Basin succession abruptly thins across the South Moreton Anticline.

The Clarence-Moreton Basin was initiated in the Late Triassic through continued thermal subsidence following the end of deposition in the Ipswich Basin (Korsch et al., 1989; O'Brien et al., 1994a). Uplift of basin margins supplied quartzose to quartz-lithic sediments to the basin and the accumulation of alluvial fan and fluvial deposits. By the Early Jurassic, the maximum extent of the basin was established. In the Middle Jurassic, widespread fluvio-lacustrine and paludal conditions led to the deposition of the Walloon Coal Measures, which attain a maximum thickness of approximately 600 m. The coal measures mainly comprise claystones, coal and lithic sandstones, but are sandstone dominated in parts of the basin (Stewart and Alder, 1995). The Walloon Coal Measures are overlain by a dominantly fluvial Upper Jurassic–Lower Cretaceous succession (Willis, 1994; Stephenson and Burch, 2004). Ongoing strike-slip movements along the major basement-involved faults, e.g. West Ipswich Fault, resulted in transpressional deformation of the Clarence-Moreton Basin sediments through the Jurassic until the Early to mid-Cretaceous (O'Brien et al., 1994a). Regional uplift resulted in widespread erosion across the onshore basin during the Cretaceous.

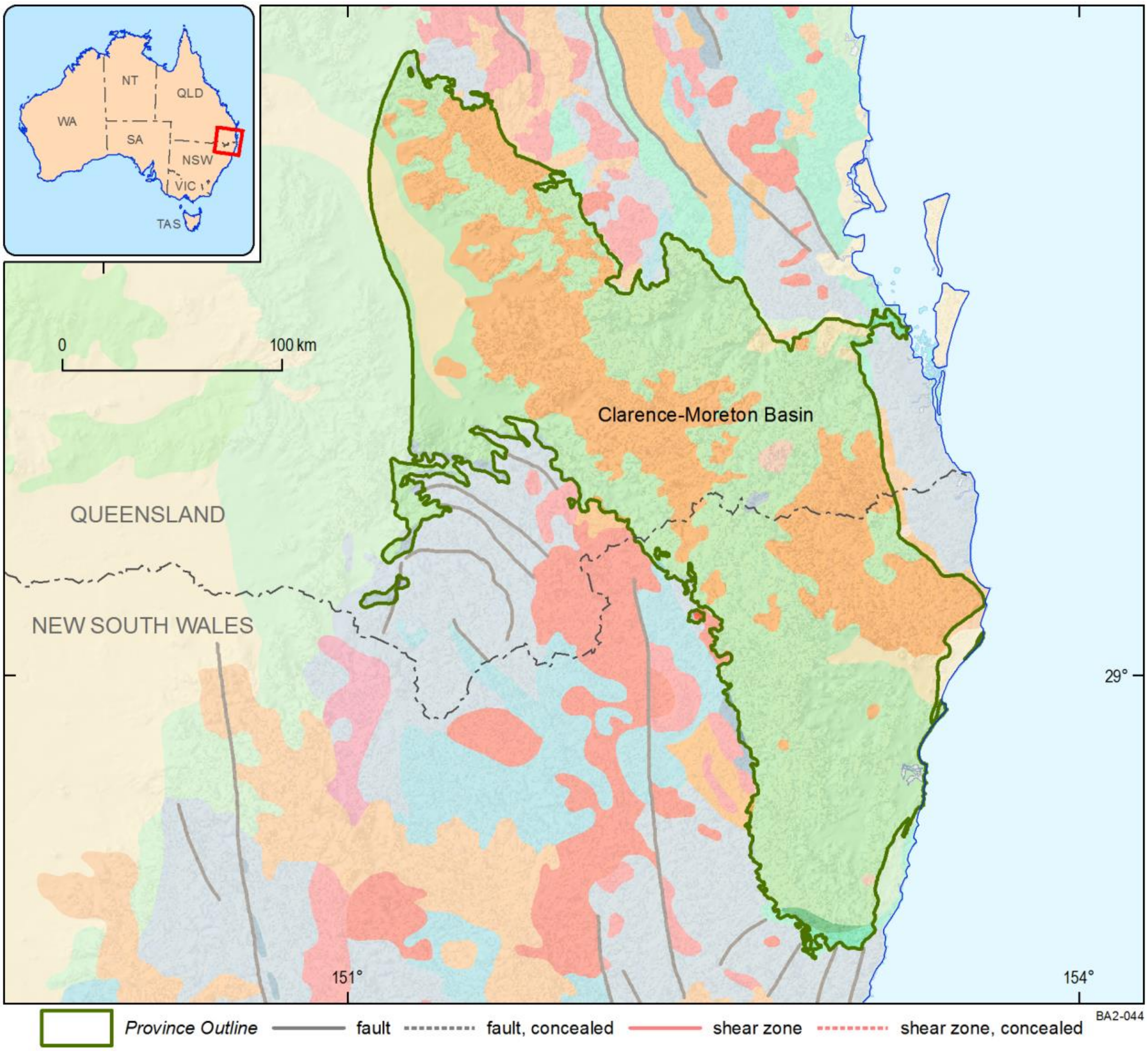

Figure C.23 Location of the Clarence-Moreton Basin on a base map of 1:2,500,000 scale surface geology (Raymond et al., 2012). Clarence-Moreton and Surat basin outlines from Stewart et al. (2013).

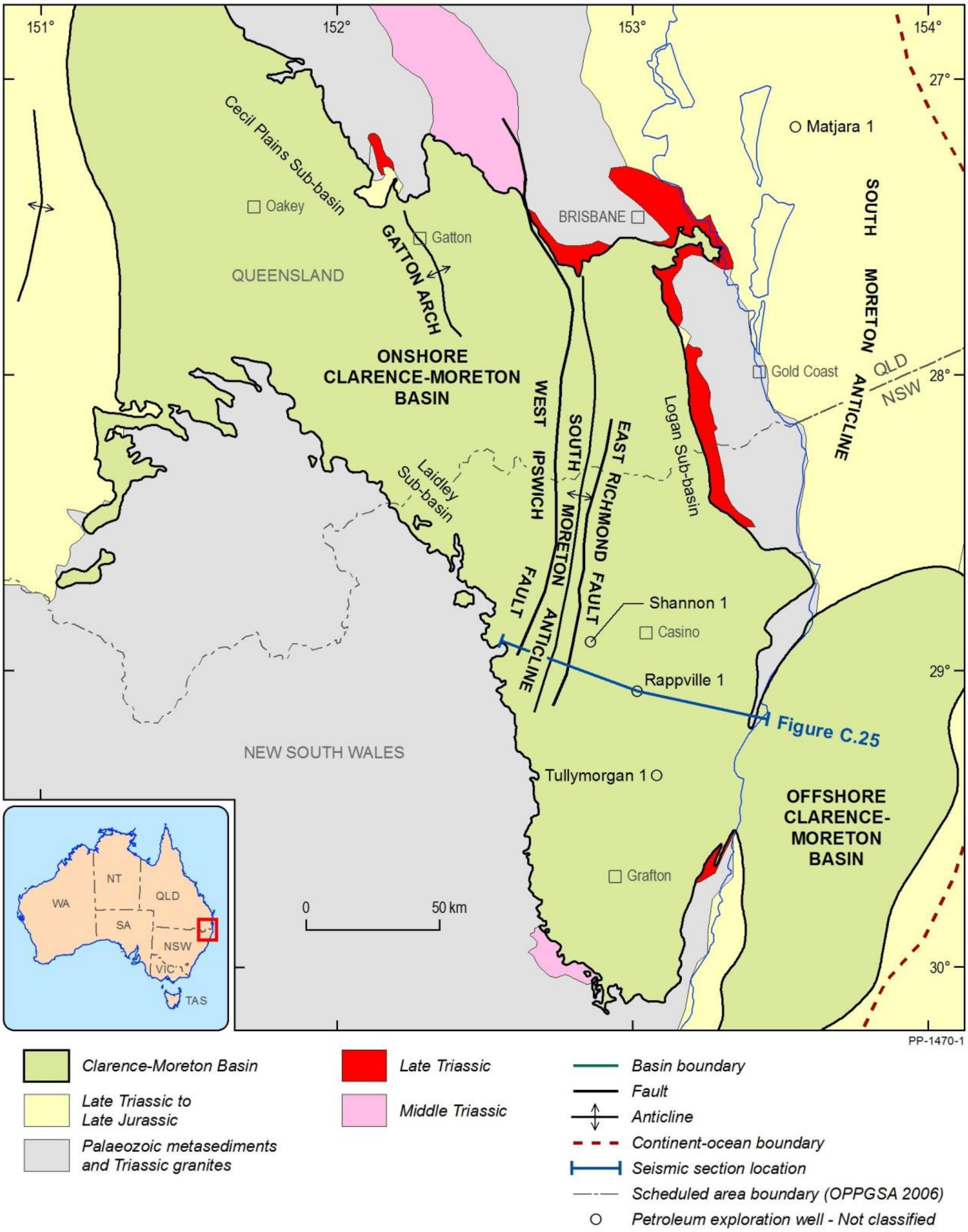

Figure C.24 Structural elements, onshore and offshore Clarence-Moreton Basin (from Totterdell et al., 2014).

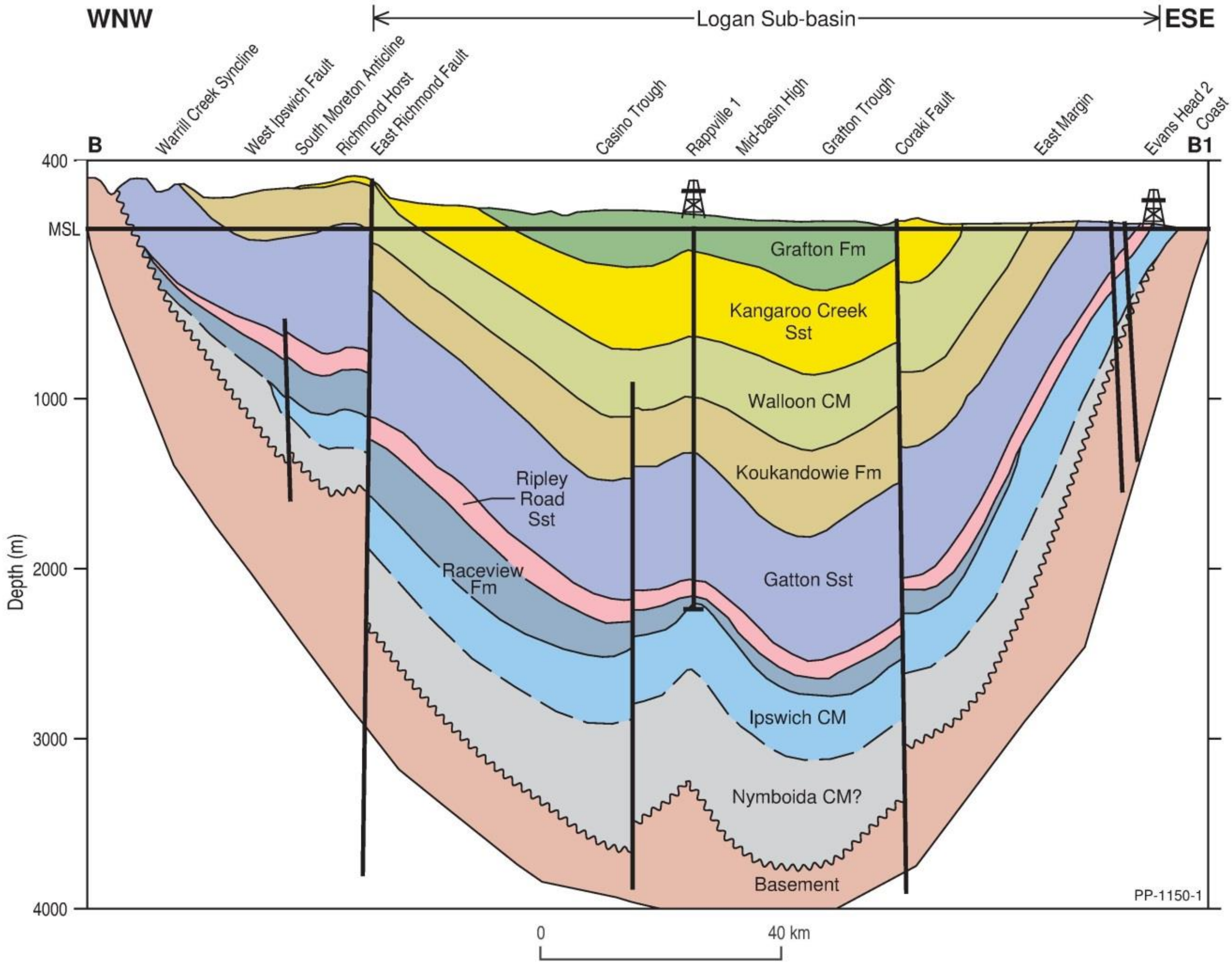

Figure C.25 Geological cross-section of the Nymboida, Ipswich and Clarence-Moreton basins (after Ingram and Robinson, 1996). Location of cross-section shown in Figure C.23.

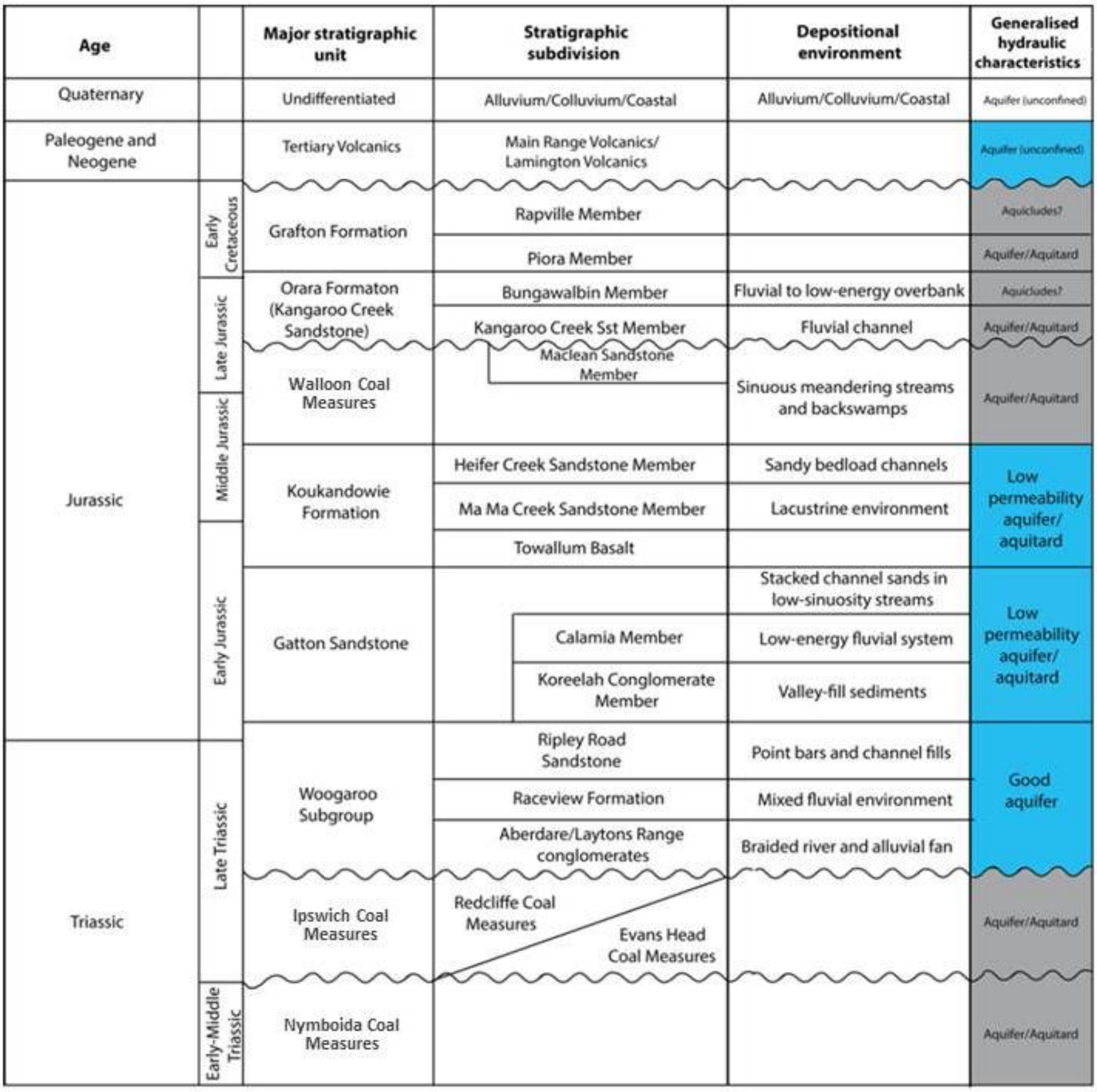

Figure C.26 Lithostratigraphy and hydrostratigraphy of the Clarence-Moreton Basin (after Rassam et al., 2014; Wells and O'Brien, 1994; Doig and Stanmore, 2012; Raiber and Cox, 2012)

C.3.2 Petroleum data coverage

The onshore Clarence-Moreton Basin is relatively poorly explored and has a sparse coverage of reflection seismic data of varying vintage and quality (Figure C.27; DNRME, 2017b-d; GSNWS, 2017). More than 50 petroleum wells have been drilled in the basin, 29 in Queensland and 22 in New South Wales (DNRME, 2017a; DREMP, 2017).

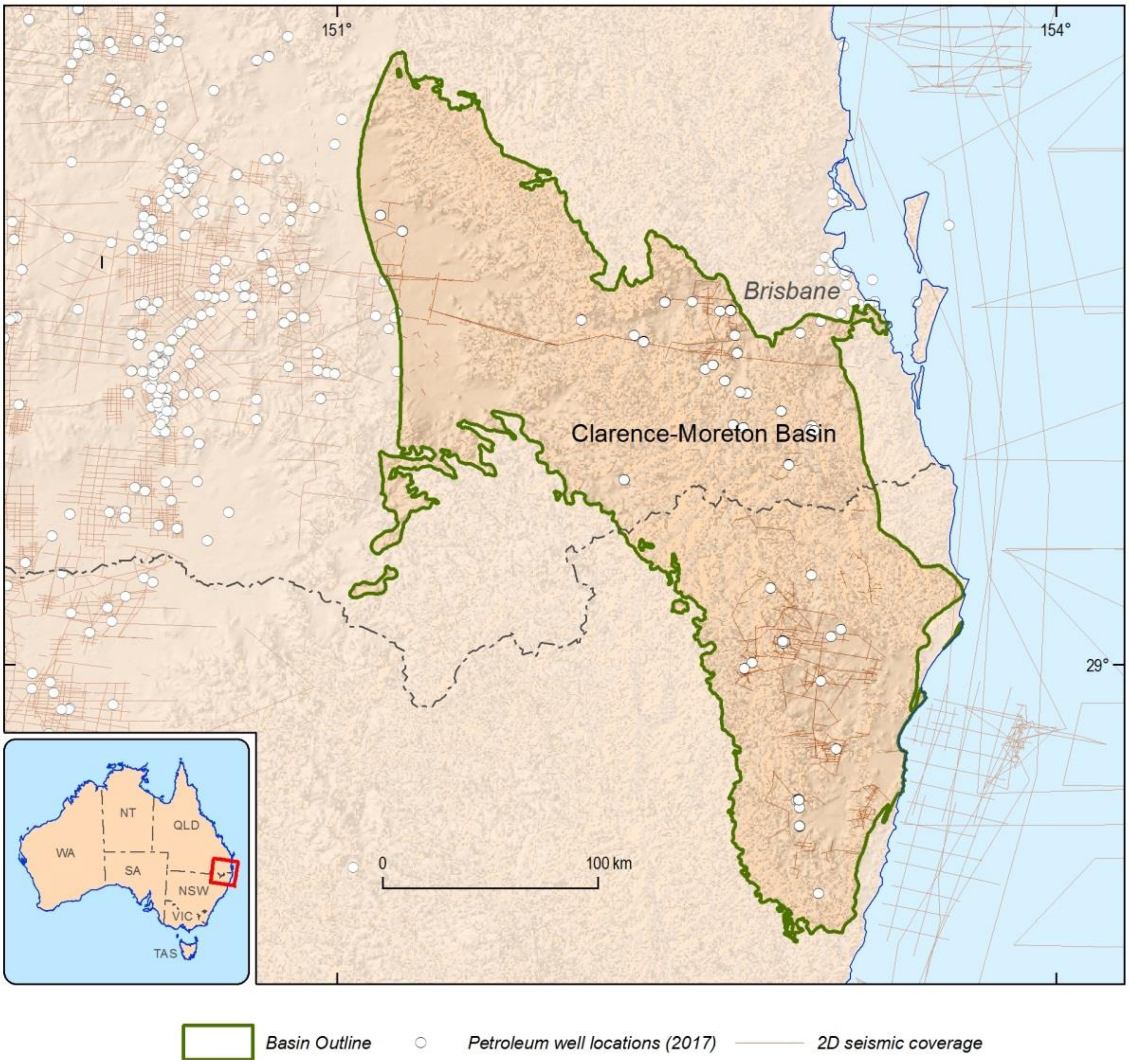

Figure C.27 Location of wells and seismic data, Clarence-Moreton Basin. Clarence-Moreton Basin outline from Stewart et al. (2013). Petroleum well data from DNRME (2017a) and DREMP (2017). Seismic data coverage from DNRME (2017b-d) and GSNSW (2017).

C.3.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Clarence-Moreton Basin is summarised in Table C.14.

The Clarence-Moreton Basin has a long history of petroleum exploration dating back to 1897, when gas flow was recorded from a coal borehole near Grafton. Despite the numerous gas and minor oil shows, the basin has remained lightly explored for conventional petroleum, with approximately 30 exploration holes drilled, mostly in the New South Wales part. Much of the onshore basin was under permit during the 2000s, with exploration activity increasingly targeting coal seam gas.

The Walloon Coal Measures and Koukandowie Formation contain oil-prone organic matter; both are oil mature in the central part of the onshore Clarence-Moreton Basin, but become rapidly overmature toward the eastern basin boundary (Powell et al., 1993; O'Brien et al., 1994b). Potential source rocks within the Clarence-Moreton Basin succession were generating hydrocarbons during the Late Cretaceous (100–80 ma), at the time of maximum burial and heat flow (Powell et al., 1993). Triassic potential source rocks within the underlying Ipswich and Nymboida basins are currently gas mature. Modelling indicates that the Ipswich Coal Measures would have commenced oil generation during the Early Jurassic, and all in situ oil would have been cracked to gas by the mid-Cretaceous (Russell, 1994).

O'Brien et al. (1994b) considered the southeastern Logan Sub-basin to be the most prospective area of the basin. Haselwood et al. (2004) noted that in the southeastern Queensland portion of the basin, low source rock volumes in some areas and low thermal maturities in other areas may have restricted the generation of large volumes of hydrocarbons over much of the basin, with the notable exception of areas around the South Moreton Anticline.

Metgasco undertook conventional and unconventional gas exploration in the basin during 2009–2013. In 2009, tight gas was encountered in the Gatton Sandstone in the Kingfisher E01 well, located south of Casino in northern NSW (Figure C.28; Metgasco, 2011). Metgasco planned to further test the Greater Mackellar structure with the drilling of Rosella E01, targeting the conventional play in the Ripley Road Sandstone discovered in Kingfisher E01, and tight sands in the Gatton Sandstone (Metgasco, 2014). However, the well did not proceed as drilling approval was suspended by the NSW Government (NSW Trade and Investment, 2014).

The Koukandowie and Raceview formations have been proposed as potential shale gas plays with a best estimate prospective recoverable shale gas resource of 11 Tcf and 10 Tcf respectively, over a prospective area of 4,407 km^2 (Table A.3; Table C.14; AWT International, 2013; see also AERA, 2018). Of these two formations, the Koukandowie Formation has a much higher proportion of fine-grained facies and higher organic carbon content (O'Brien et al., 1994b). Both may offer tight or basin-centred gas opportunities.

Data for the key unconventional hydrocarbon targets are summarised in Table C.15.

Although the results of Kingfisher E01 showed that the basin has some unconventional prospectivity, the basin is still in a very early phase of exploration. Significant further seismic data acquisition, drilling and testing would be required to improve our understanding of the shale and tight gas resource potential of this basin.

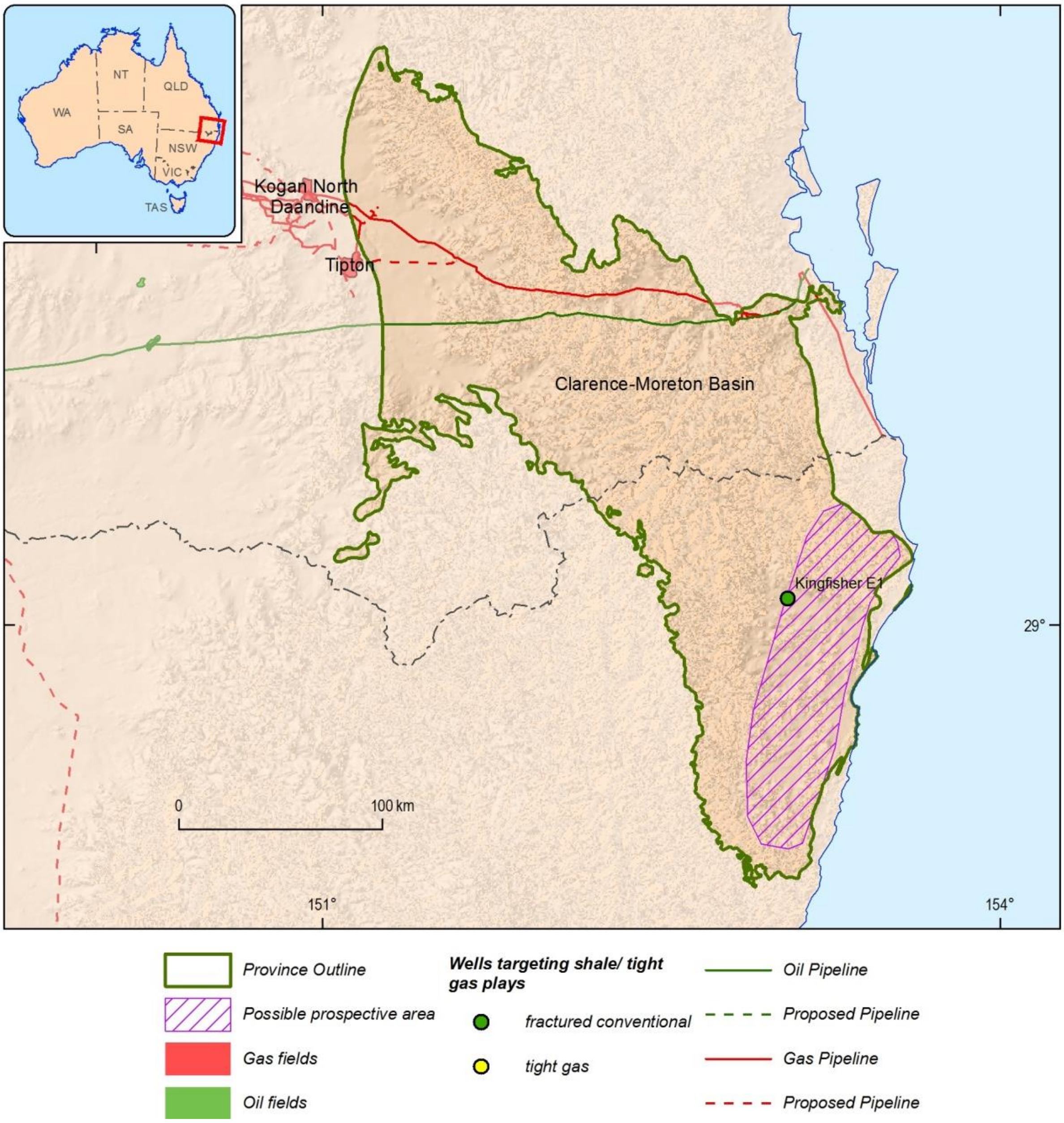

Figure C.28 Location of Kingfisher EO1 and approximate play extent based on maturity (O'Brien et al., 1994b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.15 Summary of shale and tight gas plays.

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity (Ro)	Play type	Exploration status
Koukandowie Fm	Early Jurassic	fluvial	200–1,200 m	<700	Type II/III; DOM	Generally 3.0–>20.0 (includes coal)	main oil to dry gas; 0.8–2.0%	Tight and/or shale gas	preliminary exploration; currently inactive
Gatton Sandstone	Early Jurassic	fluvial	500–1,500 m	<1,100 m	Raceview Fm, Ipswich Coal Measures	Generally <1.0–3.0; coal	main oil to dry gas; 0.8–2.4%	Tight gas	preliminary exploration; currently inactive
Raceview Fm	Late Triassic	fluvial	1200–2,400 m	<300	Type III	Generally <1.0–3.0	main oil to dry gas; 0.8–2.4%	Tight and/or shale gas	preliminary exploration; currently inactive

C.3.4 Gas market access and infrastructure

The Clarence-Moreton Basin is not a gas producing area; however, there is some existing pipeline infrastructure already in place, connecting Bowen and Surat basin gas facilities to Brisbane (AER, 2017). The basin is poorly to moderately well serviced in terms of road and rail access.

Figure C.29 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.16.

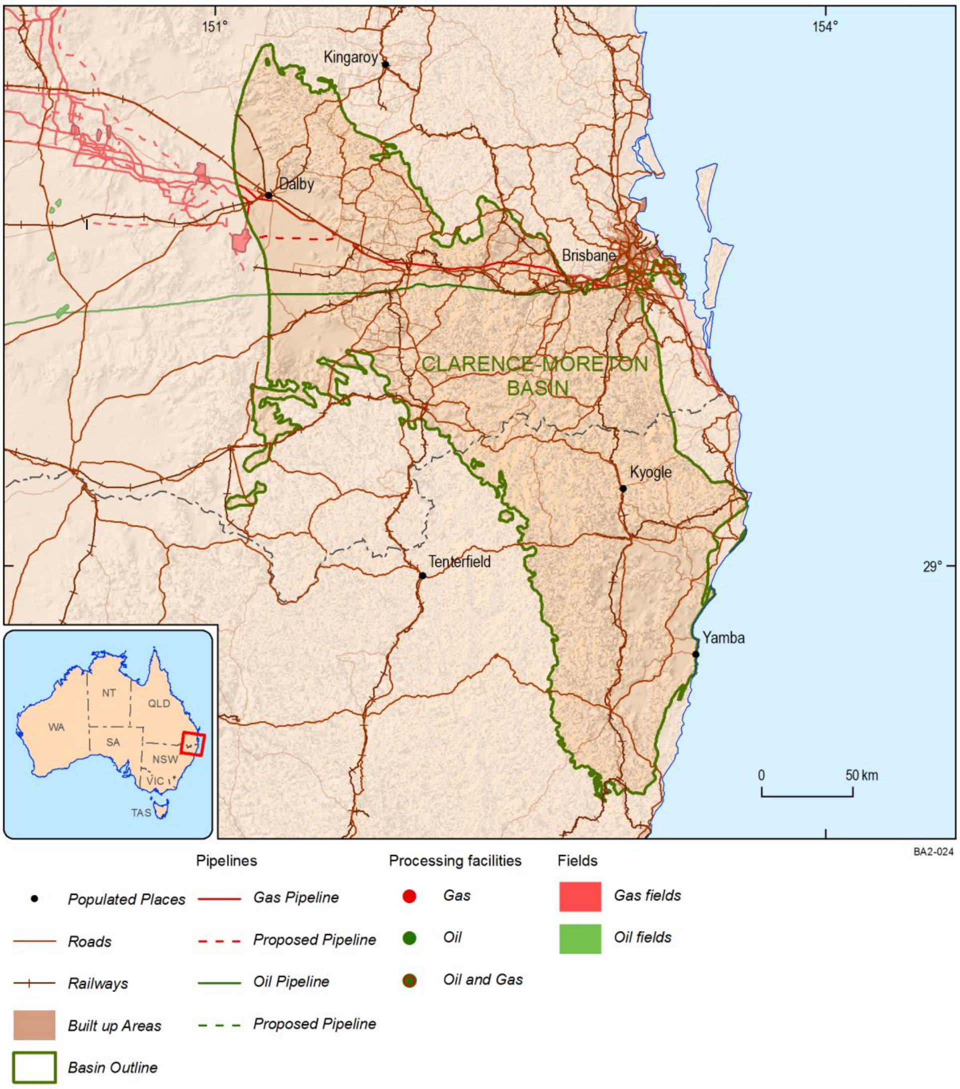

Figure C.29 Clarence-Moreton Basin and adjacent areas infrastructure, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.16 Summary of market access and infrastructure. Pipeline information from AER (2017). Oil and gas infrastructure from GA (2015a).

INFRASTRUCTURE	
Gas market	none
Gas pipelines	Wallumbilla to Brisbane Pipeline crosses northern part of basin
Gas processing facilities	none
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	>100 km
Road and rail access	Poorly to well serviced
Approximate development timeframe	7–>10 years

C.3.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia. There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland. However there are regulatory restrictions in New South Wales preventing or impeding onshore gas exploration and development. Further details regarding regulatory environment for each state are summarised below.

C.3.5.1 Queensland

The Queensland Government has no identified constraints to tight and shale gas resource drilling or production stimulation. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.3.5.2 New South Wales

In 2012, the NSW Gas Plan was published, following an independent review of CSG activities across the state (NSW Government, 2012a). This resulted in the introduction of the following measures, which are also relevant to tight and shale gas production:

- strategic regional land use policy, including the introduction of coal seam gas exclusion zones which prohibit coal seam gas activity in and within 2 kilometres of residential areas across the State and the North West and South West Growth Centres of Sydney, and;
- a code of practice for coal seam gas fracture stimulation, which includes banning of harmful chemicals (BTEX) in hydraulic fracturing operations (NSW Government, 2012b; Jeffrey, 2012).

To avoid any impact on water resources and to keep the fractures within the targeted area, each fracture stimulation must include:

- Identification of the rock types, the condition of aquifers and their distance from the target coal seams;
- Determination of the faults and stresses in the surrounding geology and the maximum pressure that can safely be applied; and
- Identification of the intervening strata and their porosity and permeability.

The Code also stipulates a risk assessment must be made, before each fracture stimulation, of the effects on public safety, land contamination, air pollution, noise and vibration, loss of well integrity, induced ground movements or seismicity and conflicts with existing land uses.

C.3.6 Hydrogeology and groundwater

The following section provides a brief summary of groundwater and surface water systems within the Clarence-Moreton Basin region. More detailed information is provided as part of the Bioregional assessments for the Clarence-Moreton and Maranoa Balonne Condamine Bioregional Assessments (http://www.bioregionalassessments.gov.au/). The following summary draws heavily on the work completed as part of these assessments.

C.3.6.1 Groundwater systems

Groundwater systems have been identified within Cenozoic to recent alluvial and volcanic sequences, and the Upper Triassic to Lower Cretaceous sedimentary rocks of the Clarence-Moreton Basin succession.

C.3.6.1.1 Alluvial aquifers

Alluvial aquifer systems are associated with major rivers and constitute some of the most productive groundwater sources in the Clarence-Moreton Basin. They include:

- Condamine alluvium—the most extensive alluvial groundwater system in the basin, it is situated west of the Great Dividing Range and overlies the northwestern boundary of the basin. The alluvium is generally between 20 and 60 m thick, increasing to 130 m south of Dalby (OGIA, 2016b). The most productive groundwater area occurs in sand and gravel within the central part of the mapped alluvium (Welsh et al., 2014). The Condamine Alluvium is used extensively for irrigation, industrial and stock and domestic purposes.
- Lockyer Valley alluvium—approximately 30 to 35 m in thickness, the unit is associated with the Lockyer Creek and its tributaries. The unit consists of coarse gravel towards the headwater areas in the southern tributaries, becoming finer to the northeast where the sedimentary grainsizes vary to include clay, sandy clay, sand, sandy gravel and gravel. The system is extensively utilised for irrigation (Rassam et al., 2014).
- Bremer River/Warrill Creek alluvium—aquifer material generally consists of sediments adjacent to existing channels and drainage lines (Pearce et al., 2007).

- Logan/Albert river alluvium—most groundwater is extracted where alluvium thickness ranges between 5 and 25 m. Sediments range from gravel to clay, generally in upwards-fining sequences (Rassam et al., 2014; Rudorfer 2009).
- Tweed River alluvium—this system comprises a shallow 'upriver' alluvial aquifer, characterised by coarse material (sands and some gravels), and the coastal floodplain alluvial aquifers, composed of relatively fine material (more sand and less gravel), often interspersed with silt and clay layers. The mean thickness is about 15 m, while better aquifers are in the thicker 20–35 m range (Rassam et al., 2014; Environmental Hydrology Associates, 2008).
- Richmond River alluvium—this consists of fluvial and estuarine gravel, sands, silts and mud, less than 35 m thick, that form unconfined to semi-unconfined aquifers with medium to high permeability (Rassam et al., 2014).

C.3.6.1.2 Volcanic aquifers

Main Range Volcanics

Main Range Volcanics (Oligocene–Miocene) aquifer system contains significant but variable amounts of groundwater. It is the most targeted aquifer in the basin. Groundwater is extracted for stock and domestic use, and to a lesser extent for irrigation and town water supplies. Aquifers generally consist of an upper, unconfined, weathered and fractured zone, and a lower, less extensive, semi-confined fractured zone with depth to water of between 11 and 41 m. Average aquifer thicknesses are in the order of 28 m (Welsh et al., 2014).

The aquifer system is thought to contribute recharge to the Condamine Alluvium and contributes baseflow to the headwaters of the Lockyer Creek, Bremer River, Warrill Creek and Logan River basins (Rassam et al., 2014).

Lamington Volcanics

The Lamington Volcanics (Miocene) form a major regional fractured rock aquifer system (more than 12,000 km^2) within the Clarence-Moreton Basin in southeast Queensland and northeast New South Wales (Raiber et al., 2016). A large proportion of recharge to the Lamington Volcanics discharges into streams locally, with short lag times and following short flow paths. A small proportion of this recharge percolates to deeper aquifers (Raiber et al., 2016).

Within the southeastern portion of the larger Lamington Volcanics, between Lismore and Ballina, is an area of intensive groundwater use – the Alstonville Plateau. Here, aquifers occur within the Lismore Basalt unit, which overlies older sedimentary rocks of the Clarence-Moreton basin (Rassam et al., 2014).

The Alstonville Plateau Basalt Groundwater Management Area has the greatest agricultural demand for groundwater on the North Coast of New South Wales (Brodie et al., 2002). Brodie et al. (2002) proposed a system comprising two main components:

- A shallow local-scale unconfined groundwater flow system operating within the soil profile and weathered or highly fractured basalt exceeding 40 m in thickness in some areas;

- A deeper intermediate-scale, semi-confined to confined groundwater flow system operating in interlayered and fractured horizons within the basaltic sequence.

C.3.6.1.3 Triassic to Jurassic Sedimentary Rock aquifers

The Upper Triassic to Lower Jurassic groundwater system includes aquifers within the Grafton Formation, Orara Formation, Walloon Coal Measures, Koukandowie Formation, Gatton Sandstone, and Woogaroo Subgroup. Of these, the Woogaroo Subgroup is the most widely utilised aquifer.

The Walloon Coal Measures, Koukandowie Formation, Gatton Sandstone and Woogaroo Subgroup are extensive across the basin. However, the majority of groundwater extraction from these units occurs in the north of the basin.

The Walloon Coal Measures are often considered as an aquitard on a regional scale due to their low permeability and storage capacity. However, at a local scale this unit is widely utilised for stock and domestic purposes.

The upper part of the Walloon Coal Measures, as well as the underlying Koukandowie Formation and Gatton Sandstone, are considered as low-permeability aquifers (Rassam et al., 2014).

C.3.6.2 Groundwater quality

Rassam et al. (2014) summarised groundwater salinity in the sedimentary and volcanic rock aquifers and alluvial aquifers with the Clarence-Moreton Bioregional Assessment area. The Condamine alluvium groundwater salinity is reported in OGIA (2016a). This information is summarised in Table C.17.

Table C.17 Salinity ranges for various hydrostratigraphic units

Hydrostratigraphic unit	Salinity minimum (mg/L)	Salinity maximum (mg/L)	Salinity mean (mg/L)
Condamine Alluvium	40	1,500	16,000
Lockyer Valley alluvium	91	1,904	18,000
Bremer/Warrill alluvium	~500	1,680*	~,6350
Richmond River alluvium	670*	-	1,675*
Clarence River alluvium		544	
Tweed River alluvium		427	
Main Range Volcanics	220		1,900
Lamington Volcanics		~580**	
Grafton Formation	360*		2,278*
Orara Formation	1,500		2,000
Walloon Coal Measures	1,500		19,475
Koukandowie Formation	359	4,248	14,496
Gatton Sandstone	333	6,452	24,294
Woogaroo Subgroup	961	2,518	4,147

* EC µS/cm converted TDS mg/l using 0.67 conversion factor

*** Approximate value based on Raiber et al. (2016)*

C.3.6.3 Groundwater flow

Generally, flow in the alluvial aquifers is topographically driven, following that of associated creeks and rivers, with groundwater water levels responding to recharge (Rassam et al., 2014). However, pumping and irrigation stresses that significantly alter water levels can impact groundwater flow directions, as is evident in the Condamine Alluvium (Figure C.30).

Groundwater flow in the Lockyer Valley, Bremer, and Logan-Albert rivers alluvial groundwater systems is to the northeast, and east in the Richmond River alluvium (Raiber et al., 2016).

The spatial coverage of groundwater levels within the sedimentary rock aquifer system is generally inadequate for determining groundwater flow across the basin. An exception is the norther part of the basin where sufficient data exist for the Walloon Coal Measures, Gatton Sandstone, and Woogaroo Subgroup. All three aquifers are similar, exhibiting northeasterly flow, apart from the northern portion of the Woogaroo Subgroup adjacent to the northern margin of the basin, where groundwater flow is to the southeast (Raiber et al., 2016).

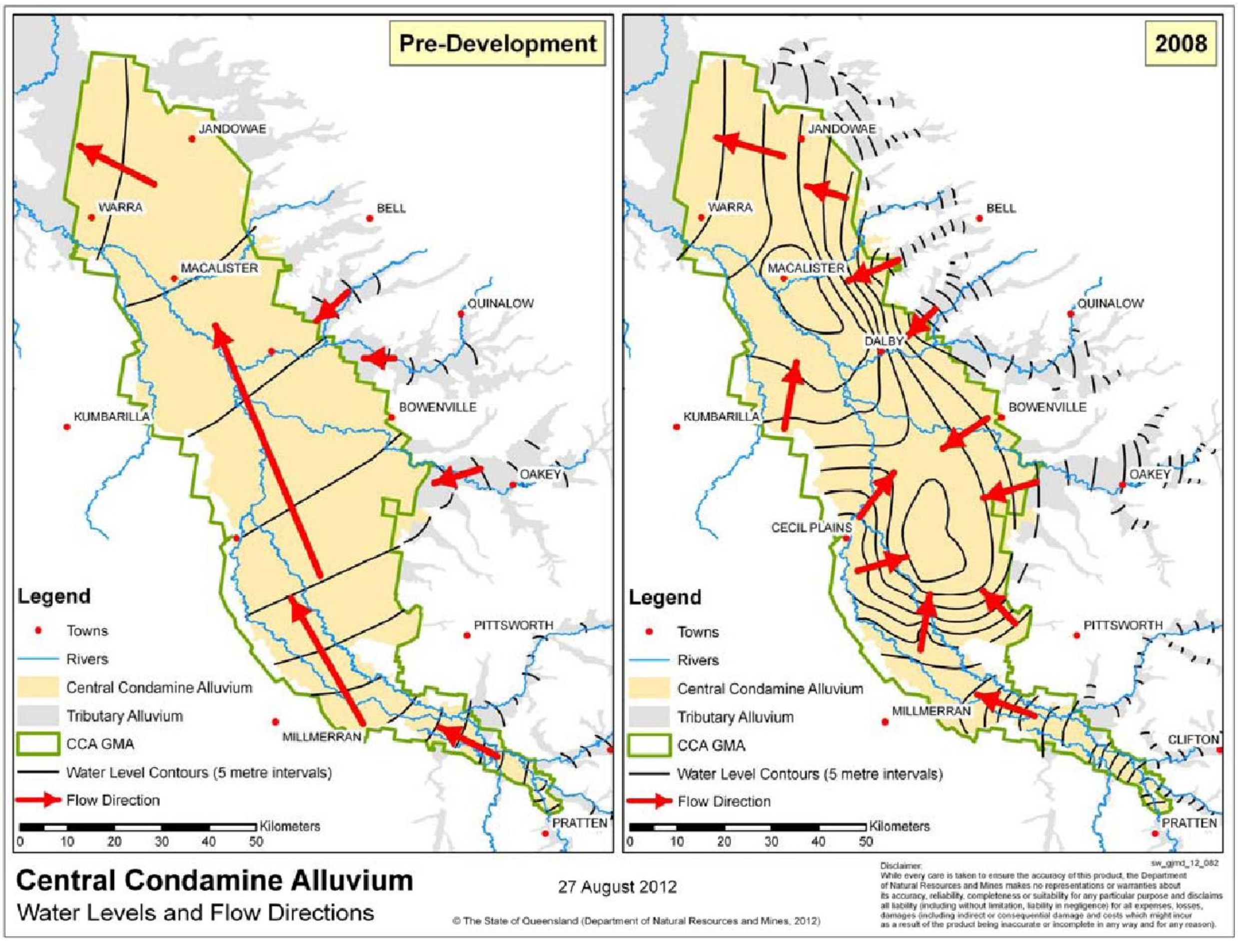

Figure C.30 Changes in groundwater flow (Source Figure 2 in Department of Natural Resources and Mines (2012)).

Toward the northwestern portion of the basin near Toowoomba, Ransley and Smerdon (2012) identified a subtle north-northeast to south-southwest trending basement ridge over which the

Clarence-Moreton sedimentary succession drapes. The ridge is thought to produce a potential groundwater divide resulting in westerly groundwater in flow in every horizon from basement up to the Walloon Coal Measures (Ransley and Smerdon, 2012). Within the Koukandowie Formation and Walloon Coal Measures the groundwater divide aligns generally with the edge of the escarpment of the Great Dividing Range (Ransley and Smerdon, 2012).

C.3.6.4 Groundwater Planning and Use

Groundwater planning and management is undertaken by the New South Wales and Queensland state governments for respective groundwater resources in the basin. Major groundwater resources and their respective water management plans are shown in Table C.18.

Table C.18 Water sharing plans and Water resource plans for various groundwater systems in and overlying the Clarence-Moreton basin

Groundwater system	Water sharing plan/Water resource plan
Lockyer Valley Alluvial Aquifer	Water Plan (Moreton) 2007 (Qld) (Queensland Government, 2007a)
Bremer/Warrill Alluvium	Water Plan (Moreton) 2007 (Qld) (Queensland Government, 2007a)
Richmond River Alluvium	Water Sharing Plan for the Richmond River Area Unregulated, Regulated and Alluvial Water Sources 2010 (NSW) (NSW Legislation, 2010a)
Clarence River Alluvium	Water Sharing Plan for the Clarence Unregulated and Alluvial Water Sources 2016 (NSW) (NSW Legislation, 2016a)
Tweed River Alluvium	Water Sharing Plan for the Tweed River Area Unregulated and Alluvial Water Sources 2010 (NSW) (NSW Legislation, 2010b)
Main Range Volcanics	Water Plan (Condamine and Balonne) 2004 (Qld) (Queensland Government, 2004)
Lamington Volcanics Grafton Formation Orara Formation Walloon Coal Measures	Water Sharing Plan for the North Coast Fractured and Porous Rock Groundwater sources 2016 (NSW), in particular the Clarence Moreton Basin, Alstonville Plateau and North Coast Volcanics groundwater sources. (NSW Legislation, 2016b)
Walloon Coal Measures Koukandowie Formation Gatton Sandstone	Water Plan (Great Artesian Basin) 2006 (Qld) (Queensland Government, 2006a)

The New South Wales Government has developed Water Sharing Plans to manage rivers and groundwater systems, which provide a legal basis for sharing water between the environment and consumptive purposes. For alluvial groundwater systems, water sharing plans consider the linkages between surface water and groundwater resources.

Sedimentary rock aquifers in New South Wales (Grafton Formation, Orara Formation and Walloon Coal Measures) are included in the Clarence-Moreton Basin groundwater source. This source has an estimated volume of 2,341 ML/yr for basic landholder rights (stock and domestic use) and a total licenced groundwater entitlement of 2,221 ML/yr.

The Alstonville Plateau groundwater source (Lismore Basalt) has basic landholder rights (stock and domestic use) of 2,014 ML/yr and a total licenced groundwater entitlement of 7,065 ML/yr.

North Coast volcanics groundwater source (Lamington Volcanics) has basic landholder rights (stock and domestic use) of 3402 ML/yr and a total licenced groundwater entitlement of 2505 ML/yr.

The Queensland Government's groundwater management and planning is covered by Water Resource Plans which are implemented through Resource Operation Plans.

Both the Main Range Volcanics and Condamine Alluvium are included as Groundwater Sustainable Diversion Limit (SDL) resource units in the Commonwealth's Basin Plan 2012 for the Murray Darling Basin (Federal Register of Legislation, 2012). Under the Basin Plan, the Condamine Alluvium is divided into the Upper Condamine Alluvium (Central Condamine Alluvium) and the

Upper Condamine Alluvium (Tributaries) which have SDL and Base Diversion Limits (BDL) of 81.4 GL/yr and 46 GL/yr, and 45.5 GL/yr and 40.5 GL/yr respectively. The Main Range Volcanics is referred to as the Upper Condamine Basalts and has an SDL and BDL of 79 GL/yr (Welsh et al., 2014).

Table C.19 presents information from the NGIS (BoM, 2016) showing summary information of registered bores in the basin.

Table C.19: Summary of groundwater bores and water use in and above the Clarence-Moreton Basin.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	36,480 (0.95)	
Purposes of registered bores (Top 5, number)	Unknown	26,506
	Irrigated Agriculture	4,889
	Household	2,635
	Stock	1,888
	Community water supply	443
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 4.9 Median: 33 90th Percentile: 80	

C.3.7 Surface water hydrology and water quality

C.3.7.1 Surface Water Systems

According to the Bureau of Meteorology's Geofabric, the Clarence-Moreton Basin is covered by parts of three drainage divisions: the North East Coast, the South East Coast and easternmost portion of the Murray-Darling Basin (BoM, 2014). A summary of the river regions within each division is included in Table C.20 and presented in Figure B.13.

Table C.20 River regions overlying the Clarence-Moreton Basin, grouped by drainage division, as classified in the Bureau of Meteorology's Geofabric (BoM, 2014)

North East Coast	South East Coast	Murray-Darling Basin
Brisbane River	Bellinger River*	Condamine-Culgoa rivers*
Burnett River*	Brunswick River*	
Logan-Albert rivers	Clarence River	
South Coast*	Richmond River	
	Tweed River	

** River regions with the majority of area outside the boundary of the Clarence-Moreton Basin*

Many of the river regions within the basin are subject to extreme rainfall events, commonly associated with cyclonic activity. Consequently, a number of rivers in the basin are susceptible to periodic flooding.

River regions in which significant licensed water harvesting by instream interception for irrigation include: Condamine-Culgoa rivers, Richmond River, Logan-Albert rivers and the Brisbane River.

C.3.7.2 Surface Water Quality

Summary water quality information including sediment loading, nutrient and phosphorus export for river regions are presented in Rassam et al. (2014). Electrical conductivity (salinity) measurements are monitored at a number gauging station throughout the region. However, there is no comprehensive monitoring program that covers all key rivers and tributaries (Rassam et al., 2014). A limited amount of salinity information for each river region is available in Rassam et al. (2014) and is reported below:

- Brisbane River—mean salinity in Laidley, Lockyer and Tenthill Creeks between 1995 and 2003 was 470, 1,700 and 1,378 µS/cm.
- Tweed River—median salinity, as inferred from electrical conductivity, was very low (0–200 µS/cm) and that values remained below 400 µS/cm for 80% of the time.
- Brunswick River—low salinity (electrical conductivity of 0–200 µS/cm).
- Richmond River—at most of the locations, median electrical conductivity values were less than 400 µS/cm. Some steams have median electrical conductivity of between 400 and 800 µS/cm.
- Clarence River—median salinity values in much of the upper parts of the river basin were less than 200 µS/cm.

C.3.7.3 Surface Water Flow

With the exception of the Tweed and Brunswick river regions, all river regions have multiple gauging stations measuring stream flow. However, not all river region gauging sites are within the Clarence-Moreton Basin. Table C.21 shows the maximum mean daily flow at a representative gauge within each river region.

Table C.21 Mean daily flow at stream gauge sites for some locations within the extent of the Clarence-Moreton Basin

River Region	Gauging Station	Mean daily flow (ML)
Brisbane River	Lockyer Creek at O'Reillys Weir	619
Logan-Albert rivers	Logan River at Yarrahappini	869
South Coast Basin	Back Creek at Beechmont	13
Richmond River	Richmond River at Casino	1,617
Clarence River	Clarence River at Lilydale	9,295
Condamine-Culgoa rivers	Condamine River at Loudouns Bridge	12,380

C.3.7.4 Surface water Planning and Use

A number of river basins have management plans, these are presented in Table C.22.

Table C.22 Management plans for various river basins overlying the Clarence-Moreton Basin

River Basin	Management plan
Brisbane River basin	Water Plan (Moreton) 2007 (Qld) (Queensland Government, 2007a)
Logan-Albert rivers basin	Water Resource (Logan Basin) Plan 2007 (Qld) (Queensland Government, 2007b)
South Coast basin	Water Resource (Gold Coast) Plan 2006 (Qld) (Queensland Government, 2006b)
Tweed River basin	Water Sharing Plan for the Tweed River Area Unregulated and Alluvial Water Sources 2010 (NSW) (NSW Legislation, 2010b)
Brunswick River basin	Water Sharing Plan for the Brunswick Unregulated and Alluvial Water Sources 2016 (NSW) (NSW Legislation, 2016c)
Richmond River basin	Water Sharing Plan for the Richmond River Area Unregulated, Regulated and Alluvial Water Sources 2010 (NSW) (NSW Legislation, 2010a)
Clarence River basin	Water Sharing Plan for the Clarence River Unregulated and Alluvial Water Sources 2016 (NSW) (NSW Legislation, 2016a)
Condamine-Culgoa rivers basin	Water Plan (Condamine and Balonne) 2004 (Qld) (Queensland Government, 2004)

C.3.8 Groundwater–Surface Water Interactions

The unconfined alluvial aquifer systems are typically in direct connection with surface water features such as streams and wetlands, and there is likely connection between rivers that have incised into rock aquifers such as the Main Range Volcanics and Walloon Coal Measures. Acid sulfate soils are associated with coastal sediments in the Tweed, Clarence and Richmond River catchments, as a result of falling groundwater levels producing oxidising conditions (Rassam et al., 2014).

C.3.9 Environmentally sensitive areas

Within the Clarence-Moreton Basin there are 331 km^2 of Listed Nationally Important Wetlands, 2770 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential), and the Ramsar listed Moreton Bay wetland. A total of 3,587 km^2 of protected areas (such as national parks) are listed. Table C.23 provides details of these assets.

Table C.23 Environmental Assets occurring above the Clarence-Moreton Basin.

ENVIRONMENTAL ASSETS		
Ramsar Wetlands	Moreton Bay	
Nationally Important Wetlands Top 5 by area (area km^2)	Upper Coldstream	98
	Clarence River Estuary	55
	Greenbank Army Training Area C	40
	Bundjalung National Park	28
	Everlasting Swamp	26
	TOTAL WETLAND AREA	331
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	National Park	2,455
	Nature Reserve	413
	Protected Area	357
	State Conservation Area	215
	Nature Refuge	112
	TOTAL PROTECTED AREA	3,587
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	2770	

C.3.10 Social factors/constraints

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in the table below (Table C.24).

Table C.24 General and social characteristics of the land overlying the Clarence-Moreton Basin.

GENERAL CHARACTERISTICS		
Population	1,000,378	
Major population centres (Top two)	Brisbane suburbs, Toowoomba	
Land use types Top five by area (area km^2)	Grazing native vegetation	12,515
	Grazing modified pastures	6,230
	Dryland cropping	5,413
	Minimal use	3,901
	Nature Conservation	2,879
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	1,954	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

Brodie RS, Green R and Graham M (2002) Mapping groundwater-dependent ecosystems: a case study in the fractured basalt aquifers of the Alstonville Plateau. In New South Wales, Australia. Proceedings of the IAH 2002 Conference, Darwin.

CAPAD (2016) Collaborative Australian Protected Area Database, 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Core (2014) Gas reserves and resources, eastern and southeastern Australia. Core Energy Group report to the Australian Energy Market Operator. Viewed 09/08/2017, <https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2015/Core--Gas-Reserves-and-Resources.pdf>.

DNRM (Department of Natural Resources and Mines) (2012) Upper Condamine Alluviums groundwater system, Background summary. Viewed 18/07/2017, <https://www.dnrm.qld.gov.au/__data/assets/pdf_file/0003/104844/upper-condamine-alluvium-factsheet.pdf>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DREMP (Division of Resources and Energy, Minerals and Petroleum, New South Wales) (2017) Drillholes and wells. Viewed 16/01/2018, <http://dwh.minerals.nsw.gov.au/CI/warehouse>.

Doig A and Stanmore P (2012) The Clarence-Moreton Basin in New South Wales; geology, stratigraphy and coal seam characteristics. In: Mares T (ed.) Eastern Australasian Basins Symposium IV. Petroleum Exploration Society of Australia, Special Publication.

Environmental Hydrology Associates (2008) Tweed District Water Supply Augmentation Options Study: Input to Stage 1 – Identification of Feasible Options – Groundwater Supply. Report prepared for MWH Australia Pty Ltd. Report Number GW-08-02-REP-001 Rev A, 22 July 2008.

Federal Register of Legislation (2012) "Basin Plan 2012", instrument under the Water Act 2007 (Cwlth), affecting the Murray-Darling Basin, compiled 23 January 2017. Viewed 29/09/2017, < https://www.legislation.gov.au/Details/F2017C00078>.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

GSNSW (Geological Survey New South Wales) (2017) NSW seismic lines. Viewed 11/08/2017, <https://geonetwork.geoscience.nsw.gov.au/geonetwork/srv/eng/catalog.search#/metadata/f8bff11246816b6d8f31305b0b66a7997ff6870b>.

Haselwood R, Deighton I and Hamilton L (2004) An appraisal of the hydrocarbon potential of the southeast Clarence-Moreton Basin in Queensland. In: Boult PJ, Johns DR and Lang SC (eds), Eastern Australasian Basins Symposium II. Petroleum Exploration Society of Australia, Special Publication, 331–337.

Ingram FT and Robinson VA (1996) Petroleum prospectivity of the Clarence-Moreton Basin in New South Wales. New South Wales Department of Mineral Resources, Petroleum Bulletin, 3, Sydney.

Jeffrey R (2012) Hydraulic fracturing for coal seam gas (CSG) stimulation in New South Wales. Report prepared by CSIRO for the Office of the NSW Chief Scientist & Engineer. Viewed 16/01/2018, <http://www.chiefscientist.nsw.gov.au/__data/assets/pdf_file/0005/56849/Report_NSW_OCSE_May2012_FracturingCoal.pdf>.

Korsch RJ, O'Brien PE, Sexton MJ, Wake-Dyster KD and Wells AT (1989) Development of Mesozoic transtensional basins in easternmost Australia. Australian Journal of Earth Sciences, 36, 13–28.

Metgasco (2011) Quarterly activities report: quarter ended 31 December 2010. ASX/Media release. Viewed 22/01/2018, <http://www.asx.com.au/asxpdf/20110131/pdf/41whjc35hlh7cz.pdf>.

Metgasco (2014) Metgasco selects rig contractor for Rosella E01. ASX/Media release. Viewed 22/01/2018, <http://www.asx.com.au/asxpdf/20140214/pdf/42mqk629mcldfg.pdf>.

NSW Chief Scientist and Engineer (2014) Independent Review of Coal Seam Gas Activities in NSW. Information paper: Fracture stimulation activities. Viewed 22/01/2018, <http://www.chiefscientist.nsw.gov.au/__data/assets/pdf_file/0008/56924/140930-Final-Fracture-Stimulation.pdf>.

NSW Government (2012a) NSW Gas Plan: protecting what's valuable, securing our future. Viewed 16/01/2018, <http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0005/534830/NSW-Gas-Plan.pdf>.

NSW Government (2012b) Code of practice for coal seam gas: Fracture stimulation activities. Viewed 16/01/2018, <http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0018/516114/Code-of-Practice-for-Coal-Seam-Gas-Fracture-Stimulation.pdf>.

NSW Legislation (2010a) "Water Sharing Plan for the Richmond River Area Unregulated, Regulated and Alluvial Water Sources 2010", subordiante legislation under the Water Management Act 2000 (NSW), current as of 19 February 2016. Viewed 29/09/2017, <https://legislation.nsw.gov.au/#/view/subordleg/2010/702/full>.

NSW Legislation (2010b) "Water Sharing Plan for the Tweed River Area Unregulated and Alluvial Water Sources 2010", subordinate legislation under the Water Management Act 2000 (NSW), current as of 1 October 2011. Viewed 29/09/2017, <https://legislation.nsw.gov.au/#/view/regulation/2010/704/full>.

NSW Legislation (2016a). "Water Sharing Plan for the Clarence River Unregulated and Alluvial Water Sources 2016", subordinate legislation under the Water Management Act 2000 (NSW), current as of 6 January 2017. Viewed 29/09/2017, <https://www.legislation.nsw.gov.au/#/view/subordleg/2016/381/full>.

NSW Legislation (2016b) "Water Sharing Plan for the North Coast Fractured and Porous Rock Groundwater Sources 2016", subordinate legislation under the Water Management Act 2000 (NSW), current as of 1 July 2016. Viewed 29/09/2017, <https://legislation.nsw.gov.au/#/view/regulation/2016/375/full>.

NSW Legislation (2016c) "Water Sharing Plan for the Brunswick Unregulated and Alluvial Water Sources 2016", subordinate legislation under the Water Management Act 2000 (NSW), Current as at 6 January 2017. Viewed 05/12/2017, <https://www.legislation.nsw.gov.au/#/view/subordleg/2016/386/full>.

NSW Trade and Investment (2014) PEL 16 Rosella E01 Gas Exploration Well - Suspension of Activity Approval. Viewed 29/08/2017, <http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0006/520368/metgasco-26-jun-2014.pdf>.

O'Brien PE, Korsch RJ, Wells AT, Sexton MJ and Wake-Dyster K (1994a) Structure and tectonics of the Clarence-Moreton Basin. In: Wells AJ and O'Brien PE (eds), Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation, Bulletin, 241, 195–216.

O'Brien PE, Powell TG and Wells AT (1994b) Petroleum potential of the Clarence-Moreton Basin. In: Wells AJ and O'Brien PE (eds), Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation, Bulletin, 241, 277–290.

OGIA (Office of Groundwater Impact Assessment) (2016a) Department of Natural Resources Hydrogeological conceptualisation report for the Surat Cumulative Management Area August 2016.

OGIA (Office of Groundwater Impact Assessment) (2016b) Underground Water Impact Report for the Surat Cumulative Management Area Department of Natural Resources and Mines.

Pearce BR, McMahon GA and Hansen JWL (2007) Hydrogeological investigation of the Bremer River sub-Catchment, southeast Queensland Australia. Water Assessment Group, Department of Natural Resources and Water, Brisbane. QNRM06251.

Powell TG, O'Brien PE and Wells AT (1993) Petroleum prospectivity of the Clarence-Moreton Basin, eastern Australia: a geochemical perspective. Australian Journal of Earth Sciences, 40(1), 31–44.

Queensland Government (2004) "Water Plan (Condamine and Balonne) 2004", legislation under the Water Act 2000 (Qld), Current as at 2 September 2017. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/inforce/current/sl-2004-0151>.

Queensland Government (2006a) "Water Plan (Great Artesian Basin) 2006", legislation under the Water Act 2000 (Qld), current as at 3 July 2017. Viewed 04/08/2017, <https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf>.

Queensland Government (2006b) "Water Resource (Gold Coast) Plan 2006", legislation under the Water Act 2000 (Qld), Reprinted as in force on 4 May 2007, Reprint No. 1A. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/inforce/2007-05-04/sl-2006-0321>.

Queensland Government (2007a) "Water Plan (Moreton) 2007", legislation under the Water Act 2000 (Qld), current as at 29 September 2017. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/inforce/current/sl-2007-0031>.

Queensland Government (2007b) "Water Resource (Logan Basin) Plan 2007", legislation under the Water Act 2000 (Qld), current as at 27 June 2014. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/2014-06-27/sl-2007-0025>.

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 22/01/2018, <https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells>.

Raiber M and Cox ME (2012) Linking three-dimensional geological modelling and multivariate statistical analysis to define groundwater chemistry baseline and identify inter-aquifer connectivity within the Clarence-Moreton Basin, southeast Queensland, Australia. In: Mares, T (ed.), Eastern Australasian Basins Symposium IV. Petroleum Exploration Society of Australia, Special Publication.

Raiber M, Cui T, Pagendam D, Rassam D, Gilfedder M, Crosbie R, Marvanek S and Hartcher M (2016) Observations analysis, statistical analysis and interpolation for the Clarence-Moreton bioregion. Product 2.1-2.2 from the Clarence-Moreton Bioregional Assessment. Department of the Environment and Energy, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Ransley TR and Smerdon BD (eds) (2012) Hydrostratigraphy, hydrogeology and system conceptualisation of the Great Artesian Basin. A technical report to the Australian Government from the CSIRO Great Artesian Basin Water Resource Assessment. CSIRO Water for a Healthy Country Flagship, Australia. 285 pp.

Rassam D, Raiber M, McJannet D, Janardhanan S, Murray J, Gilfedder M, Cui T, Matveev V, Doody T, Hodgen M and Ahmad ME (2014) Context statement for the Clarence-Moreton bioregion. Product 1.1 from the Clarence-Moreton Bioregional Assessment. Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Raymond OL, Gallagher R and Highet LM (2012) Surface geology of Australia, 1:2 500 00 scale (2012 edition. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!b4088aa1-f875-2444-e044-00144fdd4fa6>.

Rudorfer V (2009) Groundwater Flow Model of the Logan River Alluvial Aquifer System, Josephville, South East Queensland. Queensland University of Technology, thesis for Master of Applied Science. https://eprints.qut.edu.au/29322/1/Vivien_Rudorfer_Thesis.pdf

Russell NJ (1994) A palaeogeothermal study of the Clarence-Moreton Basin. In: Wells AJ and O'Brien PE (eds) Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation Bulletin 241, 237–276.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Stewart JR and Alder JD (1995) New South Wales Petroleum Potential. New South Wales Department of Mineral Resources, Coal and Petroleum Branch, Bulletin, 1, Sydney.

Stephenso, AE and Burc, GJ (2004) Preliminary evaluation of the petroleum potential of Australia's central eastern margin. Geoscience Australia, Record, 2004/06, Canberra

Totterdell JM, Hall L, Hashimoto T, Owen K and Bradshaw MT (2014) Petroleum geology inventory of Australia's offshore frontier basins. Record 2014/09. Geoscience Australia.

Wells AJ and O'Brien PE (eds) (1994) Lithostratigraphic framework of the Clarence-Moreton. In: Wells AJ and O'Brien PE (eds) Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation Bulletin 241, 4–47.

Welsh W, Herron N, Rohead-O'Brien H, Ransley T, Aryal S, Mitchell P, Buckerfield S and Marshall S (2014) Context statement for the Maranoa-Balonne-Condamine subregion. Product 1.1 for the Maranoa-Balonne-Condamine from the Northern Inland Catchments Bioregional Assessment. Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Willis IL (1994) Stratigraphic implications of regional reconnaissance observations in the Clarence-Moreton Basin, New South Wales. In: Wells AJ and O'Brien PE (eds), Geology and petroleum potential of the Clarence-Moreton Basin, New South Wales and Queensland. Australian Geological Survey Organisation, Bulletin, 241, 48–71.

C.4 Cooper Basin

Table C.25 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	Queensland, South Australia
Area	126,950 km2
Maximum basin depth	>4,500 m
Maximum sediment thickness	Up to 2,500 m
Age range	Late Carboniferous to Middle Triassic
Depositional setting	Glacial, meandering fluvial to flood basin and lacustrine environments
Regional structure	Contractional and extensional events, producing faulted anticlines, ridges and basin depocentres
Overlying basins	Eromanga Basin, Eyre Basin
Underlying basins	Warburton Basin, Warrabin Trough (Adavale Basin equivalent)
EXPLORATION STATUS	
Seismic lines	>81,000 line km of 2D seismic; >10,000 km2 of 3D seismic
Number of petroleum wells	>3000
Exploration status – conventional	Producing/mature
Exploration status – coal seam gas	Under assessment
Exploration status – shale/ tight gas	Under-explored
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Gondwanan)
Prospectivity	High
Conventional discoveries	256 gas fields and 166 oil fields currently in production
Hydrocarbon production – total to date	6.54 Tcf cumulative conventional gas production; no CSG (includes overlying Eromanga Basin; current to 2014; AERA, 2018)
2P Reserves	1.54 Tcf conventional; no CSG (includes overlying Eromanga Basin; current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	3.2 Tcf conventional; 0.4 Tcf CSG; see below for shale/ tight gas (includes overlying Eromanga Basin; current to 2014; AERA, 2018)
Undiscovered resource estimates	0.9 Tcf conventional; see below for shale and tight gas (at P50; AERA, 2018)

PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Tight gas, shale gas, deep coal
No of wells targeting shale/ tight gas plays	>40
Production – shale/ tight gas	Minor shale and tight gas production from Moomba 191, 193H and 194 (Santos, 2012, 2013a, b)
2P Reserves – shale/ tight gas	None currently reported
Remaining resources (reserves + contingent resources) – shale/ tight gas	8.74 Tcf shale gas; 0.84 Tcf tight gas (includes overlying Eromanga Basin; AERA, 2018)
Undiscovered resource estimates – shale/ tight / deep coal gas	• Technically recoverable shale gas in the REM of 92 Tcf, including 89 Tcf in the Nappamerri Trough (prospective area - associated gas 625 mi2, wet gas 555 mi^2, dry gas 3,525 mi^2) and 4 Tcf in the Patchawarra Trough (prospective area - associated gas 1,010 mi^2, wet gas 1,150 mi^2, dry gas 170 mi^2) (EIA, 2013) • Best estimates on recoverable shale gas in the REM of 14 Tcf over a prospective area of 3,604 km^2 for wet gas and 35 Tcf over a prospective area of 9,106 km^2 for dry gas (AWT International, 2013) • Potentially recoverable shale gas-in-place (5% recovery factor at P50) of 6.9 Tcf in the Roseneath Shale (prospective area wet gas 3,834 km^2, dry gas 3,403 km^2) and Murteree Shale (prospective area wet gas 3,454 km^2, dry gas 3,291 km^2) (AERA, 2018) • Potentially recoverable tight gas-in-place (5% recovery factor at P50) of 50.9 Tcf in the Patchawarra Formation (prospective area wet gas 14,426 km^2, dry gas 3,417 km^2), Epsilon Formation (prospective area wet gas 5,413 km2, dry gas 3,401 km^2), Daralingie Formation (prospective area wet gas 4,691 km^2, dry gas 3,102 km^2) and Toolachee Formation (prospective area wet gas 15,070 km^2, dry gas 2,725 km^2) (AERA, 2018) • 2C resources of 0.421 Tcf for Patchawarra Formation coals (PEL 90) in the Arrabury Trough (Senex, 2013) • Deterministic sales of gas in place for Permian coal of 113.77 Tcf (Core Energy Group, 2016)
Hydrocarbon shows, tests – shale/ tight gas	Production from Moomba 191, 193H and 194 (Santos, 2012, 2013a, b)

C.4.1 *Basin geology*

The Cooper Basin is a Late Carboniferous–Middle Triassic intracratonic basin in northeastern South Australia and southwestern Queensland covering an area of approximately 127,000 km^2 (Figure C.31; Table C.25; Gravestock et al., 1998; Carr et al., 2016; Jell, 2013). It unconformably overlies lower Paleozoic sediments of the Warburton Basin in the southwest and Devonian sediments associated with the Adavale Basin in the northeast (Gravestock and Jensen-Schmidt, 1998; Draper, 2002; Radke, 2009; Stewart et al., 2013; Hall et al., 2015). The Cooper Basin is entirely and disconformably overlain by the Jurassic–Cretaceous Eromanga Basin, which in turn is unconformably overlain by the Cenozoic Lake Eyre Basin (Gravestock et al., 1998; Cook et al., 2013; Cook and Jell, 2013; Stewart et al., 2013).

The Cooper Basin is divided into two areas by the Jackson Naccowlah Pepita (JNP) Trend, one in the northeast and the other in the southwest (Figure C.31; McKellar, 2013; Hall et al., 2015). These areas have distinctly different structural and sedimentary histories. Depocentres in the southwestern Cooper Basin are generally deeper and contain a thicker and more complete Permian succession than the northern part of the basin (Hill and Gravestock, 1995; McKellar, 2013). The three major troughs in the southwest (Patchawarra, Nappamerri and Tenappera) are separated by the Gidgealpa-Merrimelia-Innamincka (GMI) and Murteree ridges (Figure C.31), which strike northeast-southwest, approximately parallel to the main depositional axis of the basin (Gravestock and Jensen-Schmidt, 1998). In the northeastern Cooper Basin, the Permian succession is thinner, and the major depocentres, including the Windorah Trough and Ullenbury Depression, are typically less well mapped (Draper, 2002; McKellar, 2013).

The stratigraphy of the Cooper Basin is divided into two groups—the Pennsylvanian to upper Permian Gidgealpa Group and the top Permian to Middle Triassic Nappamerri Group (Figure C.32). The formations associated with the main unconventional play types all lie within the Gidgealpa Group and are discussed briefly below.

The Patchawarra Formation comprises interbedded sandstone, siltstone, shale and coal. The formation is present across the entire basin and is the thickest unit of the Gidgealpa Group, reaching 680 m in the Nappamerri Trough. Lithofacies distribution patterns suggest deposition within a high sinuosity fluvial system that included floodplains, peat swamps, and lakes.

The Murteree Shale comprises black to dark grey-brown argillaceous siltstone with minor fine-grained sandstone and was deposited in a deep lake environment with restricted circulation (Alexander et al., 1998; Gray and McKellar, 2002). The Epsilon Formation comprises fine to medium-grained sandstone interbedded with carbonaceous siltstone and shale, and occasional coals (Gatehouse, 1972; Price, 1997; Alexander et al., 1998; Gray and McKellar, 2002). It consists of an aggradational lacustrine delta sequence, deposited under conditions of differential subsidence. The Roseneath Shale comprises light to dark brown-grey siltstone, mudstone and minor fine-grained sandstone and was deposited in a lacustrine environment similar to the Murteree Shale (Price, 1997; Alexander et al., 1998; Gray and McKellar, 2002). The Daralingie Formation comprises interbedded carbonaceous and micaceous siltstone, mudstone, coal and minor sandstone. All four formations are generally restricted to the southern Cooper Basin (Hall et al., 2015).

The Toolachee Formation comprises interbedded fine to coarse-grained quartzose sandstone, mudstone, carbonaceous shale with thin coal seams and conglomerates (Price, 1997; Alexander et al., 1998; Gray and McKellar, 2002; Nakanishi and Lang, 2001). The Toolachee Formation was deposited in fluvial environments during an interval of renewed basin subsidence. Clastic deposition occurred in ephemeral lakes and on the floodplains, while coal formed in swamps.

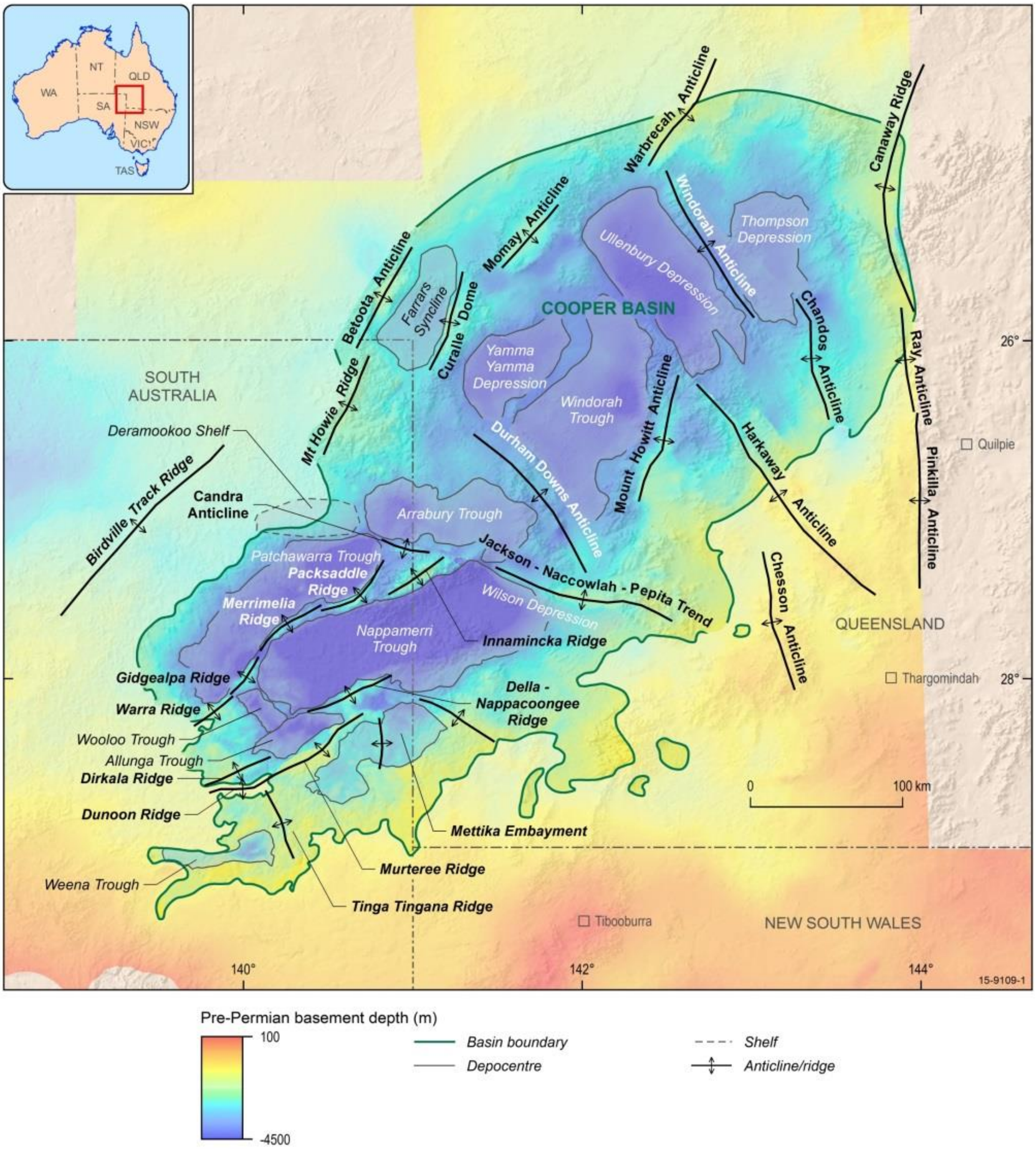

Figure C.31 Cooper Basin structural elements overlain on the top pre-Permian basement horizon (Hall et al., 2015; Carr et al., 2016), with the basin outline from Stewart et al., (2013).

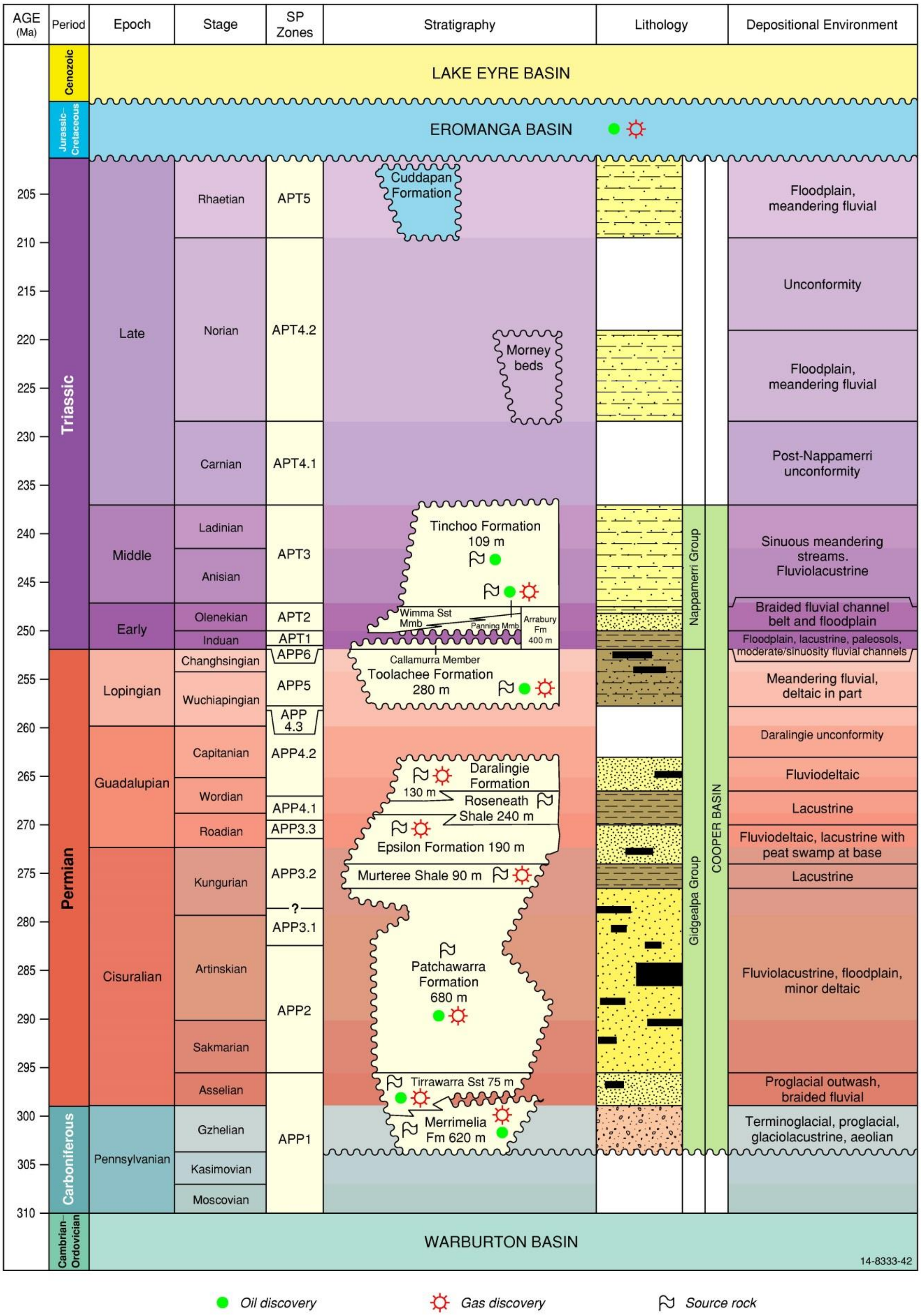

Figure C.32 Stratigraphy of the Cooper Basin showing depositional facies, conventional petroleum occurrences and identified source rocks (Hall et al., 2015; Carr et al., 2016).

C.4.2 Petroleum data coverage

The Cooper Basin is extensively explored and has the richest datasets of any onshore sedimentary basin in Australia. Since 1959, there have been over 3000 petroleum wells drilled within the Cooper Basin, which have targeted oil and gas in Permian and Triassic formations (Figures C.32 and C.33; DNRME, 2017a; DPCSA, 2017d).

Seismic data coverage is extensive across the Cooper Basin, collected from the 1960s until the present. More than 81,000 line-kilometres of 2D and 10,000 km^2 of 3D seismic have been acquired (Carr et al., 2016; DNRME, 2017b-d; DPCSA, 2017a, e). Over time, improvements in seismic technologies have greatly enhanced the understanding of subtle structural features and plays within the basin.

Geophysical data are available across most of the basin, including gravity (>4 km station spacing) and aeromagnetics (<400 m line spacing; Carr et al., 2016).

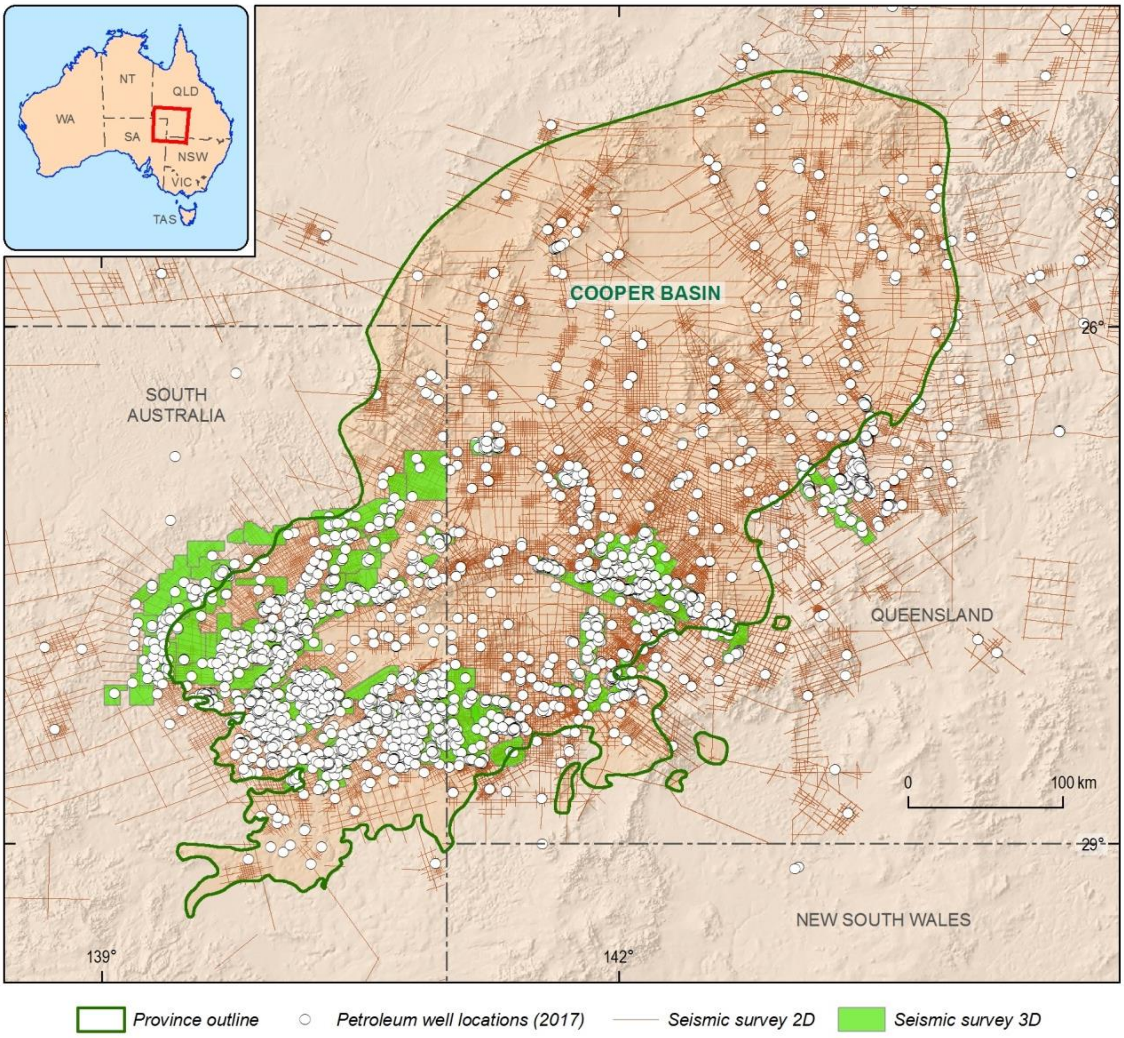

Figure C.33 Cooper Basin petroleum exploration wells current to 2017 and seismic data coverage (2D and 3D). Cooper Basin outline from Stewart et al. (2013). Petroleum well data from DNRME (2017a) and DPCSA (2017d). Seismic data coverage from DNRME (2017b-d) and DPCSA (2017a, e).

C.4.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Cooper Basin is summarised in Table C.25.

The Cooper Basin, in conjunction with the overlying Eromanga Basin, forms Australia's premier onshore conventional hydrocarbon producing province. It contains 256 gas fields and 166 oil fields currently in production, and is nationally significant in providing gas to the East Coast Gas Market (Hall et al., 2015). The Cooper Basin also hosts a range of unconventional play types within the Permian Gidgealpa Group, including basin-centred gas and tight gas accumulations and deep coal gas associated with the Patchawarra, Toolachee and Epsilon formations, and the Murteree and Roseneath shale gas plays (Goldstein et al., 2012). Data for the key unconventional hydrocarbon targets are summarised in Table C.26.

The principal shale gas play is the Roseneath-Epsilon-Murteree (REM) play comprising Permian Murteree and Roseneath shales separated by tight sands of the Epsilon Formation. These formations are generally restricted in extent to the southern part of the basin (Figure C.34; Hall et al., 2015).

Tight/basin-centred gas plays are present in multiple depocentres across the Cooper Basin (Figure C.34). The most extensive basin-centred/tight gas play lies within the Nappamerri Trough, where the Permian succession reaches over 1.3 km thick and comprises very thermally mature, gas-prone source rocks with interbedded sands (DPCSA, 2017). Thick siltstones of the Nappamerri Group act as a regional top seal for the pervasive gas accumulation, and the Roseneath and Murteree shales also assist with gas containment. Generation and expulsion of hydrocarbons from the Cooper Basin source rocks occurred in the mid-Cretaceous, but overpressure has been retained in the Nappamerri Trough.

The early Permian successions in the Patchawarra, Wooloo, Allunga and Windorah troughs also have the necessary elements for basin-centred and deep coal gas accumulations, including gas-prone coal beds, sufficient maturity for thermal gas generation, low-porosity and permeability reservoirs interbedded with the source rocks and gas shows (DPCSA, 2017).

Since Santos first produced shale gas from Moomba 191 in 2010, at least 40 wells have been drilled to test shale and tight plays across the Cooper Basin (Santos, 2012; DPCSA, 2017; DNRM, 2017). Although three unconventional wells have since sustained production (Moomba 191, 193H and 194; Santos, 2013a, b), no reserves of unconventional gas are currently reported for the basin.

In South Australia, there has been extensive active exploration for both shale, tight gas and deep coal by Beach Energy, Drillsearch, Santos and Senex (Goldstein et al., 2012; Beach, 2014; Core Energy, 2016). This activity has resulted in the following contingent resources:

- Senex booked 2C resources of 0.835 Tcf for tight sands associated with the Hornet gas field (PELs 115 and 516) on the southeastern flank of the Nappamerri Trough, 0.698 Tcf for tight sands associated with the Patchawarra Formation and the Murteree Shale at Sasanof (PEL 516) in the Allunga Trough (Senex, 2013).

- Beach booked 2C unconventional resources of 1.964 Tcf of gas for PRLs 33 to 49 (Beach Energy, 2014, 2015a).
- Santos booked a total 2C resource of 2345 PJ for the Cooper Basin (Santos, 2012)

Deep coal gas plays in the Patchawarra and Toolachee formations are being actively explored by Santos, Beach Energy and Senex, these are being included as part of the Cooper shale and tight gas assessment. Senex booked 2C resource of 0.421 Tcf for Patchawarra Formation coals around Paning-2 (PEL 90) in the Arrabury Trough (Senex, 2013).

In Queensland, ten wells have been drilled to examine the potential of the eastern Nappamerri Trough by Beach Energy and Drillsearch, which intersected up to 1.3 kilometres of gas-saturated Permian rocks (DNRM, 2017). Based on these drilling programs, the following resources have been booked for the Queensland side of the trough:

- Beach Energy booked 1.572 Tcf of 2C gas resources within ATP 855, which included both the Murteree and Roseneath shales, and the Epsilon, Toolachee, Daralingie and Patchawarra formations (Beach Energy, 2015c; Icon Energy, 2015).
- Drillsearch (owned by Beach Energy as of 2016) booked 2C gas resources of 0.771 Tcf for ATP 940 (Drillsearch, 2015).

It should be noted though that in 2016, Beach reduced the contingent resources associated with the Nappamerri Trough Natural Gas (NTNG) project from their annual reserves statement (Beach Energy, 2016). Beach stated that the results of stage 1 of the exploration program “demonstrated that the high cost of addressing fundamental technical issues means the NTNG project is unlikely to be developed commercially in the medium term”.

Further north in Queensland, three wells drilled by Santos and Real Energy have proven the existence of a basin-centred gas play within Patchawarra and Toolachee formations in the Windorah Trough (Queenscliff 1, Tamarama 1, Whanto South 1; Real Energy, 2014; Beach Energy, 2015a, b).

A range of basin scale prospective resource estimates for shale, tight and deep coal gas plays in the Cooper Basin have been published, as follows:

- The US Energy Information Administration (EIA) estimates the technically recoverable shale gas in the REM in Cooper Basin to be 92 Tcf (Table C.25; EIA, 2013). This included 89 Tcf in the Nappamerri Trough (prospective area - associated gas 625 mi^2, wet gas 555 mi^2, dry gas 3,525 mi^2) and 4 Tcf in the Patchawarra Trough (prospective area - associated gas 1,010 mi^2, wet gas 1,150 mi^2, dry gas 170 mi^2).
- AWT International have reported best estimates on recoverable shale gas in the REM to be 14 Tcf over a prospective area of 3,604 km^2 for wet gas and 35 Tcf over a prospective area of 9,106 km^2 for dry gas (Table C.25; AWT International, 2013).
- The United States Geological Survey published the following F50 (P50) estimate total undiscovered recoverable tight gas resources: 2.215 Tcf in the Patchawarra Trough, 14.547

Tcf in the Nappamerri Trough and 8.975 Tcf in the Queensland troughs (Table C.25; USGS, 2016).

- Core Energy (2016) reports deterministic sales of gas in place for Permian Coal at 113.77 Tcf.
- Most recently, Geoscience Australia published the following estimates of potentially recoverable in-place resources (5% recovery factor at P50):
  - 6.9 Tcf of shale gas in the Roseneath Shale (prospective area wet gas 3,834 km^2, dry gas 3,403 km^2) and Murteree Shale (prospective area wet gas 3,454 km^2, dry gas 3,291 km^2),
  - 50.9 Tcf of tight gas in the Patchawarra Formation (prospective area wet gas 14,426 km^2, dry gas 3,417 km^2), Epsilon Formation (prospective area wet gas 5,413 km^2, dry gas 3,401 km^2), Daralingie Formation (prospective area wet gas 4,691 km^2, dry gas 3,102 km^2) and Toolachee Formation (prospective area wet gas 15,070 km^2, dry gas 2,725 km^2) (Table C.25; AERA, 2018).

In the medium term (10 to 15 years) only a small amount of the gas-in-place could be extracted because of the early stage of exploration and the time needed to better define resources prior to production (AERA, 2018).

Both the results of industry activity and the large prospective resources estimates demonstrate that the Cooper Basin is highly prospective for both shale and tight gas. However the full extent of these resources are still poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty. Significant further drilling, testing and analyses are required to resolve the full shale and tight gas potential of the Cooper Basin. Further exploration and appraisal testing and success could result in a major new gas resource for eastern Australia.

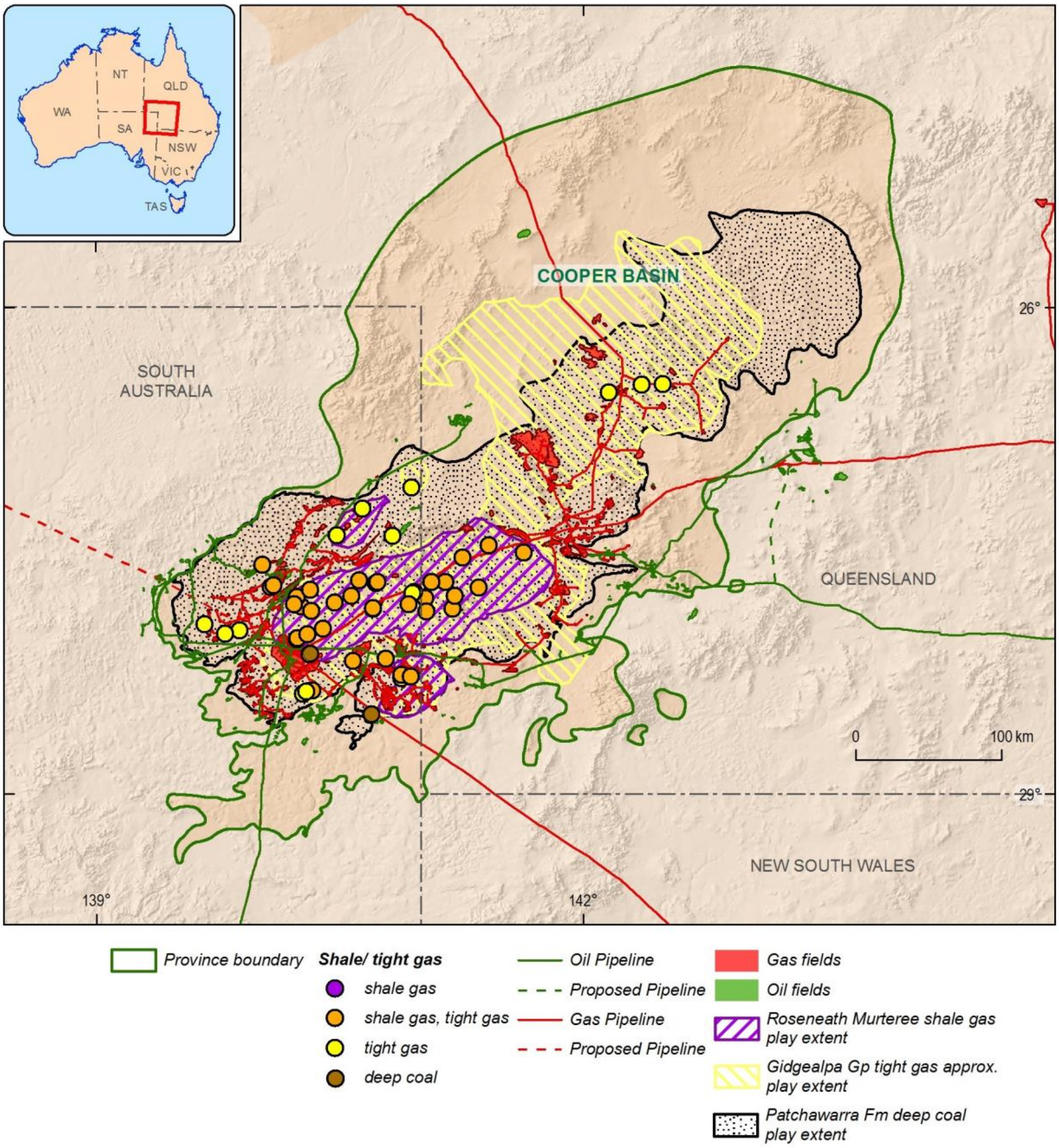

Figure C.34 Wells targeting shale or tight gas plays (source: Geoscience Australia), approximate shale and tight gas play extents (modified from USGS, 2016), conventional oil and gas fields, and pipelines. Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.26 Summary of shale, tight and deep coal gas plays (compiled from Hall et al., 2015, 2016a, b, UPR, 2015).

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity	Play type	Exploration status
Toolachee Formation	Late Permian	Fluvio-deltaic	1,500–2,800	0–280	Type II/III to Type III; coal, DOM	0–96	Immature – late gas	Tight, deep coal	Under assessment/ minor production
Daralingie Formation	Middle Permian	Fluvio-deltaic	1,600–3,200	0–130	Type II/III to Type III; coal, DOM	0–79	Immature – late gas/ over mature	Tight	Under assessment/ minor production
Roseneath Shale	Middle Permian	Lacustrine	1,600–3,400	0–240	Type III; DOM	0–22	Immature – over mature	Shale	Under assessment/ minor production
Epsilon Formation	Middle Permian	Prograding delta and lacustrine	1,700–3,600	0–195	Type II/III to Type III; coal, DOM	0–80	Immature – over mature	Tight, deep coal	Under assessment/ minor production
Murteree Shale	Early Permian	Deep, freshwater lacustrine	1,700–3,700	0–90	Type III; DOM	0–13	Immature – over mature	Shale	Under assessment/ minor production
Patchawarra Formation	Early Permian	Fluvio-lacustrine	1,400–3,800	0–680	Type II/III to Type III; coal, DOM	0–88	Immature – over mature	Tight, deep coal	Under assessment/ minor production

C.4.4 Gas market access and infrastructure

The Cooper Basin is a major supplier of gas to Australia’s East Coast Gas Market, with significant existing pipeline infrastructure connecting the basin to Adelaide, Sydney and Mount Isa (AER, 2017). The basin is moderately well serviced in terms of road and rail access.

Figure C.35 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.27.

Table C.27 Summary of market access and infrastructure. Pipeline information from AER (2017). Oil and gas infrastructure from GA (2015a), AER (2017) and Santos (2017). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	Currently supplies to the east coast gas market
Proximity to gas pipelines	• Moomba to Adelaide Pipeline - capacity 241 TJ/ Day (55 reverse) • Moomba to Sydney Pipeline - capacity 439 TJ/ Day (382 reverse) • Carpentaria Pipeline (Ballera to Mount Isa) – capacity 119 TJ/ Day
Gas processing facilities	Moomba (SA); Ballera (QLD)
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	<100 km
Road and rail access	Moderately well serviced
Approximate development timeframe	5–10 years

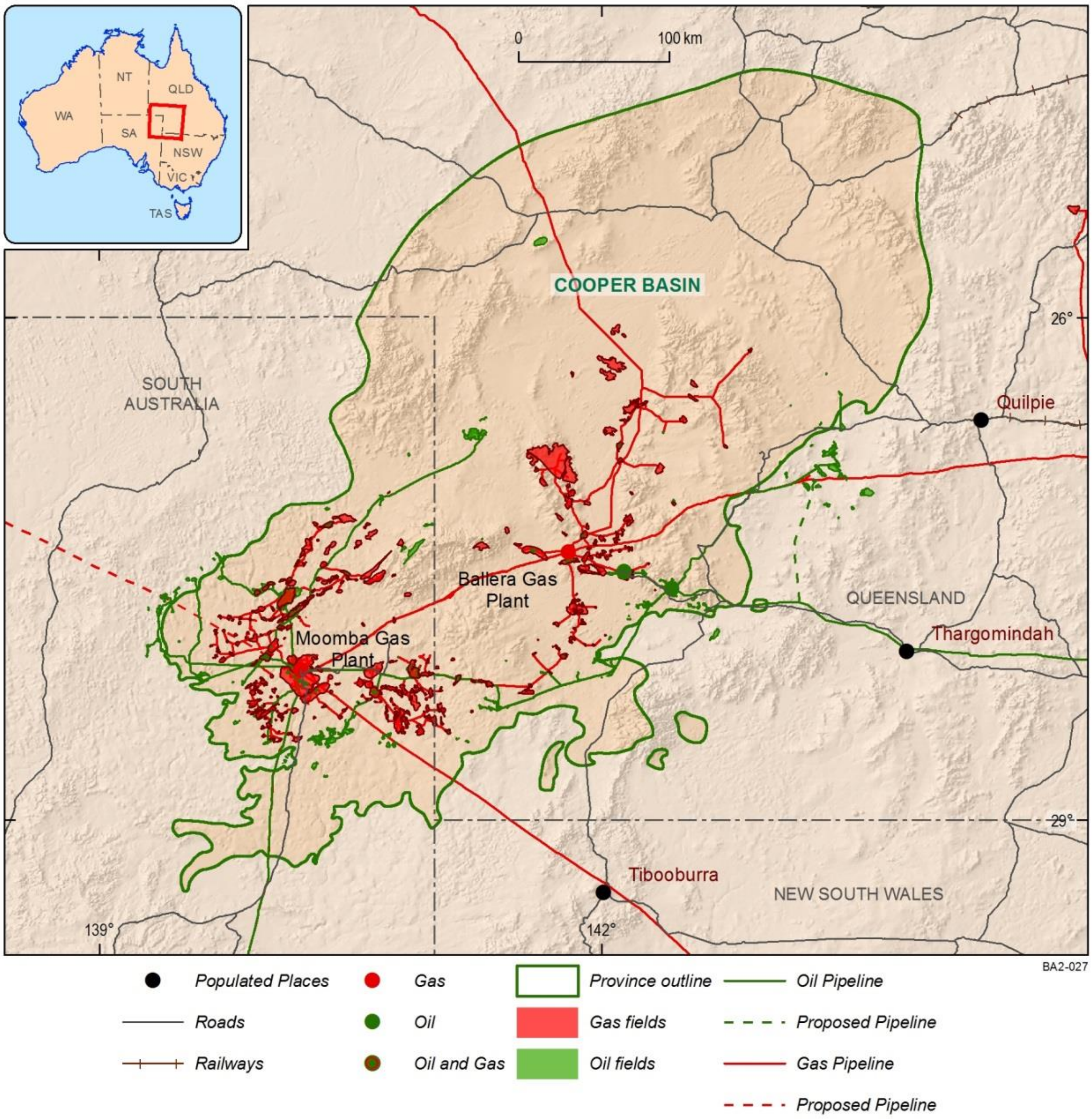

Figure C.35 Cooper Basin infrastructure, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

C.4.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia. There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland and South Australia. Further details regarding regulatory environment for each state are summarised below.

C.4.5.1 Queensland

The Queensland Government has no identified constraints to tight and shale gas resource drilling or production stimulation. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.4.5.2 South Australia

The South Australian Government is actively encouraging conventional and unconventional drilling and production stimulation via the Plan for Accelerating Exploration (PACE) Gas grant program, which aims to increase the supply of gas into South Australia's energy market to increase gas supplies and competition between gas suppliers (DPCSA, 2017c). However, in April 2018, the South Australian Government implemented the 10-year moratorium on hydraulic fracturing in the southeast of the state effectively stopping exploration for unconventional gas in the Otway Basin.

C.4.6 Hydrogeology and groundwater

As part of the Bioregional Assessment Programme into coal mining and coal-seam-gas developments, Smith et al., (2015) provided a review into the known hydrology and hydrogeology of the Cooper Basin region; the majority of information presented in this section is derived from this work. Substantial information about the overlying Great Artesian Basin (GAB) has been compiled in the Great Artesian Basin Water Resources Assessment (Ransley and Smerdon, 2012) and subsequent Hydrogeological Atlas of the Great Artesian Basin (Ransley et al., 2015). Information on groundwater within the Cooper Basin succession and the overlying aquifers in South Australia has been compiled by the state's Department for Water (SA Department for Water, 2011).

C.4.6.1 Groundwater systems

The Carboniferous–Triassic Cooper Basin is entirely overlain by the Jurassic–Cretaceous Eromanga Basin, and parts are in turn covered by Cenozoic sediments, primarily of the Lake Eyre Basin. The Cooper Basin succession generally comprises alternating sandstone and siltstone units that are considered as aquifers and aquitards (Table C.28), but have variable properties (SA Department for Water, 2011; Toupin et al., 1998; Smith et al., 2015).

The Eromanga Basin contains a series of stacked aquifers, separated by aquitards, although there is considerable variability in hydraulic properties due to changes of sedimentary facies, as well as disruptions to aquifer continuity due to faults (Figure C.36). The Cadna-owie Formation and Algebuckina Sandstone are the main artesian aquifers; which along with the underlying aquifers, are confined by the Rolling Downs Group. Subartesian bores and aquifers are also present in the Winton and Mackunda formations (Ransley and Smerdon, 2012; Ransley et al., 2015; SA Department for Water, 2011; Smith et al., 2015).

The Lake Eyre Basin (Paleocene to Quaternary) overlies the Eromanga Basin. The Lake Eyre Basin contains up to 400 m of Cenozoic sediments which include a number of aquifers and aquitards (SA Department for Water, 2011; Smith et al., 2015).

Table C.28 Classification of aquifers and aquitards within the Cooper Basin sequence (Smith et al., 2015).

	Unit	Hydrogeology (SA Department for Water, 2011)	Hydrostratigraphic Unit Description (Toupin et al., 1997)	Hydrogeological characteristics (Golder Associates, 2011)	Reservoir or seal (Radke, 2009)
Triassic	Cuddapan Formation	Aquifer	Not included	Not characterised	Reservoir
Permian	Tinchoo Formation	Aquifer	Confining bed	Confining beda	Reservoir
	Arrabury Formation	Major aquitard	Confining bed	Confining bed	Seal
	Toolachee Formation	Aquifer	Confining bed Sandstone aquifer	Aquifer	Reservoir
	Daralingie Formation	Aquifer and aquitard	Sandstone aquifer	Confining bed	Reservoir
	Roseneath Shale	Aquitard	Sandstone aquifer	Confining bed	Seal
	Epsilon Formation	Aquifer	Sandstone aquifer	Aquifer	Reservoir
	Murteree Shale	Aquitard	Confining bed	Confining bed	Seal
	Patchawarra Formation	Aquifer	Confining bed Sandstone aquifer	Aquifer	Reservoir
	Tirrawarra Sandstone	Aquifer	Sandstone aquifer	Aquifer	Reservoir
Carboniferous	Merrimelia Formation	Aquifer	Not included	Water bearing	Not Classified

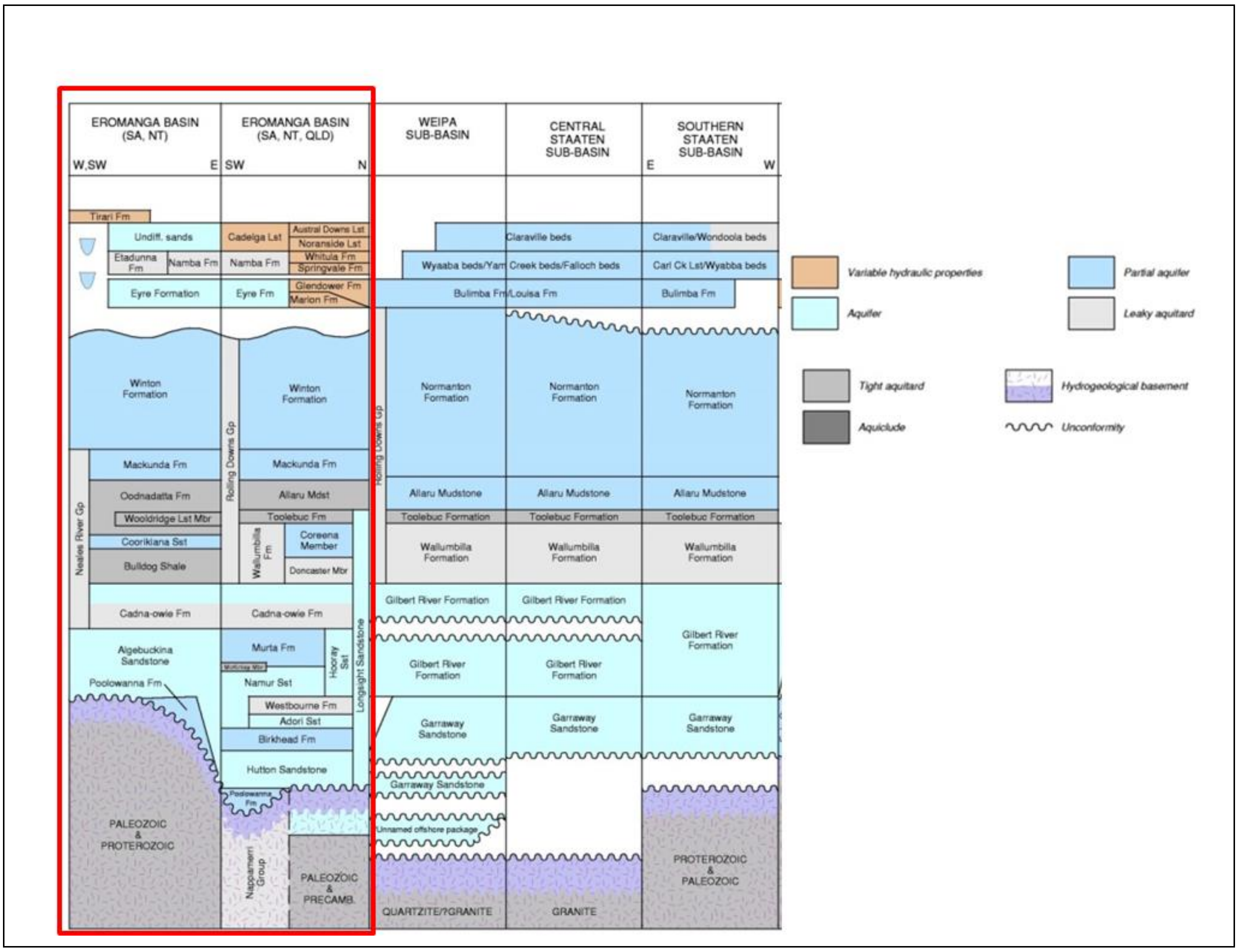

Figure C.36 Hydrostratigraphy of the Great Artesian Basin, highlighting the variation in aquifers and aquitards of the Eromanga Basin (in red box) as it overlies the Cooper Basin (adapted from Ransley et al., 2015).

C.4.6.2 Groundwater quality

Salinity in the Cooper Basin generally increases towards the centre of the basin and with formation age (Smith et al., 2015). The upper Nappamerri Group aquifers are usually somewhat fresher than underlying aquifer formations. Salinity levels as indicated by total dissolved solids (TDS) are presented in Table C.29. Several areas of lower salinity are found in the Patchawarra Formation where it directly underlies the Hutton Sandstone of the Eromanga Basin (Dubsky and McPhail, 2001; Smith et al., 2015).

In the Eromanga Basin, salinity levels increase towards the southwest, due to water-rock interactions and the mixing with deeper groundwater. Most aquifers in the Eromanga Basin have mean salinities of 2,600–3,800 mg/L TDS. The Jurassic–Lower Cretaceous aquifers are usually suitable for domestic, town and stock uses, but not irrigation due to high sodium and alkalinity levels. However, there is some variation within aquifers, where local salinity levels influence water use. Older water from the Namur and Adori sandstones is often better in quality than the shallower Cadna-owie Formation. The Coorikiana Sandstone (in the Rolling Downs Group) forms a high-salinity, low-yield discrete aquifer and is generally not exploited (see Hydrostratigraphy in Figure C.36). Groundwater from Winton and Mackunda aquifers has high salinity, but is generally acceptable for stock water (Radke et al., 2000; Ransley and Smerdon, 2012; SA Department for Water, 2011; Smith et al., 2015).

Mapping in the "Hydrogeological Atlas of the Great Artesian Basin" suggests that TDS ranges for the Cadna-owie Formation/Hooray Sandstone (1080–9000 mg/L), Adori Formation and equivalents (1,060–2,600 mg/L) and Hutton Sandstone and equivalents (1,060–3,800 mg/L) (Ransley et al., 2015).

The Eyre Formation aquifer within the Lake Eyre Basin is brackish to saline (3,000–12,000 mg/L TDS), but useable for stock purposes. The water quality of other Cenozoic aquifers is highly variable, with fresh groundwater in shallow dunes overlying more saline water (SA Department for Water, 2011; Smith et al., 2012).

Table C.29 Salinity in aquifers of the Cooper Basin region (Smith et al., 2015). NA: data not available.

Formation	Total dissolved solids (mg/L)		
	Mean	Min	Max
Murta	3,775	2,549	4,971
Namur-McKinlay	2,766	1,810	4,766
Westbourne-Adori	3,497	NA	NA
Birkhead-Hutton	2,630	959	5,729
Poolowanna	4,344	3,085	9,245
Nappamerri	3,763	2,660	4,950
Toolachee-Daralingie	5,714	1,463	12,232
Epsilon	5,473	2,202	9,722
Patchawarra	9,514	2,050	17,420
Tirrawarra-Merrimelia	9,444	5,530	11,656
Basement	4,312	NA	NA

C.4.6.3 Groundwater flow

The water table usually lies within the hydraulically continuous Winton-Mackunda aquifer (see Figure C.37). However, in places, the water table lies above this level within the Lake Eyre Basin sediments (Ransley et al., 2015; Ransley and Smerdon, 2012; Smith et al., 2015). Regional groundwater flow in the Eromanga Basin is from the recharge areas (mostly in the Great Dividing Range) to discharge zones focused in the western Eromanga Basin. Mound springs to the west of Lake Eyre are within the discharge areas, including lakes Frome, Callabonna, Blanche and Gregory.

There is generally a southwesterly flow direction, mirrored by potentiometric surfaces for all individual aquifers (Figure C.37); flow rates are less than 0.3 m/yr in areas of the Eromanga Basin where the aquifers are deeply buried. Additionally, there is some vertical flow across leaky aquitards (Ransley and Smerdon, 2012; Love et al., 2013; Smith et al., 2015; Ransley et al., 2015).

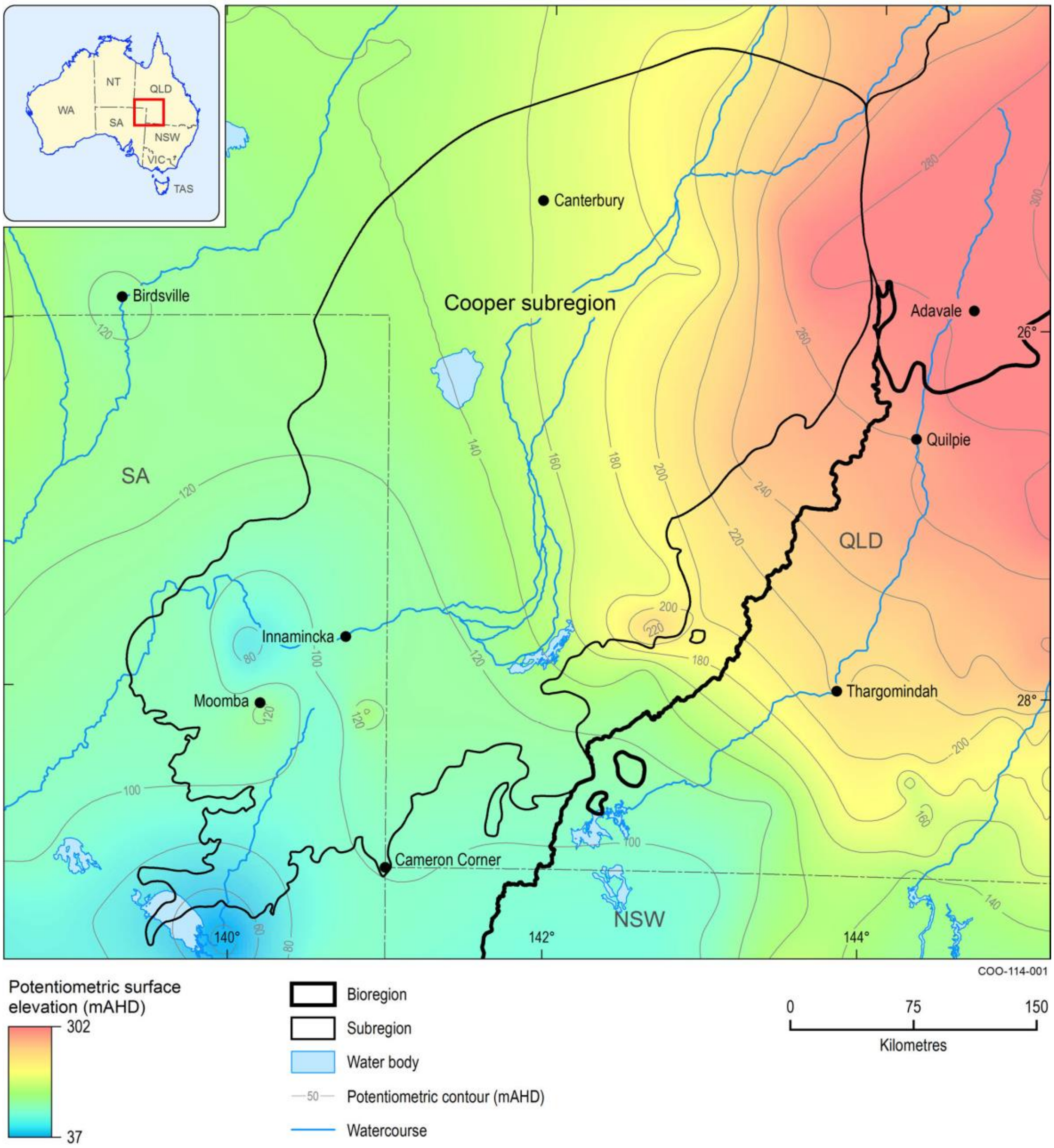

Figure C.37 Potentiometric surface of the Cadna-owie/Algebuckina aquifer around the Cooper Basin (labelled as Cooper subregion), calculated from a density-corrected perspective (Smith et al., 2015).

C.4.6.4 Groundwater planning and use

Currently groundwater use within the Cooper Basin region is from overlying aquifers of the GAB and Lake Eyre Basin sequence. Water is produced from formations of the Cooper Basin (“produced formation water”) as a co-product of oil and gas operations. South Australia provides a license of

60 ML/day for this produced formation water (SAALNRMB, 2009; Smith et al. 2015; SA Department for Water, 2011).

No monitoring bores screen groundwater within the Cooper Basin succession, but several bores screen aquifers of the Eromanga Basin succession as part of monitoring of the GAB. In Queensland, a license is required for artesian water, so the majority of bores are licensed. A Water Resource Plan for the GAB exists (Water Plan (Great Artesian Basin) 2006) (Queensland Government, 2006), and this considers connected sub-artesian water as well as artesian water. For South Australia, a Water Allocation Plan is in place for the Far North Prescribed Wells Area (SAALNRMB, 2009), and this limits drawdown in the vicinity of springs. There is an estimated average of 0.2 L/second extraction per bore from GAB bores in the region (Queensland Government, 2006; SAALNRMB, 2009; Smith et al., 2015; Welsh et al., 2012).

Table C.30 presents information from the NGIS (BoM, 2016) and shows summary information of registered bores in the basin.

Table C.30 Summary of groundwater bores and water use.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	4066 (0.03)	
Purposes of registered bores (Top 5, number)	Unknown	3303
	Exploration	595
	Industrial	93
	Stock	61
	Domestic Household	21
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 35.7 Median: 1840 90th Percentile: 3024	

C.4.7 Surface water systems and hydrology

As part of the Bioregional Assessment Programme into coal mining and coal-seam gas developments, Smith et al., (2015) provided a review into the known hydrology and hydrogeology of the Cooper Basin region; the majority of information in this section is derived from this work. The Lake Eyre Basin Rivers Assessment (Cockayne et al., 2013) and the Hydrology of the Lake Eyre Basin Project (McMahon et al., 2005) inform substantial components of this understanding into surface-water hydrology.

C.4.7.1 Surface water systems

The Cooper Basin is overlain by two river catchments, both within the Lake Eyre drainage division: the Cooper Creek–Bulloo River basin and the Diamantina–Georgina river basin. The Cooper Creek–Bulloo River basin is the main catchment (91% by land area over the Cooper Basin), with the Cooper Creek, Thomson River, Barcoo River and Bulloo River being the main streams. The major surface water catchments are presented in Figure B.14. The Cooper Creek area has an extensive floodplain, which can exceed 60 km in width with anastomosing and anabranching channels. The only significant watercourse in the Diamantina–Georgina river basin found within the Cooper Basin region is Farrars Creek, which is a tributary to Diamantina River; anastomosing channels are typical of the landscape. Both catchments are typical arid zone catchments (McMahon et al., 2005; Cockayne et al., 2013; Knighton and Nanson, 2001; BoM, 2014; Smith et al., 2015).

C.4.7.2 Surface water quality

There is poor data availability for water quality in the region. Typically, however, EC levels are around 200 µS/cm during times of baseflow and drop to around 100 µS/cm during high flow. Turbidity is typically high and variable (Cockayne et al., 2013; Smith et al., 2015).

C.4.7.3 Surface water flow

Streamflow is highly variable in this arid environment, where most rivers are ephemeral or intermittent, with little groundwater contribution to streamflow. The low topographic gradient leads to slow flow, so large floods can take 16 days to pass the floodplain (Smith et al., 2015). Runoff in the Cooper Creek catchment is derived from the headwater streams (Thomson and Barcoo rivers), with very high transmission loses that often exceed 80%. Consequently, downstream flows can be less than those upstream despite the increased catchment area, due to evaporation, bank storage, and losing stream reaches.

A number of stream gauges are sited on the Cooper Creek and a few of its tributaries (Table C.31); elsewhere, stream gauge information is limited. Streamflow varies greatly between years and months from almost no flow to significant flooding (McMahon et al., 2005; Knighton and Nanson 2001; Cockayne et al., 2013; Smith et al., 2015).

Table C.31 Stream gauges in and around the Cooper Basin region, identifying the data record period and mean annual flows measured (compiled in Smith et al., 2015).

Gauge number	Stream gauge name	Catchment area (km^2)	Mean annual flow (GL/y)	Drainage basin	Data period
003101A	Cooper Creek at Currareva	150,220	3642	Cooper	1966–1988
003103A	Cooper Creek at Nappa Merrie	237,000	1607	Cooper	1949–present
AW003501	Cooper Creek at Callamurra	230,000	1430	Cooper	1973–2004
003202A	Thomson River at Longreach	57,590	1228	Cooper	1969–present
003203A	Thomson River at Stonehenge	87,810	2361	Cooper	1966–present
003204A	Cornish Creek at Bowen Downs	22,830	338	Cooper	1968–present
003205A	Darr River at Darr	2,700	49	Cooper	1969–present
003301A,B	Barcoo River at Retreat	51,663	1193	Cooper	1999–present
003302A	Alice River at Barcaldine	7,918	55	Cooper	1968–present
003303A	Barcoo River at Blackall	8,782	102	Cooper	1969–present
002101A,B	Diamantina River at Birdsville	115,200	1261	Diamantina	1949–1988
002104A	Diamantina River at Diamantina Lakes	54,130	1835	Diamantina	1966–present
002105A	Mills Creek at Oondooroo	2,642	0.3	Diamantina	2007–present

C.4.7.4 Surface water dams, planning and use

The Lake Eyre catchments are all unregulated: there are no major dams or weirs, diversions for irrigation or public water storages in the Cooper Creek catchment, nor any large storages on the Diamantina River. In the Water Plan (Cooper Creek) 2011, the Queensland Government has 2,000 ML of unallocated water (200 ML for general reserve, 1,300 ML for strategic reserve and 500 ML for the town and community reserve) in the Cooper Creek catchment (Queensland Government, 2011). The Water Resource (Georgina and Diamantina) Plan 2004 (Queensland Government, 2004) allocates 1,000 ML as general reserve in the Lower Diamantina management area, and another 1,500 ML is available across the whole Diamantina-Georgina catchment area for projects of state significance. However, there is negligible use of surface water in the region, as most users are reliant on groundwater for a dependable water supply (McMahon et al., 2005; Smith et al., 2015).

C.4.8 Groundwater–surface water interactions

There is limited information available on the groundwater–surface water interactions above the Cooper Basin. Some flowing artesian springs occur near to the Cooper Basin extent, and these are usually associated with structural features such as faults and folds. Water-table mapping suggests there is a potential for surface water and groundwater to interact and support Groundwater Dependant Ecosystems (discussed further in the section below). Large flooding events do occur, yet contribute limited recharge as evaporation rates are high. Groundwater discharge allows ephemeral flows to support some groundwater-dependent aquatic ecosystems hosted within the wetlands (e.g. the Ramsar-listed Coongie Lakes) and watercourses (Ransley and Smerdon, 2012; Love et al., 2013; Smith et al., 2015).

C.4.9 Environmental assets

Within the Cooper Basin there are 16,186 km^2 of Listed Nationally Important Wetlands, 13,800 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential) and the Ramsar-listed Coongie Lakes wetland, and a total of 15,440 km^2 of protected areas (such as national parks) are listed (Table C.32).

Table C.32 Summary of environmental assets.

Environmental Assets		
Ramsar Wetlands	Coongie Lakes	
Nationally Important Wetlands Top 5 by area (area km^2)	Coongie Lakes	11,864
	Cooper Creek Overflow Swamps - Windorah	1,219
	Cooper Creek Swamps - Nappa Merrie	1,038
	Lake Yamma Yamma	845
	Cooper Creek - Wilson River Junction	624
	TOTAL WETLAND AREA	16,186
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	Regional Reserve	13,808
	National Park	1,472
	Nature Refuge	160
	—	0
	—	0
	TOTAL PROTECTED AREA	15,440
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	13,800	

C.4.10 Social considerations

The Cooper Basin occupies a remote location with a low and sparse population. A high proportion of the population is itinerant, working in the oil and gas industry. Other industries include pastoral and tourism.

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in Table C.33.

Table C.33 Summary of population, land use and aboriginal protected area.

GENERAL CHARACTERISTICS		
Population	393	
Major population centres (two)	Jundah, Windorah	
Land use types Top 5 by area (area km^2)	Grazing native vegetation	103,277
	Nature Conservation	10,820
	Mining and waste	7,950
	Water	4,882
	Urban intensive uses	22
Aboriginal Protected Area (CAPAD, 2016) and Native title (area km^2)	61,556	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

AERA (Australian Energy Resources Assessment) (2018) Australian Energy Resources Assessment interim report, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.ga.gov.au/aera>.

Alexander EM, Gravestock DI, Cubitt C and A Chaney A (1998) Chapter 6: Lithostratigraphy and environments of deposition. In: Gravestock DI, Hibburt JE and Drexel JF (eds), The Petroleum Geology of South Australia, Volume 4: Cooper Basin. South Australia Department of Primary Industries and Resources, Adelaide, Report Book, 1998/9, 69–115. Viewed 22/01/2018, <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGSA004.pdf>.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

Beach Energy (2014) FY14 Full year review results roadshow. Viewed 16/01/2018, , <www.asx.com.au/asxpdf/20140828/pdf/42rtkq464xqggw.pdf>.

Beach Energy (2015) Annual report. Viewed 16/01/2018, <www.beachenergy.com.au/irm/PDF/4440_0/2015BeachEnergyLtdAnnualReport>.

Beach Energy (2015b) ASX/Media Release – Monthly drilling report November 2015. Viewed 16/01/2018, <http://www.beachenergy.com.au/irm/PDF/4564_0/MonthlyDrillingReportNovember2015>.

Beach Energy (2015c) ASX/Media Release – Upgrade of Nappamerri Trough Natural Gas Contingent Resources. Viewed 16/01/2018, <http://www.beachenergy.com.au/IRM/Company/ShowPage.aspx/PDFs/3985-10000000/NTNGContingentResources>.

Beach Energy (2016) ASX/Media Release – 1P, 2P and 3P reserves and 2C contingent resources as at 30 June 2016. Viewed 16/01/2018, <http://www.beachenergy.com.au/irm/PDF/6210_0/ReservesandContingentResourcesasat30June2016>.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

CAPAD (2016) Collaborative Australian Protected Area Database 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Carr LK, Korsch RJ, Palu TJ and Reese B (2016) Onshore Basin Inventory: the McArthur, South Nicholson, Georgina, Wiso, Amadeus, Warburton, Cooper and Galilee basins, central Australia. Record 2016/04. Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/Record.2016.004>.

Cockayne B, Schmarr D, Duguid A and Mathwin R (2013) “Lake Eyre Basin Rivers Assessment 2012 monitoring report”. A report to the Department of Sustainability, Environment, Water, Population and Communities (SEWPaC), Canberra.

Cook AG, Bryan SE and Draper JJ (2013) Post-orogenic Mesozoic basins and magmatism. In: Jell PA (ed.), Geology of Queensland. Geological Survey of Queensland, Brisbane, 515–575.

Cook AG and Jell PA (2013) Paleogene and Neogene. In: Jell PA (ed.), Geology of Queensland. Geological Survey of Queensland, Brisbane, 577–649.

Core (2014) Gas reserves and resources, eastern and southeastern Australia. Core Energy Group report to the Australian Energy Market Operator. Viewed 09/08/2017, <https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2015/Core--Gas-Reserves-and-Resources.pdf>.

Core Energy Group (2016) Cooper-Eromanga Basin Outlook | 2035. Viewed 10/04/18, http://petroleum.statedevelopment.sa.gov.au/prospectivity/cooper_basin/core_energy_cooper-eromanga_basin_outlook_2035.

DNRM (Department of Natural Resources and Mines) (2017) Queensland's unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017a) 3D Seismic Survey Areas lines. Viewed 23/07/2017, <https://map.sarig.sa.gov.au/>.

DPCSA (Department of the Premier and Cabinet, South Australia) (2017b) Cooper Basin gas well information for unconventional resource plays. Viewed 16/01/2018, <http://petroleum.statedevelopment.sa.gov.au/prospectivity/resource_plays/cooper_basin_gas_well_information_for_unconventional_reservoir_plays>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017c) PACE Gas. Viewed 16/01/2018, <http://petroleum.statedevelopment.sa.gov.au/latest_updates/pace_gas>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017d) Petroleum well. Viewed 16/01/2018, <https://map.sarig.sa.gov.au/>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017e) Seismic lines. Viewed 16/01/2018, <https://map.sarig.sa.gov.au/>.

Draper JJ (ed.) (2002) Geology of the Cooper and Eromanga Basins, Queensland. Queensland Government, Natural Resources and Mines, Queensland Mineral and Energy Review Series.

Drillsearch (2015) ASX/Media Release – 2015 reserves and contingent resource statement. Viewed 16/01/2018, <http://www.asx.com.au/asxpdf/20150826/pdf/430t3gtkqdgjjt.pdf>.

Dubsky M and McPhail A (2001) Environmental Impact Research Report (EIR) SA Cooper Basin Well Operations Statement of Environmental Objectives (SEO) Water Pressure and Salinity Module Report. SA Chamber of Mines and Energy.

EIA (Energy Information Administration) (2013) Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. United States Energy Information Administration, 730 p. Viewed 16/01/2018, <https://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf>.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Gatehouse CG (1972) Formations of the Gidgealpa Group in the Cooper Basin. Australasian Oil and Gas Review, 18(2), 10–15.

Goldstein B, Menpes S, Hill A, Wickham A, Alexander E, Jarosz M, Pepicelli D, Malavazos M, Staritski K, Taliangis P, Coda J, Hill D and Webb M (2012) Roadmap for Unconventional Gas Projects in South Australia. Department for Manufacturing, Innovation, Trade, Resources and Energy, 267p. Viewed 18/01/2018, <https://statedevelopment.sa.gov.au/resourcesUNPUBLISHED/unconventional-gas-projects>.

Gravestock DI, Hibburt JE and Drexel JF (eds.) (1998) Petroleum geology of South Australia, Volume 4: Cooper Basin. South Australia Department of Industries and Resources, Report Book, 1998/9. Viewed 17/01/2018, <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGSA004.pdf>.

Gravestock DI and Jensen-Schmidt B (1998) Chapter 5: structural setting. In: Gravestock DI, Hibburt JE and Drexel JF (eds.), The Petroleum Geology of South Australia, Volume 4: Cooper Basin. South Australia Department of Primary Industries and Resources, Adelaide, Report Book, 1998/9, 47–67. Viewed 22/01/2018, <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGSA004.pdf>.

Gray ARG and McKellar JL (2002) Cooper Basin stratigraphy. In: Draper JJ (ed.), Geology of the Cooper and Eromanga basins, Queensland. Queensland Department of Natural Resources and Mines, Queensland Minerals and Energy Review Series, 9–26.

Hall LS, Hill A, Troup A, Korsch R, Radke B, Nicoll RS, Palu T, Wang L and Stacey A (2015) Cooper Basin Architecture and Lithofacies: Regional Hydrocarbon Prospectivity of the Cooper Basin, Part 1. Record 2015/31. Geoscience Australia, Canberra. Viewed 11/08/2017, <http://dx.doi.org/10.11636/Record.2015.031>.

Hall LS, Boreham CJ, Edwards DS, Palu TJ, Buckler T, Hill A, and Troup A (2016a) Cooper Basin Source Rock Geochemistry: Regional Hydrocarbon Prospectivity of the Cooper Basin, Part 2. Record 2016/06. Geoscience Australia, Canberra. Viewed 11/08/2017, <http://dx.doi.org/10.11636/Record.2016.006>.

Hall LS, Palu TJ, Murray AP, Boreham CJ, Edwards DS, Hill AJ and Troup A (2016b) Petroleum Systems Modelling of Cooper Basin: Regional Hydrocarbon Prospectivity of the Cooper Basin, Part 3. Record 2016/29. Geoscience Australia, Canberra. Viewed 11/08/2017, <http://dx.doi.org/10.11636/Record.2016.029>.

Hill AJ and Gravestock DI (1995) The Cooper Basin. In: Drexel JF and Preiss WV (eds.), The geology of South Australia. Volume 2: The Phanerozoic. South Australian Geological Survey Bulletin, 54, 78–87.

Icon Energy (2015) ASX Media release – 2015 AGM address and presentation. Viewed 22/01/2018, <www.asx.com.au/asxpdf/20151124/pdf/4337wzg3zqbcnx.pdf>.

Jell PA (ed.) (2013) Geology of Queensland. Geological Survey of Queensland, Brisbane.

Knighton AD and Nanson GC (2001) An event-based approach to the hydrology of arid zone rivers in the Channel Country of Australia. Journal of Hydrology 254, 102–123.

Love AJ, Wohling D, Fulton S, Rousseau-Gueutin P and De Ritter S (eds) (2013) “Allocating Water and Maintaining Springs in the Great Artesian Basin, Volume II: Groundwater Recharge, Hydrodynamics and Hydrochemistry of the Western Great Artesian Basin”. National Water Commission, Canberra.

McKellar JL (2013) The Cooper Basin. In: Jell, PA (ed.), Geology of Queensland. Geological Survey of Queensland, Brisbane, 204–212.

McMahon TA, Murphy R, Little P, Costelloe JF, Peel MC, Chiew FHS, Hays S, Nathan R and Kandel DD (2005) “Hydrology of Lake Eyre Basin, Final report”. A report to the Australian Government Natural Heritage Trust, Sinclair Knight Merz (SKM) Pty Ltd, Melbourne.

Nakanishi T and Lang SC (2001) The search for stratigraphic traps goes on – visualisation of fluival-lacustrine successions in the Moorari 3D survey, Cooper–Eromanga Basin. The APPEA Journal, 41, 115–137.

Price PL (1997) Permian to Jurassic palynostratigraphic nomenclature of the Bowen and Surat Basins. In: Green PM (ed.), The Surat and Bowen Basins, south-east Queensland. Queensland Minerals and Energy Review Series, 137–178.

Queensland Government (2004) "Water Plan (Condamine and Balonne) 2004", legislation under the Water Act 2000 (Qld), Current as at 2 September 2017. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/inforce/current/sl-2004-0151>.

Queensland Government (2006) “Water Plan (Great Artesian Basin) 2006”, legislation under the Water Act 2000 (Qld), current as at 3 July 2017. Viewed 04/08/2017, https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf>.

Queensland Government (2011) “Water Plan (Cooper Creek) 2011”, legislation under the Water Act 2000 (Qld), current as at 6 December 2016. Viewed 04/08/2017, <https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReCCPl11.pdf>.

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 22/01/2018, <https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells>.

Radke B (2009) Hydrocarbon and Geothermal Prospectivity of Sedimentary Basins in Central Australia Warburton, Cooper, Pedirka, Galilee, Simpson and Eromanga Basins. Record 2009/25, Geoscience Australia, Canberra.

Radke B, Ferguson J, Cresswell R, Ransley T and Habermehl M (2000) Hydrochemistry and implied hydrodynamics of the Cadna-owie – Hooray Aquifer, Great Artesian Basin. Bureau of Rural Sciences, Canberra.

Ransley TR, Radke BM, Feitz AJ, Kellett JR, Owens R, Bell J, Stewart G and Carey H (2015) Hydrogeological Atlas of the Great Artesian Basin, Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/9781925124668>.

Ransley TR and Smerdon BD (eds) (2012) Hydrostratigraphy, hydrogeology and system conceptualisation of the Great Artesian Basin. A technical report to the Australian Government from the CSIRO Great Artesian Basin Water Resource Assessment. CSIRO Water for a Healthy Country Flagship, Australia, 285 pp.

Real Energy (2014) ASX/Media Release – Real Energy updates gas resource estimates. Viewed 22/01/2018, <http://www.realenergy.com.au/news-reports/announcements.html>.

SAALNRMB (South Australian Arid Lands Natural Resources Management Board) (2009) Water Allocation Plan for the Far North Prescribed Wells Area.

SA Department for Water (2011) Far North PWA Groundwater Level and Salinity Status Report 2011. South Australian Department for Water, Adelaide, SA.

SA Department of Environment Water and Natural Resources (2015) Malkumba-Coongie Lakes National Park, in National Parks, South Australia. Viewed 09/09/2017, <https://www.environment.sa.gov.au/parks/Find_a_Park/Browse_by_region/flinders-ranges-outback/malkumba-coongie-lakes-national-park>.

Santos (2012) Cooper Basin unconventional gas opportunities and commercialisation. Viewed 16/01/2018, <https://www.santos.com/media-centre/announcements/cooper-basin-unconventional-gas-opportunities-and-commercialisation/>.

Santos (2013a) ASX/Media Release – Further shale gas success at Moomba-194 in the Cooper Basin. Viewed 16/01/2018, <www.asx.com.au/asxpdf/20131219/pdf/42lqm1v2lzkh1w.pdf>.

Santos (2013b) Moomba 191 and beyond. Viewed 16/01/2018, <https://www.santos.com/media/2132/130828_moomba_191_and_beyond.pdf>.

Santos (2017) Cooper Basin. Viewed 16/01/2018, <https://www.santos.com/what-we-do/activities/south-australia/cooper-basin/>.

Senex (2013) AWS Announcement – Major contingent gas resource upgrade to 5.5 Tcf. Viewed 16/01/2018, <http://www.senexenergy.com.au/investor-centre/files/major-contingent-gas-resource-upgrade-to-5-5-Tcf/>.

Smith M, Karim F, Sparrow A, Cassel R and Hall L (2015) Context statement for the Cooper subregion. Product 1.1 for the Cooper subregion from the Lake Eyre Basin Bioregional Assessment. Bioregional Assessment Programme, Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia. Viewed 16/01/2018, <http://data.bioregionalassessments.gov.au/doc/BA-LEB-COO-110-ContextStatement-20150903.pdf>.

Strike Energy (2015) ASX Announcement – DUG Australia conference presentation – July 2015. Viewed 16/01/2018, <http://www.strikeenergy.com.au/wp-content/uploads/2015/07/20150729-DUG-July-2015-Presentation.pdf>.

Toupin D, Eadington PJ, Person M, Morin P, Wieck J and Warner D (1997) Petroleum hydrogeology of the Cooper and Eromanga Basins, Australia: some insights from mathematical modeling and fluid inclusion data. AAPG Bulletin 81(4), 577–603.

UPR (Upstream Petroleum Resources Working Group) (2015) Coal seam, shale and tight gas in Australia: resources assessment and operation overview 2015, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/UPR%20Unconventional%20Resources%20Report%202015%20-%20Final_0.pdf>.

USGS (2016) Assessment of continuous oil and gas resources of the Cooper Basin Australia, 2016. Viewed 16/01/2018, <https://pubs.usgs.gov/fs/2016/3050/fs20163050.pdf>

Welsh WD, Moore C, Turnadge C, Smith AJ and Barr TM (2012) Modelling of climate and groundwater development. A technical report to the Australian Government from the CSIRO Great Artesian Basin Water Resource Assessment. CSIRO Water for a Healthy Country Flagship, Australia.

C.5 Georgina Basin

Table C.34 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	Northern Territory, Queensland
Area	354,744 km2
Max. basin depth/ sediment thickness	Up to 4,000 m
Age range	Neoproterozoic to Devonian
Depositional setting	Marine (siliciclastics, carbonates, evaporates); fluvial; glacial.
Regional structure	Southern fault-controlled depocentres and central–northern platform; extensional faults inverted as thrust and strike-slip faults during Alice Springs Orogeny
Overlying basins	Carpentaria Basin in NW; Eromanga Basin in SE
Underlying basins	McArthur Basin, South Nicholson Basin, Isa Superbasin
EXPLORATION STATUS	
Seismic lines	11,767 line km, 2D seismic
Number of petroleum wells	>70
Exploration status – conventional	Under-explored
Exploration status – shale/ tight gas	Under-explored
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Larapintine Supersystem; Boreham and Ambrose, 2007)
Prospectivity	Moderate
Conventional discoveries	No commercial accumulations; one significant technical discovery at Ethabuka 1 (1974) - dry gas recovery from Coolibah Formation (Munson, 2014)
Hydrocarbon production – total to date	None to date (DNRM, 2016a; AERA, 2018)
2P Reserves	No reserves reported (DNRM, 2016b; AERA, 2018)
Remaining resources (reserves + contingent resources)	Not reported (AERA, 2018)
Undiscovered resource estimates	Conventional unknown; see prospective resources for shale/ tight gas below
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Shale gas, tight gas
No. of wells targeting shale/tight gas plays	>22

Production – shale/ tight gas	None
2P Reserves – shale/ tight gas	None reported
Remaining resources (reserves + contingent resources) – shale/ tight gas	None reported
Undiscovered resource estimates – shale/ tight gas	• Technically recoverable shale gas resources for the lower Arthur Creek Formation of 8 Tcf in the Dulcie Syncline (prospective area wet gas 2,260 mi^2, 1,950 mi^2 dry gas) and 5 Tcf in the Toko Syncline (prospective area associated gas 3,220 mi^2, wet gas 2,010 mi^2, dry gas 790 mi^2) (EIA, 2013) • Best estimate of recoverable shale gas resource of 50 Tcf for the Arthur Creek Formation over a prospective area of 14,433 km^2 (Table A.3; AWT International, 2013) • Mean total prospective technically recoverable gas resource of 15 Tcf in the upper Arthur Creek Shale (prospective area 4,531 km^2) and 18 Tcf in the lower Arthur Creek Shale (prospective area 4,068 km^2)
Hydrocarbon shows, tests – shale/ tight gas	Ethabuka 1 (1974): dry gas recovery, Coolibah Formation; Gaudi 1 gas shows, lower Arthur Creek Formation

C.5.1 Basin Geology

The Georgina Basin is a Neoproterozoic–early Paleozoic epicratonic basin located in western Queensland and eastern Northern Territory (Figure C.38; Table C.34). The basin is the erosional remnant of what was a much larger Proterozoic and early Paleozoic basin deposited in a sea that extended over much of eastern Australia. During the Neoproterozoic (1000–542 Ma), the Georgina Basin was part of the Centralian Superbasin, which encompassed the Amadeus, Ngalia, Officer and Savory basins (Walter et al., 1995; Munson et al., 2013). The Petermann Orogeny in the late Neoproterozoic isolated the Georgina Basin from the Amadeus Basin. Early middle Cambrian seaways connected the Georgina Basin with the Wiso Basin in the west and very probably with the Daly Basin in the northwest, beneath Mesozoic cover (Jell, 2013).

The basin consists of two distinct domains: depocentres in the southern part of the basin (southern Georgina Basin), including the Dulcie and Toko synclines, and a central-northern platform (Munson, 2014). In the south, the succession is Neoproterozoic to Devonian, with more than 1,500 m of Neoproterozoic glacial and marine sedimentary rocks preserved in fault-controlled depocentres along the southern margin. These are overlain by a 2200 m thick Cambrian to Devonian succession containing carbonate, clastic and evaporitic sedimentary rocks deposited in deep, shallow and restricted marine, inter-tidal, and supratidal environments (Figure C.39; Munson, 2014).

The eastern portion of the basin overlies the Paleoproterozoic–Mesoproterozoic Isa Superbasin, and the northern margin overlies the Paleoproterozoic McArthur Basin and the Mesoproterozoic South Nicholson Basin, where the Neoproterozoic to Cambrian succession only reaches a maximum thickness of 300 m (Munson, 2014). The Georgina Basin is overlain by Cretaceous sandstones of the Carpentaria Basin in the northwest, and Jurassic–Cretaceous sedimentary rocks of the Eromanga Basin along the southeastern margin.

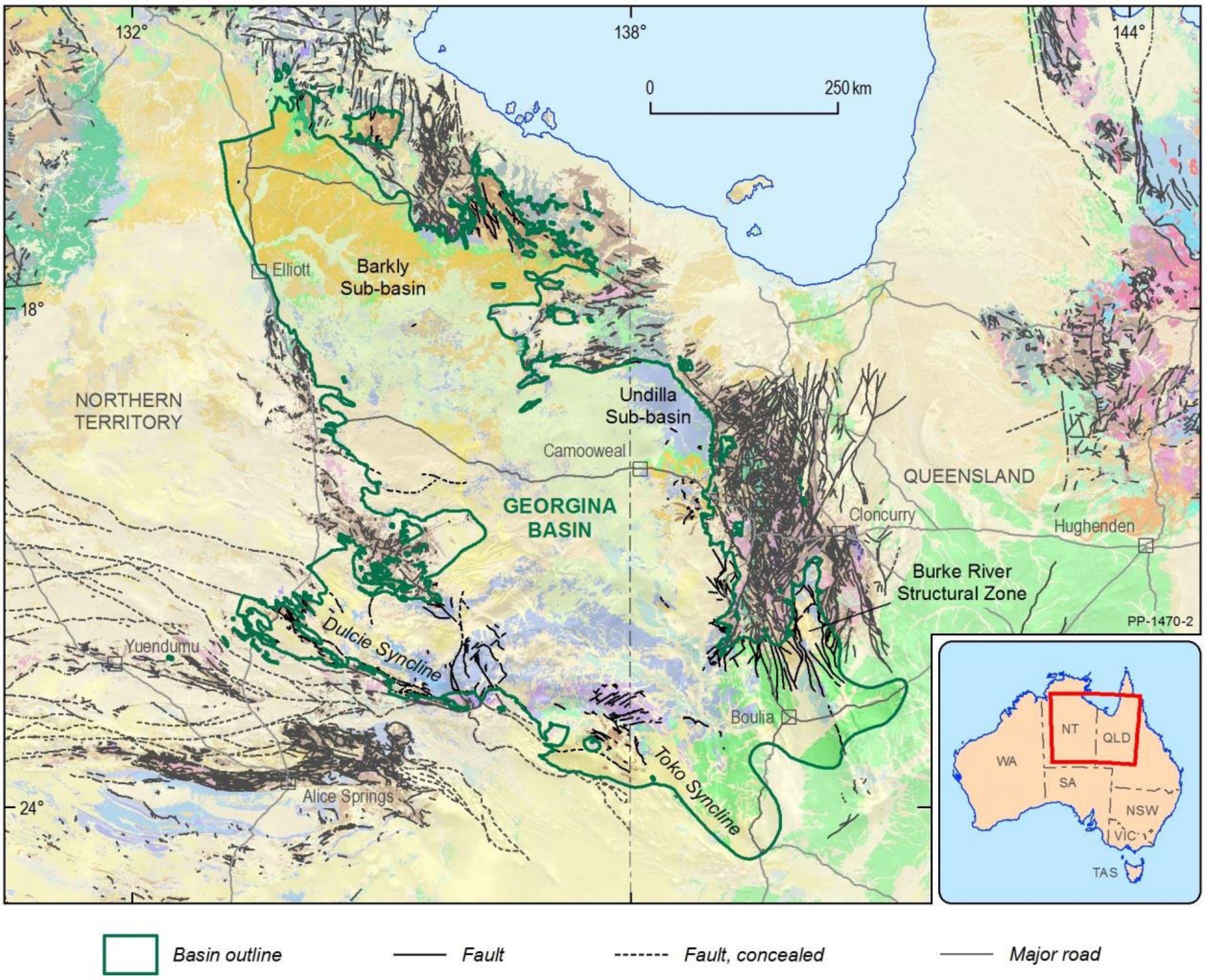

Figure C.38 Location of the Georgina Basin on a base map of surface geology from Carr et al. (2016). The surface geology is from the 1:1,000,000 scale geology map of Australia (Raymond, 2009), and the outline of the Georgina Basin is from Stewart et al. (2013).

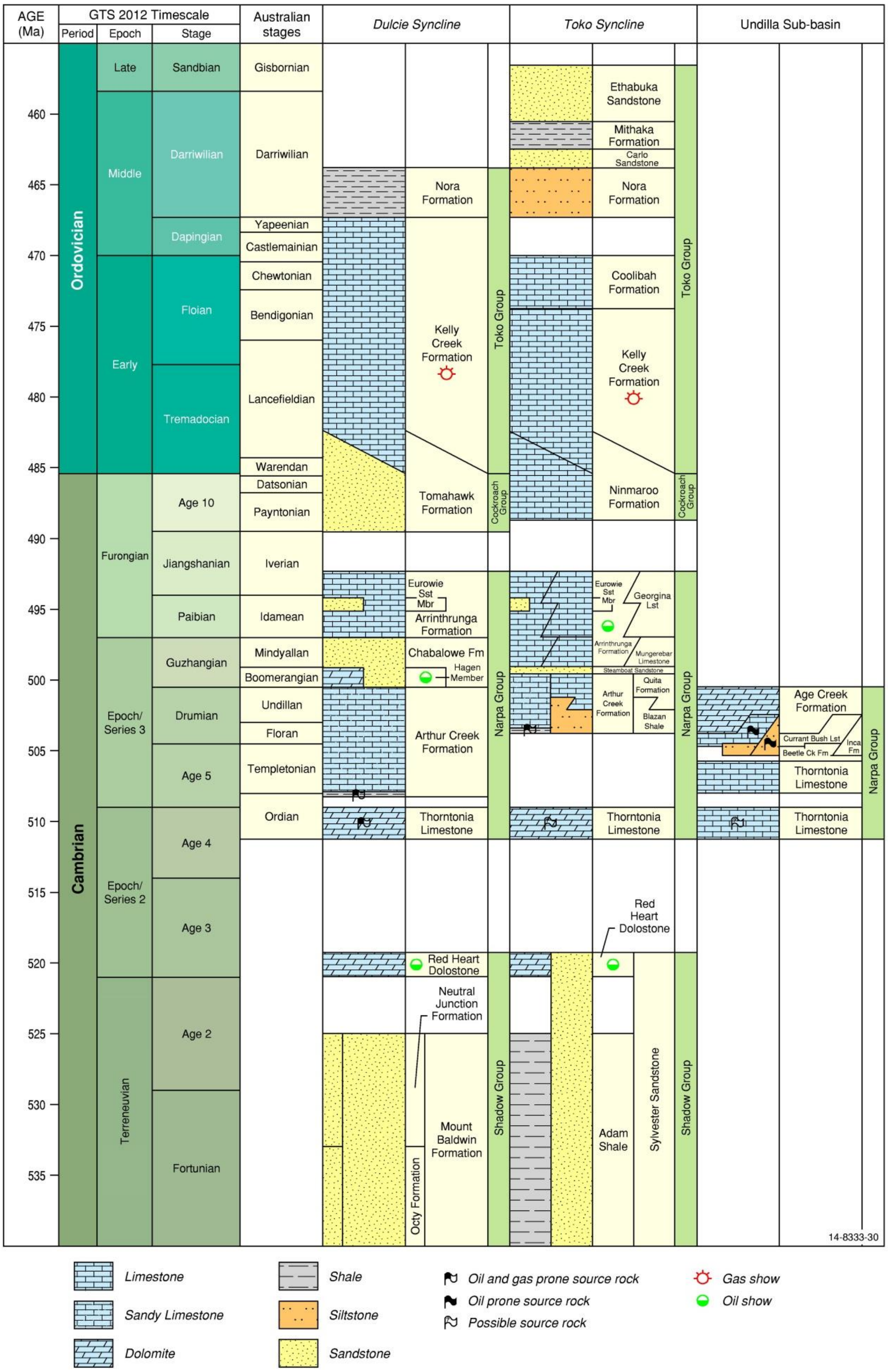

Figure C.39 Stratigraphy of the Georgina Basin from Carr et al. (2016). Early Paleozoic stratigraphy showing the locations of key source rocks and hydrocarbon shows in the Cambrian to Ordovician part of the basin. Note that

Devonian units in the Dulcie Syncline (Dulcie Sandstone) and Toko Syncline (Cravens Peak beds) have been omitted from this figure.

C.5.2 Petroleum data coverage

Despite recent interest in the Georgina Basin, it remains underexplored. Over 70 wells (petroleum and stratigraphic) have been drilled, most of which are located in the southern part of the basin and the Burke River Structural Zone in the east (Figure C.40; Carr et al., 2016; DNRME, 2017a; NTGS, 2017a). In contrast, very little exploration has occurred in the central and northern portions of the basin, with only one petroleum well drilled in the Undilla Sub-basin and two wells in the Barkly Sub-basin (Munson, 2014). A higher well density in far northeast of the basin reflects exploration targeting the underlying Beetaloo Sub-basin succession of the McArthur Basin.

A limited amount of 2D seismic data has been acquired in the Georgina Basin (Figure C.40; DNRME, 2017b-d; NTGS, 2017b), with most lines predating the 1990s. One of the most significant recent surveys was conducted in 2013 by Central Petroleum Ltd, in a joint venture with Total, who acquired approximately 970 km of seismic data across the Toko Syncline (Willink and Allison, 2015; Central Petroleum, 2017). Several deep seismic reflection lines have been collected by Geoscience Australia and partners, providing insights into the large-scale basin architecture (e.g. Carr and Korsch, 2011; Carr et al., 2016).

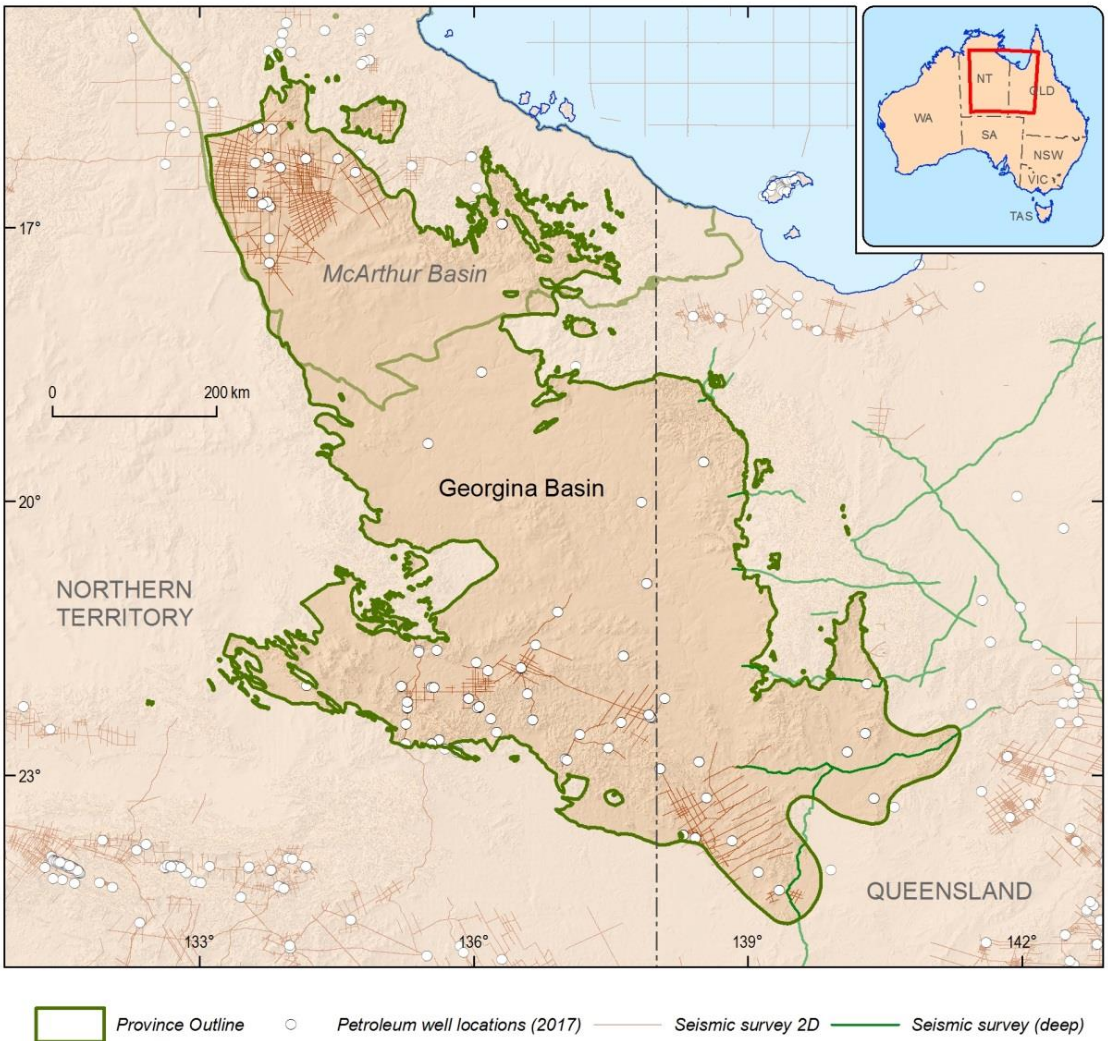

Figure C.40 Georgina Basin petroleum exploration wells, stratigraphic drill holes. Georgina Basin outline from Stewart et al. (2013). Well locations from DNMRE (2017a) and NTGS (2017a). Seismic data from DNMRE (2017b-d) and NTGS (2017b).

C.5.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Georgina Basin is summarised in Table C.34.

Recent exploration in the Georgina Basin has mainly focused on unconventional hydrocarbons (Bennett et al., 2010; Ryder Scott Company Petroleum Consultants, 2010; DSWPET, 2011; Vu et al., 2011; Ambrose et al., 2012; Boult and Bennett, 2012; Willink and Allison, 2015). Over 22 wells have been drilled across a broad area of the southern Georgina Basin, in both the Northern Territory and Queensland, targeting unconventional shale oil, shale gas and basin-centred gas plays (Figure C.39; Munson, 2014).

The Arthur Creek Formation is considered to contain the most prospective unconventional gas targets in the Georgina Basin. These include fractured shale and other tight reservoirs (e.g. fractured/vuggy silty dolostone) of the upper Arthur Creek Formation, and fractured silty shale of the lower Arthur Creek Formation (Munson, 2014). Additional targets include shale and tight gas plays in the Thorntonia Limestone and the Arrinthrunga Formation, along with more speculative plays in the Georgina Limestone, Beetle Creek Formation and Inca Shale (Table C.35; Figure C.41; Draper, 2007; DNRM, 2017; Willink and Allison, 2015).

In the Northern Territory, three horizontal wells were drilled by PetroFrontier in 2011 in a joint venture with Baraka Energy and Resources Ltd, targeting the base of the Arthur Creek Formation and Thorntonia Limestone. Baldwin 2H and MacIntyre 2H were located in the Dulcie Syncline and Owen 3H in the northern Toko Syncline close to the QLD-NT border ST1 (PetroFrontier, 2011; Baraka, 2012). Both MacIntyre 2H and Owen 3H were successfully stimulated and completed, although no hydrocarbons were recovered (Baraka, 2012).

In 2014, five wells were drilled across the southeastern part of the basin in the Northern Territory (OzAlpha 1, OzBeta 1, OzGamma 1, OzDelta 1, OzEpsilon 1), as part of joint venture between Statoil and PetroFrontier to explore for shale oil. The wells primarily targeted the lower Arthur Creek Formation and Thorntonia Limestone. Hydrocarbons were encountered, but testing of two wells did not result in any hydrocarbon flow to the surface. Following these results, Statoil withdrew from the licence area (Statoil, 2014).

In the Toko Syncline in Queensland, Central Petroleum continue to investigate shale gas and tight gas targets, in addition to potential conventional gas accumulations (Willink and Allison, 2015; Central Petroleum, 2012, 2017; DNRM, 2017). In 2014, two wells (Whiteley 1; Gaudi 1) were drilled to evaluate the lower Arthur Creek Formation and the Thorntonia Limestone (Central Petroleum, 2017; DNRM, 2017). Only Gaudi 1 reached its intended target, recording good gas shows in the lower Arthur Creek Formation.

Several regional scale prospective resource estimates have been published for shale gas plays in the Georgina, as described below:

- An assessment of the unconventional hydrocarbon plays for the eastern Toko Syncline of the Georgina Basin estimated a mean total prospective technically recoverable gas resource of 15 Tcf in the upper Arthur Creek Shale (prospective area 4,531 km^2) and 18 Tcf in the lower Arthur Creek Shale (prospective area 4,068 km^2) (Table C.34; DSWPET, 2011).
- The US Energy Information Administration (EIA) reported technically recoverable shale gas resources for the lower Arthur Creek Formation of 8 Tcf in the Dulcie Syncline (prospective area wet gas 2,260 mi^2, 1,950 mi^2 dry gas) and 5 Tcf in the Toko Syncline (prospective area associated gas 3,220 mi^2, wet gas 2,010 mi^2, dry gas 790 mi^2) (Table C.34; EIA, 2013).
- AWT International reported a best estimate of recoverable shale gas resource of 50 Tcf for the Arthur Creek Formation over a prospective area of 14,433 km^2 (Table C.34; AWT International, 2013).

Although initial industry activity results indicate that the Georgina Basin is potentially prospective for shale and tight gas, both the Northern Territory and Queensland portions of the basin are still in an early phase of exploration. Drilling results to date have met with mixed success, and uncertainties due to lack of geological knowledge are considerable. As a result, the full extent of the shale and tight gas resources in the basin remain poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty. Significant further seismic data acquisition, drilling and testing are required to improve our understanding of the shale and tight gas resource potential of this basin.

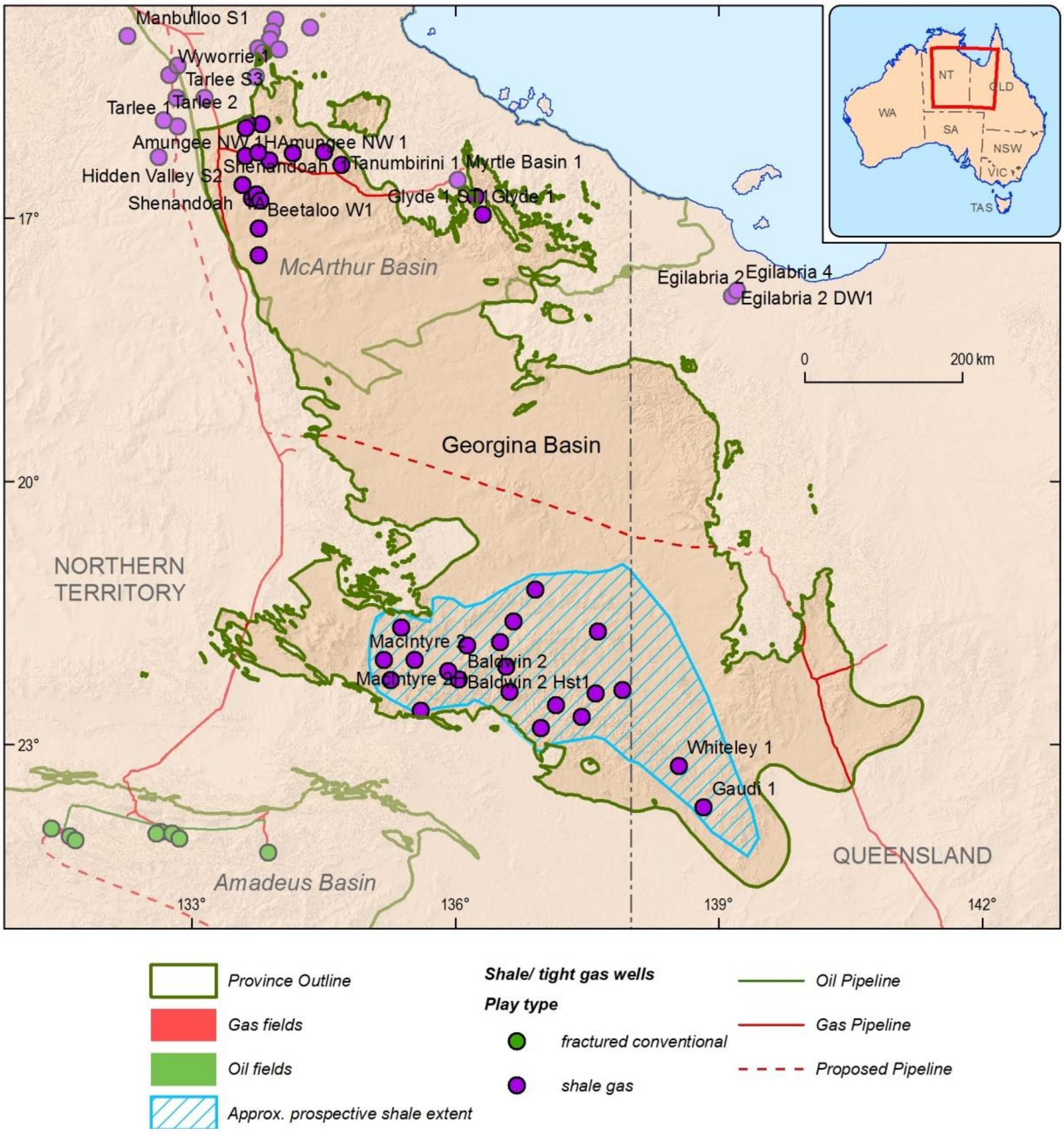

Figure C.41 Wells targeting shale or tight gas plays compiled from various industry and government sources. Well locations from DNMR (2017a) and NTGS, 2017). Approximate area within which key prospective shales are likely to be present is based on Munson (2014); Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) and DMRN (2017b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.35 Summary of shale and tight gas plays (compiled from Draper, 2007; Dunster et al., 2007; Munson, 2014; UPR, 2015; DNRM, 2017).

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity	Play type	Exploration status
Arrinthrunga Formation (Dulcie and west Toko synclines)	late Cambrian	shallow marine	0–830	Max 975 m	Type II; type II-III	Av 1.8 %; 0–11%	Immature-gas mature	Shale gas, tight gas	Unknown
Georgina Limestone (east Toko Syncline)	late Cambrian	deep water	0–2,500	~400 m	Unknown	Unknown	Unknown	?Shale gas, tight gas	Unknown
Arthur Creek Formation (Dulcie and west Toko synclines)	middle Cambrian	dysoxic to anoxic, deeper marine	0–1,550	Max >438m	Type II; type II-III	Av 1.6 %; 0–14%	Immature-gas mature	Shale gas, tight gas	Preliminary exploration (e.g. Petrofrontier, 2011; Central Petroleum, 2017)
Inca Shale (Burke River Structural Belt)	middle Cambrian	marine	0–3,220	3–150 m	Unknown	Unknown	Unknown	?Shale gas, tight gas	Unknown
Beetle Creek Formation (Burke River Structural Belt)	middle Cambrian	marine	0–1,020	75–90 m	Unknown	Unknown	Unknown	?Shale gas, tight gas	Unknown
Thorntonia Limestone / Hay River Formation	middle Cambrian	peritidal to marine,	0–3,200	23 m to >400 m	Type II; type II-III	Av 1.5%; 0– 8.3%	Immature-gas mature	Shale gas, tight gas	Preliminary exploration (e.g. Petrofrontier, 2011; Central Petroleum, 2017)

C.5.4 Gas market access and infrastructure

The Georgina Basin is located between the East Coast Gas Market and the Northern Territory Gas Market, but does not currently supply gas to either. Existing pipeline infrastructure could connect the basin to Adelaide, Sydney and Mount Isa (AER, 2017). The basin is poorly to moderately well serviced in terms of road and rail access, depending on location.

Figure C.42 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.36.

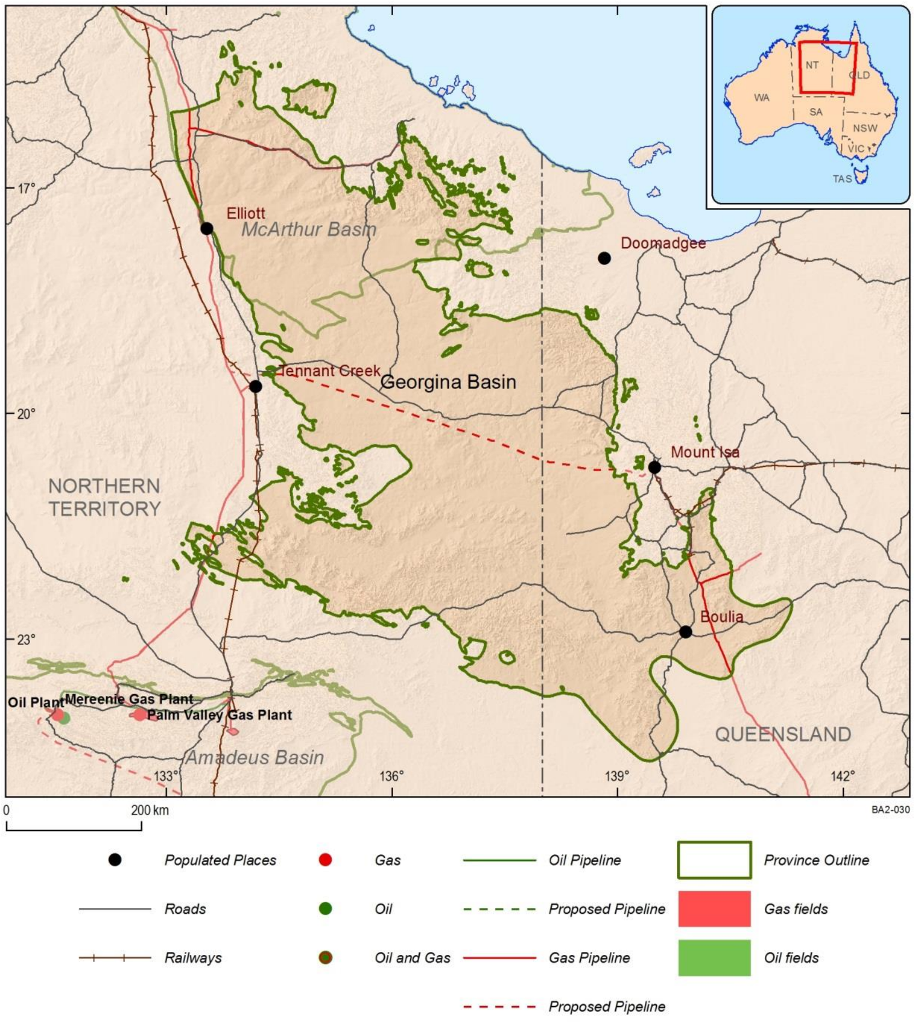

Figure C.42 Georgina Basin infrastructure, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.36 Summary of market access and infrastructure. Pipeline information from AER (2017) and Jemena (2017). Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	Located between the East Coast Gas Market and Northern Territory Gas Market; no current supply to either
Gas pipelines	• Amadeus Gas Pipeline (Amadeus Basin to Darwin) – capacity 120 TJ/day • Carpentaria Pipeline (Ballera to Mount Isa) – capacity 119 TJ/ Day • Northern Gas Pipeline (under construction – due for completion end of 2018)
Gas processing facilities	None
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	200–400 km
Road and rail access	Poorly to moderately well serviced
Approximate development timeframe	8 to >10 years

C.5.5 *Regulatory environment impacting shale and tight gas exploration*

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia.

There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland. In 2016, the Northern Territory Government implemented a moratorium on unconventional onshore gas activities in the territory, while an inquiry was undertaken and pending the Government's decision on the recommendations of the inquiry; the final report of the inquiry was released in March 2018 (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). Details of the moratorium and regulatory restrictions are described below.

C.5.5.1 Northern Territory

In April 2018, the Northern Territory Government accepted all 135 recommendations of the inquiry and lifted the moratorium on hydraulic fracturing over 51% of the Territory. An implementation plan to be released in July 2018 will clearly show how the recommendations will be implemented.

C.5.5.2 Queensland

The Queensland Government has no identified constraints to tight and shale gas resource drilling or production stimulation. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.5.6 Hydrogeology and groundwater

C.5.6.1 Groundwater systems

The primary water-bearing units identified in the Georgina Basin are the Paleozoic carbonate formations that host fractured or fissured, extensive and highly productive aquifers (Jacobson and Lau, 1987). Less significant sources are found in fractured rock aquifers and porous clastic rock aquifers. Sporadic incidences of Cenozoic age sediments have also shown to provide regionally significant groundwater. Selected stratigraphy is presented in Figure C.39. A more comprehensive stratigraphy can be found in Smith et al. (2013).

C.5.6.1.1 Carbonate Aquifers (middle–upper Cambrian to Ordovician)

Carbonate aquifers are the most important source of groundwater in the Georgina Basin and they are widespread. Of the carbonate aquifers, the Gum Ridge and Anthony Lagoon Formation and their equivalents have been the most extensively developed (Randal, 1978).

The Gum Ridge/Hay River Formations (part of the Narpa Group) consists of fossiliferous siltstone, chert, silicified limestone, and some sandstones including leached calcareous sandstones. The depth to groundwater varies significantly throughout the basin, ranging from 15 m to 168 m (Verma and Jolly, 1992). The reported thickness of the unit varies between 350 m (Verma and Jolly, 1992) and 3–25 m at the margins of the basin (Smith, 1972). Aquifer yields have been reported from 0.5–5 L/s, with higher yields possible when cavities are present in this carbonate sequence (Verma and Jolly, 1992).

The overlying Anthony Lagoon Formation is a carbonate-siliciclastic unit incorporating dolomitic siltstone, dolomitic sandstone-siltstone interbeds, quartz sandstone and a variety of carbonate rock types (Munro, 2012). The thickness of the unit and its equivalents is up to 395 m, while in outcrop, thicknesses of 15m have been reported (Verma and Jolly, 1992). The depth to the water table typically ranges from approximately 35 m to 145 m below ground level.

C.5.6.1.2 Fractured Rock Aquifers (middle Cambrian)

Fractured rock aquifers are present in the southeast region of the basin and consist of clastic and silicified clastic rocks of middle Cambrian age. The fractured rock aquifers do not have the same solution cavities as the carbonates and this is reflected by lower groundwater yields and water strike success rates. Of the fractured rock aquifers, the Beetle Creek Formation has been most extensively drilled. The groundwater regimes range from shallow to deep, with average aquifer intersection of 111 m below ground level (Randal, 1978), and typical yield of around 1.5 L/s when groundwater is found.

C.5.6.1.3 Porous Rock Aquifers (middle Cambrian to Ordovician)

Low-yielding porous rock aquifers have been intersected across the basin. Formations include the Middle Cambrian Steamboat Sandstone, the Lower Ordovician Kelly Formation, the Cambrian–Ordovician Tomahawk Beds, the Lower Ordovician Swift Formation and the Middle Ordovician Nora and Upper Ordovician Carlo Formation. Typical depth to these aquifers is between 35 m and 186 m below ground level, with a groundwater yield of typically 1.5 L/s (Randal, 1978).

C.5.6.1.4 Cenozoic Aquifers

The Cenozoic units contain useful supplies of groundwater, but the quality, in terms of salinity (particularly from carbonate rocks) is typically not as good as underlying formations. Cenozoic aquifers include porous rock aquifers of coarse gravel, sandy gravels and soft sandstone (such as the Marion Formation) and carbonate aquifers (such as the Austral Downs Limestone and Noranside Limestone). Typical depth of aquifer ranges from 8 to 16 m below ground level with a thickness of around 30–40 m. Yields of around 1–2 L/s have been reported (Randal, 1978).

In the southwest, significant groundwater is present in the Cenozoic aquifers of the Western Davenport and Ti-Tree aquifers. Aquifer thickness in the Ti-Tree Basin reaches up to 80 m with yields between 5 and 15 L/s (DNREAS, 2009).

C.5.6.1.5 Eromanga Basin

The Jurassic to middle Cretaceous Eromanga Basin overlies the southeastern portion of the Georgina Basin and hosts the Great Artesian Basin (GAB), a complex and widespread series of aquifer and aquitard formations. Of note is the Early Cretaceous Cadna-owie aquifer and equivalents, which represents one of the most widespread aquifers. Although the formation as a whole is generally a poor aquifer, commonly there is a thin upper sandstone member that is an excellent aquifer and is widely utilised by agriculture and industry. The Cadna-owie aquifer dips towards the east where it's around 200–400 m deep, the thickness of the aquifer ranges from 0–100 m (Ransley et al., 2015).

C.5.6.2 Groundwater quality

Whilst groundwater quality shows considerable variation across the Georgina Basin, some broad spatial patterns are evident.

Groundwater salinity levels are generally low in the middle Cambrian limestones and are generally lower than the non-carbonate aquifers, with average Total Dissolved Solids (TDS) concentrations ranging from 390–962 mg/L (Smith, 1972). Salinity within the Gum Ridge Formation is typically around 500 mg/L TDS, with higher concentrations found around the contact with the Anthony Lagoon Formation.

Salinity within the Anthony Lagoon Formation has shown significant variation, ranging from low (<500 mg/L) around Lake Tarrabool, where recharge is thought to occur, to high (>5000 mg/L) in areas of former evaporate beds (Verma and Jolly, 1992).

Cenozoic aquifers of the Ti-Tree and Western Davenport region typically show groundwater of sufficient quality for irrigation and stock purposes.

The major aquifers of the GAB in this region are typically between 500–1,200 mg/L TDS.

C.5.6.3 Groundwater flow

Groundwater flow directions are variable and are geographically and formation dependant. Groundwater flows of the Gum Ridge Formation are typically east to northeasterly and the

Anthony Lagoon Formation northwesterly (Verma and Jolly, 1992). Figure C.43 shows the generalised regional groundwater flow in the Cambrian limestones in the northern portion of the basin.

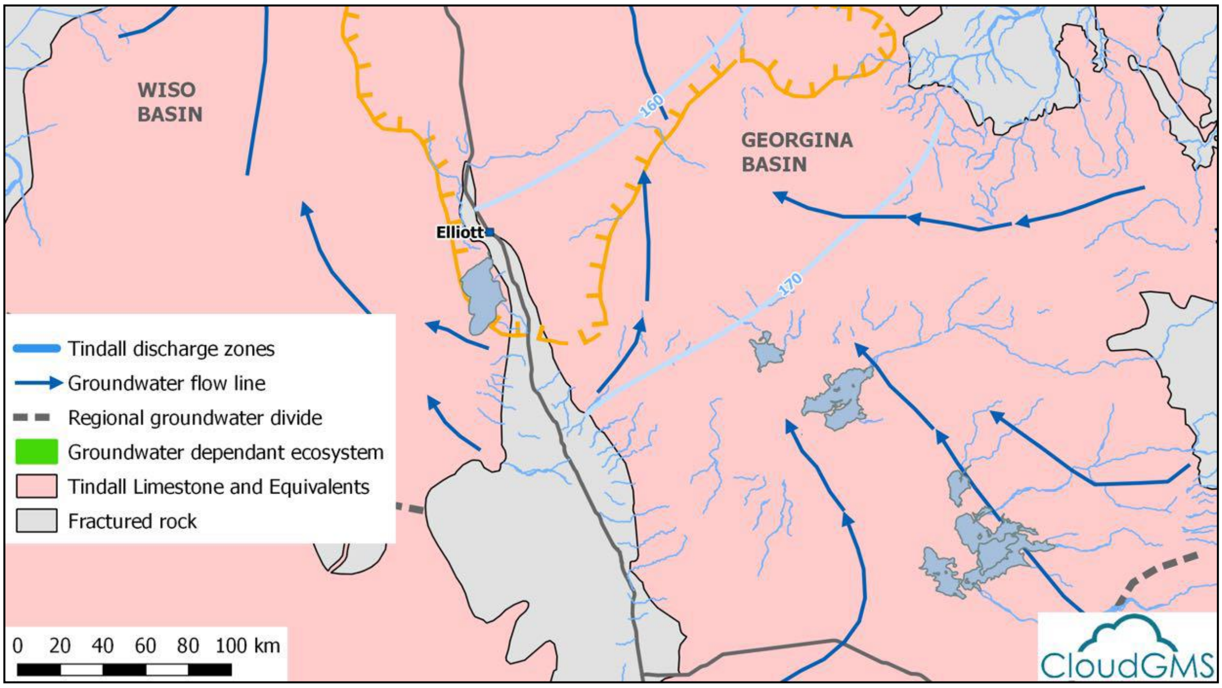

Figure C.43 Regional groundwater flow in the Cambrian limestones of the northern portion of the Georgina Basin (adapted from Knapton 2009).

In the southeastern Georgina Basin groundwater flow is typically in a west to northwesterly direction (Figure C.44). Towards the centre of the basin groundwater flow is southwards beneath, but typically not into, the GAB. There is also some evidence for groundwater flowing downwards from the GAB into the Georgina Basin.

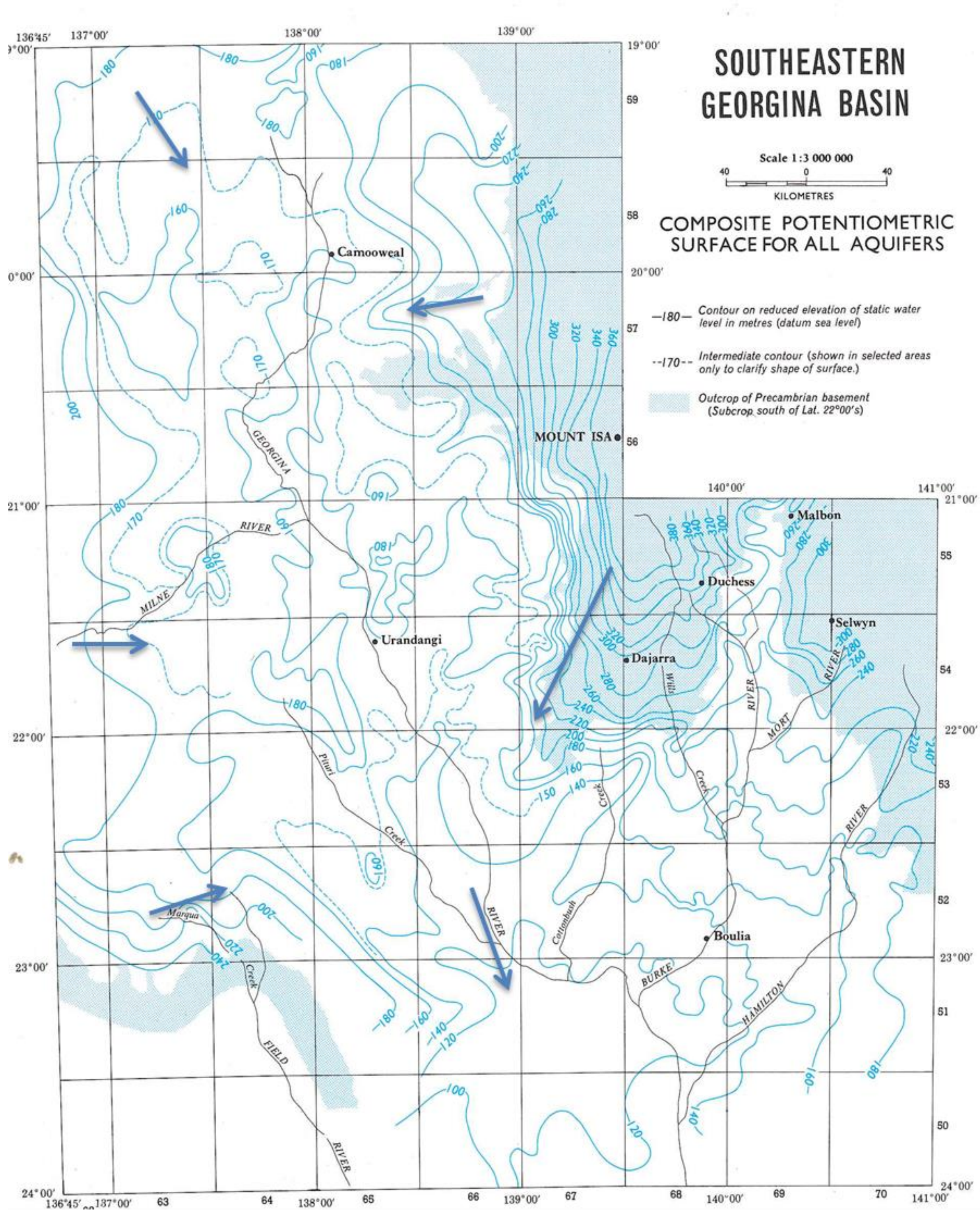

Figure C.44 Composite potentiometric surface for all aquifers in the in the southeastern Georgina Basin (adapted from Randal, 1978).

C.5.6.4 Groundwater planning and use

In Queensland, the Georgina Basin partly lies within the area covered by the Water Resource (Great Artesian Basin) Plan 2006 (Queensland Government, 2006) and the Water Plan (Georgina and Diamantina) 2004 (Queensland Government, 2004). Within the Northern Territory, parts of Georgina Basin lie within the Daly Roper, Western Davenport and Ti-Tree water control districts

(Northern Territory Government, 2016) under the Water Act 1992 (NT) (Northern Territory Legislation, 1992).

Groundwater extraction licences granted in the Western Davenport Water Control District for the financial year 2008–2009 totalled 2458 ML, of which approximately 81% was for horticulture, about 2% for roadhouses and 17% for public water supply to three Indigenous communities. Actual extraction for the 2008–2009 totalled 918 ML (DNREAS, 2011). Outside of Water Control Districts, groundwater use is generally not metered

Groundwater is the main water resource for consumptive use, including mining, irrigation and stock and domestic use in the in the Georgina Basin.

Table C.37 presents information from the Bureau of Meteorology's NGIS dataset (BoM, 2016) and shows summary information of registered bores in the basin.

Table C.37 Summary of groundwater bores and water use.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	5,797 (0.02)	
Purposes of registered bores (Top 5, number)	Stock	3,882
	Unknown	1,713
	Domestic Household	186
	Irrigated Agriculture	51
	Monitoring	43
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 28.3 Median: 80.8 90th Percentile: 152	

C.5.7 Surface water systems and hydrology

C.5.7.1 Surface Water Systems

The Georgina Basin lies mostly within the Carpentaria Coast Drainage Division, and according to the Bureau of Meteorology's Geofabric (BoM, 2014), the basin covers eleven river drainage networks, as presented in Figure B.15. These include nine in the Carpentaria Coast Drainage Division: the Calvert River; Flinders–Norman rivers; Limmen Bight River; McArthur River; Nicholson–Leichardt rivers; Robinson River; Roper River; Settlement Creek, and Towns River. The basin also lies within parts of the Diamantina-Georgina rivers (Lake Eyre Basin Drainage Division) and the Victoria-Wiso rivers (Tanami-Timor Sea Coast Drainage Division) catchments.

C.5.7.2 Surface water quality

Surface water quality for the Victoria River as measured by electrical conductivity ranged from 200 to 400 µS/cm (Kirby and Faulks, 2004). In the Roper River, electrical conductivity was higher, and ranged from 834 to 1873 µS/cm (Faulks, 2001), which make it unsuitable for human consumption.

A survey of several surface water bodies in the southeastern Georgina Basin by Randal (1978) showed the water suitable for stock purposes, with the exception of a sample taken at Young Australia Mine. It was noted that, although most samples were suitable for domestic use, water colour was milky due to clay suspension.

C.5.7.3 Surface water flow

Rainfall in the region is markedly seasonal, with the majority of the rainfall occurring under the influence of the northwest monsoon usually between late December and late February. Average rainfall varies from around 600–1000 mm in the north to 200–300 in the south (BoM 2017a).

Generally rivers are ephemeral and flow following the monsoonal rains, however a number of perennial rivers such as the Nicholson-Leichhardt Rivers (See Figure B.15) exist. The predominantly perennial Roper River has marked seasonal flow regime of high water levels during the wet season (November to April) and decreased water flow and river stage towards the end of the dry season. Approximately 96% of rainfall and 92% of runoff occurred during the wet season months according to the historical and recent climate records (CSIRO, 2009).

The Victoria River, one of the largest surface water catchments of the Georgina Basin (see Figure B.15), supports numerous waterholes, but very few are permanent. Although surface flow in the Victoria River ceases some weeks after the end of the wet season, long pools of permanent water occur along the river from Wave Hill settlement to its mouth (Randal, 1973).

C.5.7.4 Surface water planning and use

The Water Resource (Georgina and Diamantina) Plan 2004 (Queensland Government, 2004) allocates 1500 ML across the whole Diamantina–Georgina catchment area for projects of state significance. However, there is negligible use of surface water in the region, as most are reliant on groundwater for a dependable water supply (Queensland Government, 2004).

C.5.8 Groundwater–surface water interactions

Typically, rivers and watercourses in the basin lose surface water to the aquifers below. Recharge primarily by infiltration from these seasonal creeks, direct infiltration of rainfall, and infiltration of surface water, e.g. Tarrabool Lake.

Ephemeral and perennial groundwater springs exist in the Georgina Basin. Springs around the Cloncurry Complex are short-lived and only active after rain. Regionally fed springs from the Longsight Sandstone are present in the Eromanga Basin in the southwest. The Bureau of Meteorology Atlas of Groundwater Dependant Ecosystems (BoM 2017b) identified 7700 km^2 of moderate–high potential and identified aquatic and terrestrial Groundwater Dependant Ecosystems; some of these aquatic ecosystems are spring-fed.

C.5.9 Environmental assets

Within the Georgina Basin, there are 6,487 km^2 of Listed Nationally Important Wetlands, 7700 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential), and a total of 9666 km^2 of protected areas (such as national parks) are listed; there are no Ramsar wetlands (Table C.38).

Table C.38 Summary of environmental assets.

Environmental Assets		
Ramsar Wetlands	None	
Nationally Important Wetlands Top 5 by area (area km^2)	Thorntonia Aggregation	2,963
	Georgina River - King Creek Floodout	946
	Lake Sylvester	761
	Austral Limestone Aggregation	683
	Tarrabool Lake	469
	TOTAL WETLAND AREA	6,487
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	Nature Refuge	6,552
	National Park	2,628
	Conservation Reserve	376
	Biodiversity Hotspot	61
	Regional Park	50
	TOTAL PROTECTED AREA	9,666
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	7,700	

C.5.10 Social considerations

Information on population, land use type, and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in the Table C.39.

Table C.39 Summary of population, land use and aboriginal protected area.

GENERAL CHARACTERISTICS		
Population	3672	
Major population centres (two)	Boulia, Ali Curung	
Land use types Top 5 by area (area km^2)	Grazing native vegetation	307,206
	Other Protected areas	27,501
	Minimal use	16,579
	Nature Conservation	3,057
	Urban intensive uses	340
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	188,160	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

AERA (Australian Energy Resources Assessment) (2018) Australian Energy Resources Assessment interim report, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.ga.gov.au/aera>.

Ambrose GJ, Warner DS and Heugh JP (2012) Georgina Basin, Middle Cambrian petroleum systems and the search for unconventional hydrocarbons. In: Ambrose GJ and Scott J (Editors), Central Australian Basins Symposium III. Petroleum Exploration Society of Australia, Special Publication, 15 pp.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

Baraka (2012) Confirmation of oil in the southern Georgina Basin. Baraka Energy and Resources ASX Announcement. Viewed 16/01/2018, <http://www.barakaenergy.com.au/pdfs/2012-10-15-012917Confirmation_of_Oil_in_the_Southern_Georgina_Basin_15Oct2012.pdf>.

Bennett PJ, Philipchuk P and Freeman A (2010) Arthur Creek "hot shale": a Bakken unconventional oil analogy in the Georgina Basin of Northern Territory, Australia. AAPG International Conference and Exhibition, Calgary, Alberta, 11–15 September 2010, AAPG Search and Discovery Article #80125. Viewed 16/01/2018, <http://www.searchanddiscovery.com/pdfz/documents/2010/80125bennett/ndx_bennett.pdf.html>

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

BoM (Bureau of Meteorology) (2017a) Average annual Australian Rainfall 1961-1990. Viewed 03/09/2017, <http://www.bom.gov.au/jsp/ncc/climate_averages/rainfall/index.jsp>.

BoM (Bureau of Meteorology) (2017b) The Bureau of Meteorology Atlas of Groundwater Dependant Ecosystems. Viewed 28/07/2017, <http://www.bom.gov.au/water/groundwater/gde/>.

Boreham CJ and Ambrose GJ (2007) Cambrian petroleum systems in the southern Georgina Basin, Northern Territory, Australia. In: Munson TJ and Ambrose GJ (eds), Proceedings of the Central Australian Basins Symposium (CABS), Alice Springs, Northern Territory, 16–18 August, 2005. Northern Territory Geological Survey, Special Publication, 2, pp. 254–281.

Boult P and Bennett PJ (2012) Tectonic and stratigraphic mapping framework of the lower Arthur Creek, South Georgina Basin, Northern Territory, Australia. AAPG International Conference and Exhibition, Singapore, 16–19 September 2012, AAPG Search and Discovery Article #50752. Viewed 16/01/2018, <http://www.searchanddiscovery.com/pdfz/documents/2012/50752boult/ndx_boult.pdf.html>.

CAPAD (2016) Collaborative Australian Protected Area Database (2016) Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Carr LK and Korsch RJ (2011) Architecture of the Amadeus and Georgina basins, Northern Territory, based on Deep Seismic Reflection Line 09GA-GA1. In: Annual Geoscience Exploration Seminar (AGES) 2011. Record of abstracts. Northern Territory Geological Survey, Record, 2011-003, pp. 81–86.

Carr LK, Korsch RJ, Palu TJ and Reese B (2016) Onshore Basin Inventory: the McArthur, South Nicholson, Georgina, Wiso, Amadeus, Warburton, Cooper and Galilee basins, central Australia. Record 2016/04. Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/Record.2016.004>.

Central Petroleum (2012) ASX announcement and press release - Fractured basement hydrocarbon plays and “buried hill” plays in central Australia. Viewed 16/01/2018, <www.asx.com.au/asxpdf/20110718/pdf/41zthwzbm2qknq.pdf>.

Central Petroleum (2017) Southern Georgina Basin. Viewed 16/01/2018, <http://centralpetroleum.com.au/our-business/our-licence-areas/georgina-basin/southern-georgina-basin/>.

CSIRO (2009) Water in the Roper region, pp 59-120 in CSIRO (2009) Water in the Gulf of Carpentaria Drainage Division. A report to the Australian Government from the CSIRO Northern Australia Sustainable Yields Project. CSIRO Water for a Healthy Country Flagship, Australia. xl + 479pp.

DNREAS (2011) Department of Natural Resources, Environment, the Arts and Sport. Water Allocation Plan - Western Davenport Water Control District 2011-2021, Northern Territory Government, Darwin.

DNREAS (2009) Department of Natural Resources, Environment, the Arts and Sport. Ti-Tree Basin Water Resource Report, Northern Territory Government, Darwin.

DNRM (Department of Natural Resources and Mines) (2016a) Petroleum and gas production statistics (December 2016). Fractured basement hydrocarbon plays and “buried hill” plays in central Australia. Viewed 16/01/2018, <https://data.qld.gov.au/dataset/petroleum-gas-production-and-reserve-statistics/resource/9746212a-e0c6-484d-95ad-b2be1c46027d>.

DNRM (Department of Natural Resources and Mines) (2016b) Petroleum and gas reserves statistics (December 2016). Fractured basement hydrocarbon plays and “buried hill” plays in central Australia. Viewed 16/01/2018, <https://data.qld.gov.au/dataset/petroleum-gas-production-and-reserve-statistics/resource/351e9bd4-d9a1-4d60-a2ed-0e56cae79c4a>.

DNRM (Department of Natural Resources and Mines) (2017) Queensland’s unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DSWPET (2011b) Unconventional reservoir resource assessment, the Arthur Creek Formation, Georgina Basin, Australia. Central Petroleum Ltd, ASX Announcement, 11 April 2011. Viewed 16/01/2018, <www.asx.com.au/asxpdf/20110411/pdf/41xyzxdrpth0gg.pdf>.

Draper JJ (2007) Georgina Basin – an Early Palaeozoic carbonate petroleum system in Queensland. APPEA Journal, 7(1), 105–124.

Dunster JN, Kruse PD, Duffett ML and Ambrose GJ (2007) Geology and resource potential of the southern Georgina Basin. Northern Territory Geological Survey. Digital Information Package, DIP007, 232 pp.

EIA (Energy Information Administration) (2013) Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. United States Energy Information Administration, 730 p. Viewed 16/01/2018, <https://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf>.

Faulks JJ (2001) Roper River Catchment- An assessment of the physical and ecological condition of the roper river and its major tributaries. Technical Report No. 36/2001. Northern Territory Government.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Jacobson G and Lau JE (1987) Hydrogeology of Australia, Geoscience Australia. Viewed 10/07/2017, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7892-72bf-7506-e044-00144fdd4fa6>.

Jell PA (ed.) (2013) Geology of Queensland. Geological Survey of Queensland, Brisbane.

Jemena (2017) Northern gas pipeline. Viewed 16/01/2018, <http://jemena.com.au/industry/pipelines/northern-gas-pipeline>.

Kirby SL and Faulks JJ (2004) An assessment of the physical and ecological conditions of the Victoria River and its Major Tributaries Technical Report 40/2004K, Northern Territory Government.

Knapton A (2009) Integrated Surface - Groundwater Model of the Roper River Catchment: Part C: FEFLOW Groundwater Model. Gulf Water Study, Northern Territory Government Department of Natural Resources, Environment, the Arts and Sport, Technical Report No. 32/2009D.

Munro N (2012) Final Report: Brunette Downs Project, Natural Resources Exploration PTY LTD. Viewed 01/08/2017, <http://www.geoscience.nt.gov.au/gemis/ntgsjspui/bitstream/1/77092/1/GR168-10_2012_GAS_01.pdf>.

Munson TJ (2014) Petroleum geology and potential of the onshore Northern Territory, 2014. Northern Territory Geological Survey, Report 22, 242 pp.

Munson TJ, Kruse PD and Ahmad M (2013). Centralian Superbasin. In: Ahmad M and Munson TJ (Compilers), Geology and mineral resources of the Northern Territory. Northern Territory Geological Survey, Special Publication, 5, 22.1–22.19.

Northern Territory Government (2016) "NT Declared Water Control Districts", Map of Water Control Districts in the Northern Territory of Australia. Drawing Ref DENR2016025, November 2016. Viewed 29/09/2017, <http://www.ntlis.nt.gov.au/mpds/get_file?file_id=4072>.

Northern Territory Legislation (1992) "Water Act 1992", Act of the Parliament of the Northern Territory, as in force at 1 July 2016. Viewed 29/08/2017, <https://legislation.nt.gov.au/en/Legislation/WATER-ACT>.

NTGS (Northern Territory Geological Survey) (2017a) Geoscience exploration and mining information system (GEMIS) – Petroleum wells. Viewed 11/08/2017, <http://www.geoscience.nt.gov.au/gemis/ntgsjspui/handle/1/79187>.

NTGS (Northern Territory Geological Survey) (2017b) Northern Territory Statewide Geophysics – Seismic Lines. Viewed 11/08/2017, <http://www.ntlis.nt.gov.au/metadata/export_data?type=html&metadata_id=FB25348A02CB16B2E040CD9B2144584B>.

PetroFontier (2011) PetroFrontier Corp. announces successful drilling of Baldwin-2Hst1 horizontal well in the Georgina Basin, Australia. Viewed 22/01/2017, </http://petrofrontier.com/assets/files/press-releases/2011-10-11.pdf>.

Queensland Government (2006) “Water Plan (Great Artesian Basin) 2006”, legislation under the Water Act 2000 (Qld), current as at 3 July 2017. Viewed 04/08/2017, https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf>.

Queensland Government (2011) “Water Plan (Cooper Creek) 2011”, legislation under the Water Act 2000 (Qld), current as at 6 December 2016. Viewed 04/08/2017, <https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReCCPl11.pdf>.

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 22/01/2018, <https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells>.

Randal MA (1973) Groundwater in the Northern Territory Wiso Basin and Environs, Northern Territory. Bureau of Mineral Resources, Geology and Geophysics, Bulletin 123. Canberra.

Randal MA (1978) Hydrogeology of the southeastern Georgina Basin and environs, Queensland and Northern Territory. Queensland Department of Mines. Publication 366, April 1978.

Ransley TR, Radke BM, Feitz AJ, Kellett JR, Owens R, Bell J, Stewart G and Carey H (2015) Hydrogeological Atlas of the Great Artesian Basin, Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/9781925124668>.

Raymond OL (Coordinator) (2009) Surface geology of Australia 1:1 million scale digital geology data: Geoscience Australia, Digital Geology Map. Viewed 16/01/2018, <https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=69455>.

Ryder Scott Company Petroleum Consultants (2010) Evaluation of the hydrocarbon resource potential pertaining to certain acreage interests in the southern Georgina Basin, Northern Territory, Australia. Baraka Energy and Resources Ltd, ASX Announcement 13 December 2010. http://www.barakaenergy.com.au/pdfs/2012-10-15-004731Petroleum_Prospectivity__of_EP_127_and_128_8th_December.pdf

SAALNRMB (South Australian Arid Lands Natural Resource Management Board) (2009) Explanation of the Water Allocation Plan for the Far North Prescribed Wells Area. South Australian Arid Lands Natural Resources Management Board, South Australia.

Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Final Report, March 2018. Viewed 23/04/2018, <https://frackinginquiry.nt.gov.au/inquiry-reports?a=494286>.

Smith KG (1972) Stratigraphy of the Georgina Basin. Bureau of Mineral Resources, Geology and Geophysics, Bulletin 111. Canberra.

Smith TE, Carr LK, Edwards DS, Hall L, Kelman AP, Laurie JR, le Poidevin S and Nicoll RS (2013) Georgina Basin Biozonation and Stratigraphy, Chart 41. Geoscience Australia. Geocat 83216.

Statoil (2014) Statoil 2014 Annual Report. Viewed 22/01/2018, <https://www.statoil.com/content/dam/statoil/documents/annual-reports/2014/Statoil-20-F-2014.pdf>.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

UPR (Upstream Petroleum Resources Working Group) (2015) Coal seam, shale and tight gas in Australia: resources assessment and operation overview 2015, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/UPR%20Unconventional%20Resources%20Report%202015%20-%20Final_0.pdf>.

Verma MN and Jolly PB (1992) Hydrogeology of Helen Springs, Power and Water Authority, Darwin.

Vu TAT, Horsfield B and di Primio R (2011) Gas shale potential of the Amadeus and Georgina basins, Australia: preliminary insights. Geoscience Australia Record, 2011/10, 39 pp. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7893-007c-7506-e044-00144fdd4fa6>.

Walter MR, Veevers JJ, Calver CR and Grey K (1995) Neoproterozoic stratigraphy of the Centralian Superbasin, Australia. Precambrian Research 73, 173–195.

Willink R and Allison M (2015) Exploring unconventional plays in the Georgina Basin, central Australia: will the real Arthur Creek Formation hot shale please stand up! The APPEA Journal and Conference Proceedings, DVD 55, extended abstract, 8 pp.

C.6 Gippsland Basin (Onshore)

Table C.40 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	Victoria
Area	~15,000 km2
Max. basin depth/ sediment thickness	~ 4,000 m
Age range	Cretaceous–Cenozoic
Depositional setting	Fluvial overlain by deltaic and marine sediments
Regional structure	Extensional basin with two phases of post-rift compression
EXPLORATION STATUS	
Seismic lines	3,620 km 2D seismic
Number of wells	198
Exploration status - conventional	Mature
Exploration status – shale/ tight gas	Preliminary exploration
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Austral 2 and 3)
Prospectivity	Moderate
Conventional discoveries	Lakes Entrance oil
Hydrocarbon production – total to date	7.8 Tcf cumulative conventional gas production offshore; no production onshore (current to 2014; AERA, 2018)
2P Reserves	4.44 Tcf conventional reserves offshore; no reserves onshore (current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	7.8 Tcf conventional reserves offshore; no reserves onshore; see below for shale/ tight gas (current to 2014; AERA, 2018)
Undiscovered resource estimates	7,910 PJ (Core, 2014) offshore resources; no prospective conventional resources onshore; see below for prospective shale/ tight gas resources
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Tight gas; ?shale gas
No. of wells targeting shale/tight gas plays	6
Production – shale/ tight gas	Wombat, Trifon-Gangell fields
2P Reserves – shale/ tight gas	No reserves booked (AERA, 2018)
Remaining resources (reserves + contingent resources) – shale/ tight gas	0.72 Tcf (Table A.3; Lakes Oil, 2017; AERA, 2018)
Undiscovered resource estimates – shale/ tight gas	Total potentially recoverable resources in the Strzelecki Group of 13.6 Tcf of tight gas (assessment area 4,191 km2) and 5.6 Tcf of shale gas (assessment area 2,179 km2) (assuming 5% recovery factor at P50; GA, 2017; AERA, 2018).

Hydrocarbon shows, tests – shale/ tight gas	Several drill stem tests (DST), Fracture stimulation Wombat 2 & Wombat 3 and an extended production test Wombat 3

C.6.1 Basin Geology

The Gippsland Basin is a Cretaceous–Cenozoic extensional basin in southeastern Victoria (Figure C.45). The basin covers an area of about 49,000 km^2, two-thirds of which is located offshore. The Gippsland Basin formed as a result of the breakup of eastern Gondwana in the Late Jurassic–Early Cretaceous. The basin fill is characterised by dominantly siliciclastic sedimentary sequences from the Upper Cretaceous to Eocene and by carbonate sequences from the lower Oligocene to Holocene. The Early Cretaceous Strzelecki Group is the basal sedimentary unit deposited during the initial rift phase (Duddy, 2003) and is dominated by volcanoclastic sediments (Figure C.46). With the opening of the Tasman Sea, the Upper Cretaceous to Paleogene Latrobe Group was deposited in fluvial-lacustrine to marginal marine depositional environments as rifting continued in the basin (Bernecker and Partridge, 2005).

Post-rift sedimentary processes dominated the Gippsland Basin from the early Oligocene, with the deposition of the basal unit of the carbonate–dominated Seaspray Group, the Lakes Entrance Formation and equivalent sequences onshore. These onlapping, marly sediments provide the principal regional seal across the basin. Subsequently, deposition of the thick Gippsland Limestone, also part of the Seaspray Group, provided the critical loading for the source rocks of the deeper Latrobe and Strzelecki groups, with the majority of hydrocarbon generation occurring in the Neogene.

In the offshore part of the basin, several giant oil and gas fields were discovered in the late 1960s (Rahmanian et al., 1990; Woollands and Wong, 2001). The basin developed into Australia's premier hydrocarbon province, maintaining that status until large-scale hydrocarbon production on the North West Shelf was established in the 1990s. Most of the hydrocarbon accumulations in the offshore Gippsland Basin are hosted by the Latrobe Group. The syn-rift successions of the Strzelecki Group are the focus for unconventional tight gas exploration.

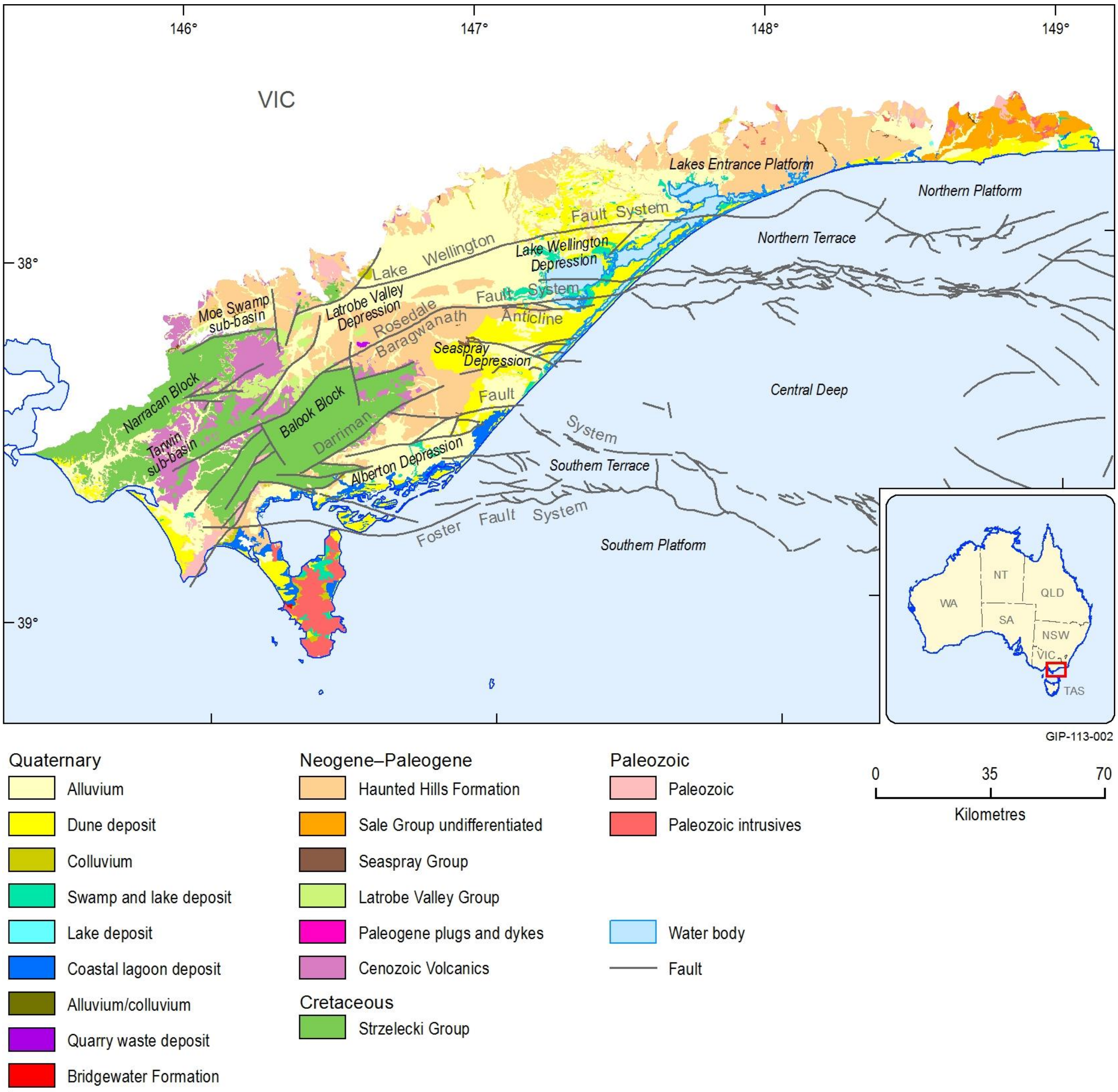

Figure C.45 Geology of the onshore Gippsland Basin including faults and structural elements (Yates et al., 2015).

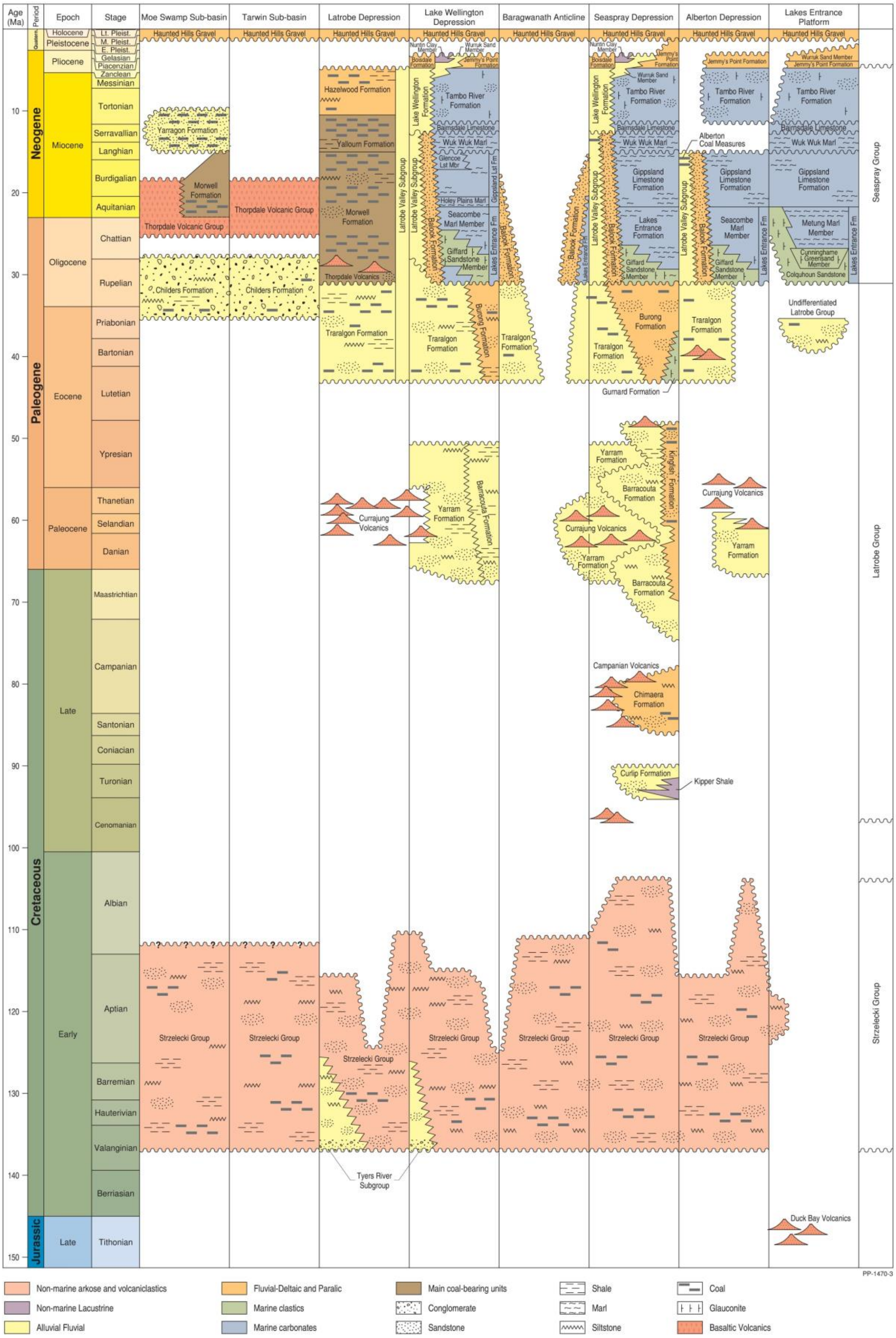

Figure C.46 Stratigraphy of the onshore Gippsland Basin (Yates et al., 2015), refer to Figure C.45 for the location of the structural elements.

C.6.2 Petroleum data coverage

The onshore basin has a long history of petroleum exploration with 197 wells drilled since 1886, the majority of which have targeted petroleum accumulations in the Latrobe Group (GSV, 2017a). Approximately 3620 line km of 2D seismic data has been acquired in the onshore basin, mainly concentrated in the eastern part of the basin (GSV, 2009; GSV, 2017b; Figure C.47). Although numerous oil and gas shows have been recorded, no conventional discoveries were made except for relatively small volumes of oil at Lakes Entrance that were produced in the 1920s and 1930s. The two Petroleum Exploration Permits (PEPs) and two Petroleum Retention Leases (PRLs) in the onshore part of the basin are currently suspended. There is also complete coverage of gravity and airborne magnetics data across the basin of varying quality and resolution.

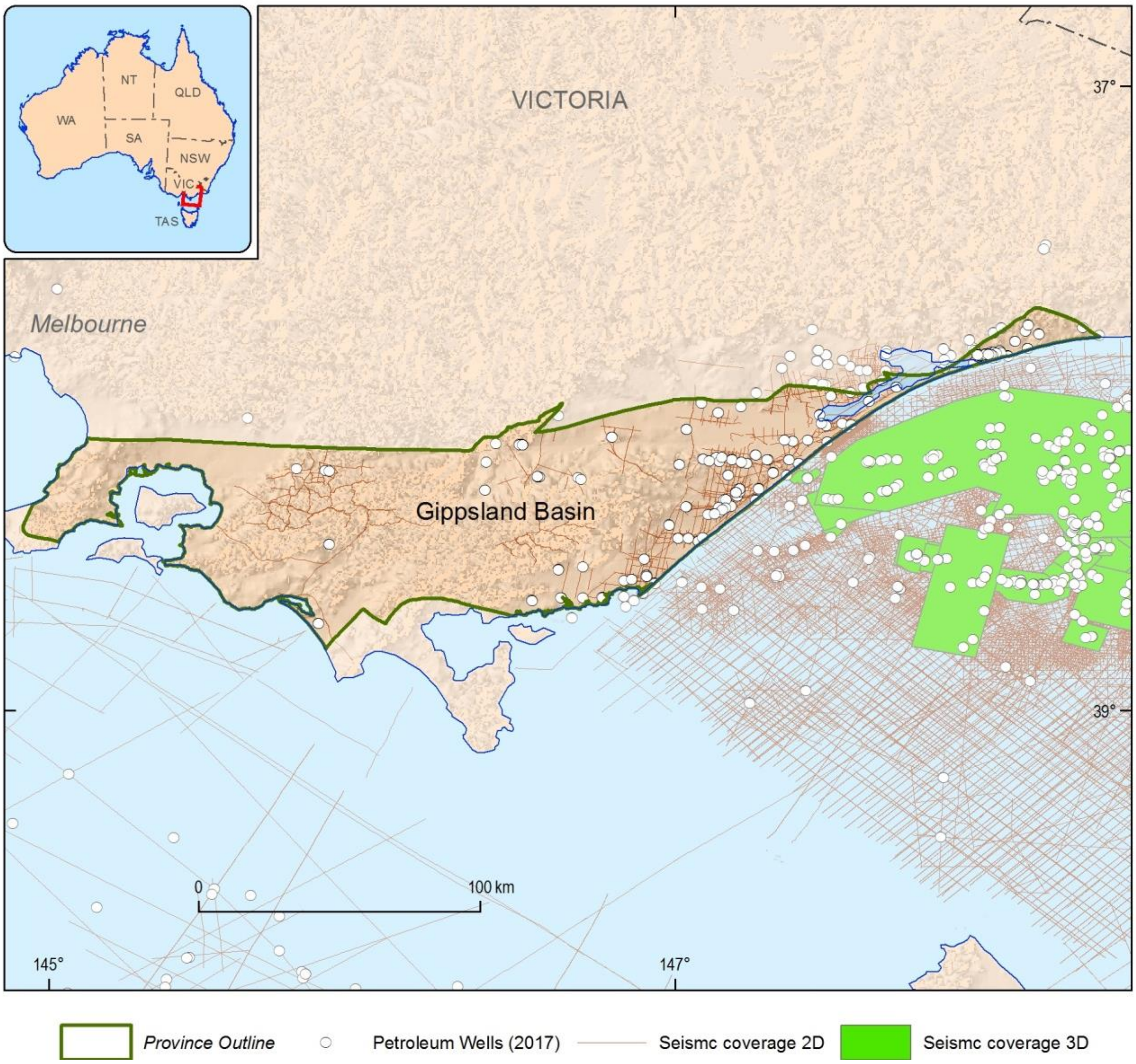

Figure C.47 Gippsland Basin petroleum exploration wells and seismic data coverage. Gippsland Basin outline from Stewart et al. (2013). Petroleum well data from GSV (2017a). Seismic data coverage from GSV (2009) and GSV (2017b).

C.6.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Gippsland Basin is summarised in Table C.40.

Although the offshore Gippsland Basin has a significant production history of conventional petroleum, only relatively minor unconventional exploration has been conducted onshore. Lakes Oil N.L. has drilled tight gas reservoirs in Strzelecki Group in the Seaspray Depression (Figure C.48), and has conducted fracture stimulation and an extended production test. They report independently estimated 2C recoverable gas of 0.329 Tcf for the Wombat accumulation and 0.39 Tcf for the Trifon-Gangell accumulation, which represents the only relatively well-constrained estimate of tight gas potential in the basin (Lakes Oil, 2017; see also AERA, 2018). There are no estimates or reserves for shale gas in the Gippsland Basin, and no petroleum exploration permit holder has indicated that they were searching for shale gas in the region (Goldie Divko, 2015).

A recent volumetric study by Geoscience Australia based on publicly available data estimates total potentially recoverable resources in the Strzelecki Group of 13.6 Tcf of tight gas (assessment area 4,191 km^2) and 5.6 Tcf of shale gas (assessment area 2,179 km^2) (assuming 5% recovery factor at P50; GA, 2017; AERA, 2018). It should be noted that publically available data specifically relevant to Gippsland Basin shale and tight resource plays is very limited, necessitating the use of analogues and geologically reasonable assumptions. Significant improvements could be made to the reliability of this assessment if more data were available). In the medium term (10 to 15 years) only a small amount of the gas-in-place could be extracted because of the very early stage of exploration and the time needed to better define resources prior to production (AERA, 2018).

Goldie Divko (2015) present 3 scenarios for tight/ shale gas development. The regional scenario includes all tight/shale sub-crop areas and has an area of 5,375 km^2. The second development scenario is at a sub-regional scale. This covers an area of 438 km^2 and encompasses the identified prospects, fields and all areas in between (Figure C.48). The third scenario is at a prospect/ field scale and is focused on gas shows observed within structural traps at top Strzelecki Group level (area of 8.4 km^2).

The sub-regional development scenario is here considered to best represent the area with the potential to be developed for tight gas in a ten year timeframe, if there were no other impediment to development (e.g. regulatory restrictions). However, too little is understood about the shale gas potential for development of any shale gas play in the basin within a 10 year timeframe.

Data for the key unconventional hydrocarbon targets are summarised in Table C.41.

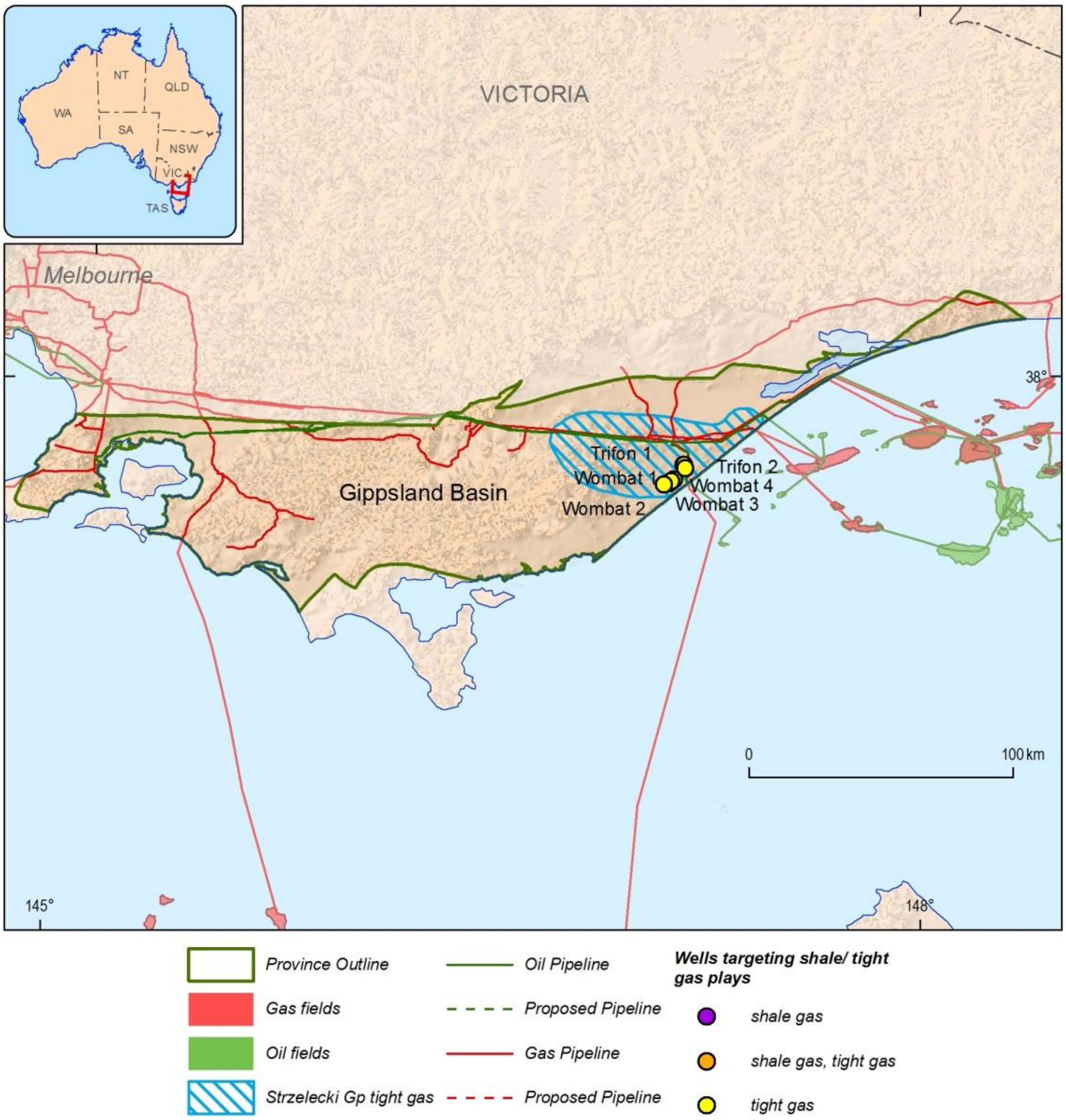

Figure C.48 Wells targeting shale or tight gas plays and approximate play extents modified from Geoscience Australia (2017). Strzelecki Group play extent based on the sub-regional scale tight/shale development scenario from Goldie Divko (2015). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.41 Summary of shale and tight gas plays with the potential to supply gas to market in a 5 to 10 year timeframe. Compiled from Goldie Divko (2015) and GA (2017). Note too little is understood about the shale gas potential for development of any shale gas play in the basin within a 10 year timeframe, so this play is not included here.

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rocks(s)	Source rock TOC (%)	Source rock maturity Ro(%)	Play type	Exploration status
Strzelecki Group	Early Cretaceous	Fluvial	1400	up to 3000	Type II/III to Type III; coal, DOM	0.4–20	0.5–1.3	Tight gas	Preliminary exploration

C.6.4 Gas market access and infrastructure

The Gippsland Basin region is serviced by an extensive road system. Exxon Mobil's Barry Beach terminal provides port access to the Gippsland Basin (Figure C.49).

Petroleum infrastructure is well developed, with a network of pipelines transporting hydrocarbons produced offshore to onshore petroleum processing facilities at Longford and Orbost. The majority of Victoria's oil and gas is processed at Exxon Mobil's Longford Crude Stabilisation Plant. Crude oil and gas are transported via pipeline from offshore facilities in the Gippsland Basin to the Longford Crude Stabilisation Plant where they are separated into wet gas, LPG and stabilised crude oil. The stabilised crude oil is piped to Long Island Point on Westernport Bay where it is either shipped, or piped to the refineries in Altona or Geelong. Gas is fed into the Eastern Gas Pipeline which delivers gas to New South Wales, the Longford-Tasmania gas pipeline or into the local Victorian gas supply network. Santos's Patricia Baleen Gas Processing Plant near Orbost in eastern Victoria feeds gas into the Eastern Gas Pipeline when operational (Department of Economic Development, Jobs, Transport and Resources, 2017). Initially built to process gas from the Patricia and Baleen fields, and later the Longtom field, the plant is currently not operational. The plant is expected to be upgraded to process up to 74 TJ of gas per day from the Sole field when it is developed, and to be fully operational again by 2019 (Santos, 2015; Cooper Energy, 2017). Further details are summarised in Table C.42.

Table C.42 Summary of market access and infrastructure. Pipeline information from AER (2017). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	Currently supplies to the East Coast Gas Market
Gas pipelines	• Victorian Transmission System (GasNet) - capacity 1030 TJ/ Day • South Gippsland ; Tasmania Gas - capacity 250 TJ/ Day • Vic–NSW Interconnect - capacity 153 TJ/ Day (196 reverse) • Eastern Gas Pipeline (Longford to Sydney) – capacity 351 TJ/ Day • Tasmanian Gas Pipeline (Longford to Hobart) - capacity 129 TJ/ Day
Gas processing facilities	Longford; Long Island; Patricia/Baleen
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	<100 km
Road and rail access	Very well serviced
Approximate development timeframe	5–10 years

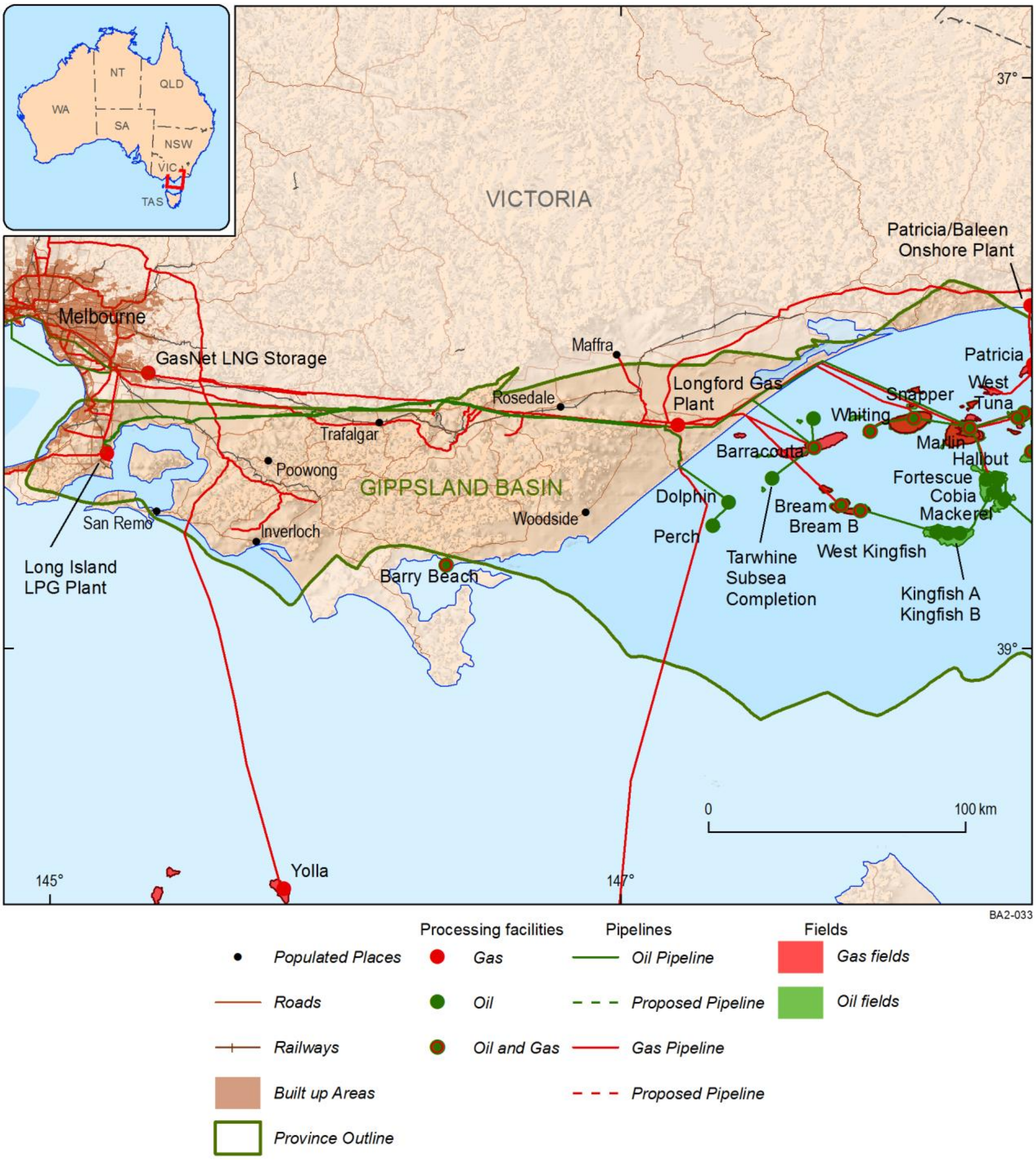

Figure C.49 Gippsland Basin petroleum fields, pipelines and production facilities. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

C.6.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia. In March 2017, the Resources Legislation Amendment (Fracking Ban) Bill 2016 passed the Victorian Parliament (Victorian Government, 2017). This bill permanently bans all onshore unconventional gas exploration and development, including hydraulic fracturing and coal seam gas and extends the moratorium on conventional onshore gas exploration and development to 30 June 2020.

C.6.6 Hydrogeology and groundwater

C.6.6.1 Groundwater systems

Extensive aquifer and aquitard mapping of the Gippsland Basin has been undertaken (GHD, 2012; Sinclair Knight Merz, 2009). Recent studies (Yates et al., 2015; DELWP and GSV, 2015) have provided an overview of the hydrogeology of the Gippsland Basin. A brief summary of the aquifer systems in the onshore Gippsland Basin is provided in the following sections. The classification of aquifers is taken from the Victorian Aquifer Framework (GHD, 2012). Although the term 'Tertiary' is now obsolete and replaced with the use of 'Paleogene' and 'Neogene', this report retains the term 'Tertiary' as per its use in the reviewed literature and its use in the Victorian Aquifer Framework.

There are four main aquifer systems identified within the onshore Gippsland Basin (Figure C.50): upper, middle and lower aquifer systems made up of Cenozoic strata, underlain by a Cretaceous and Palaeozoic bedrock system.

C.6.6.1.1 Upper aquifer system (Miocene to Quaternary): Sale Group sediments

The upper aquifer system includes the lower permeability unit of the Boisdale Formation (the Nuntin Clay Member), and the gravelly Haunted Hills Formation, Eagle Point Sand Member and various undifferentiated Quaternary deposits. Both of these aquifers occur over much of the Gippsland Basin, they are clay-dominated and low-yielding, however in some areas well-developed sand and gravel layers can produce significant quantities of groundwater. The Haunted Hills Formation can range in thickness between 5 and 100 m (Hofmann, 2011). The aquifers of the Haunted Hills Formation and Quaternary deposits are generally within 30 m of the land surface and are unconfined to semi-confined (Walker and Mollica, 1990).

C.6.6.1.2 Middle aquifer system (Oligocene to Miocene): Latrobe Valley Group and Seaspray Group sediments

The middle aquifer system consists of a number of aquifers (the Upper Tertiary Aquifer, the Upper Mid-Tertiary Aquifer and the Lower Mid-Tertiary Aquifer) and aquitards (the Upper Tertiary Aquitard and the Upper Mid-Tertiary Aquitard). It is found in three regions in the onshore portion of the Gippsland Basin, with each region having relatively distinct hydrogeological properties. In the east (near Orbost) and the south, the system is dominated by marine rocks, limestones and marls of the Seaspray Group. Heading west and north, the sandstone of the Balook Formation (deposited as barrier sands with interbedded clays) dominates the system. Heading further west and north into the Latrobe Valley Depression, alluvial and fluvial sediments, sandstones, coal, siltstones and shales of the Latrobe Valley Group dominate.

C.6.6.1.3 Lower aquifer system (Eocene to Oligocene): Latrobe Group sediments and volcanics

The lower aquifer system extends over most of the onshore Gippsland Basin as well as offshore. Included in this group are the Latrobe Group sediments and the Thorpdale and Currajung volcanics. The Latrobe Group consists of two aquitards and two aquifers: the T1 coal seam aquitard, which overlies and confines the T1 aquifer; and the T2 coal seam aquitard, which overlies and confines the T2 aquifer (Schaeffer, 2008) (Figure C.50). These aquifers are generally high yielding (up to 100 L/s) and of good quality, forming the most reliable groundwater source in the onshore part of the Gippsland Basin (Hatton et al., 2004). The T1 aquifer is regionally extensive; the T2 aquifer is more prominent in the southern portion of the Gippsland Basin (Schaeffer, 2008).

C.6.6.1.4 Bedrock aquifer system (Cretaceous, and Ordovician to Carboniferous): Strzelecki Group and Paleozoic basement sediments and intrusives

The Early Cretaceous Strzelecki Group and the underlying Paleozoic rocks are often referred to as groundwater basement due to their low matrix permeability. While not transmitting large quantities of groundwater in the Gippsland Basin, these aquifers are known to maintain baseflow in many of the streams and rivers in the Gippsland Basin (Nicol, 2010).

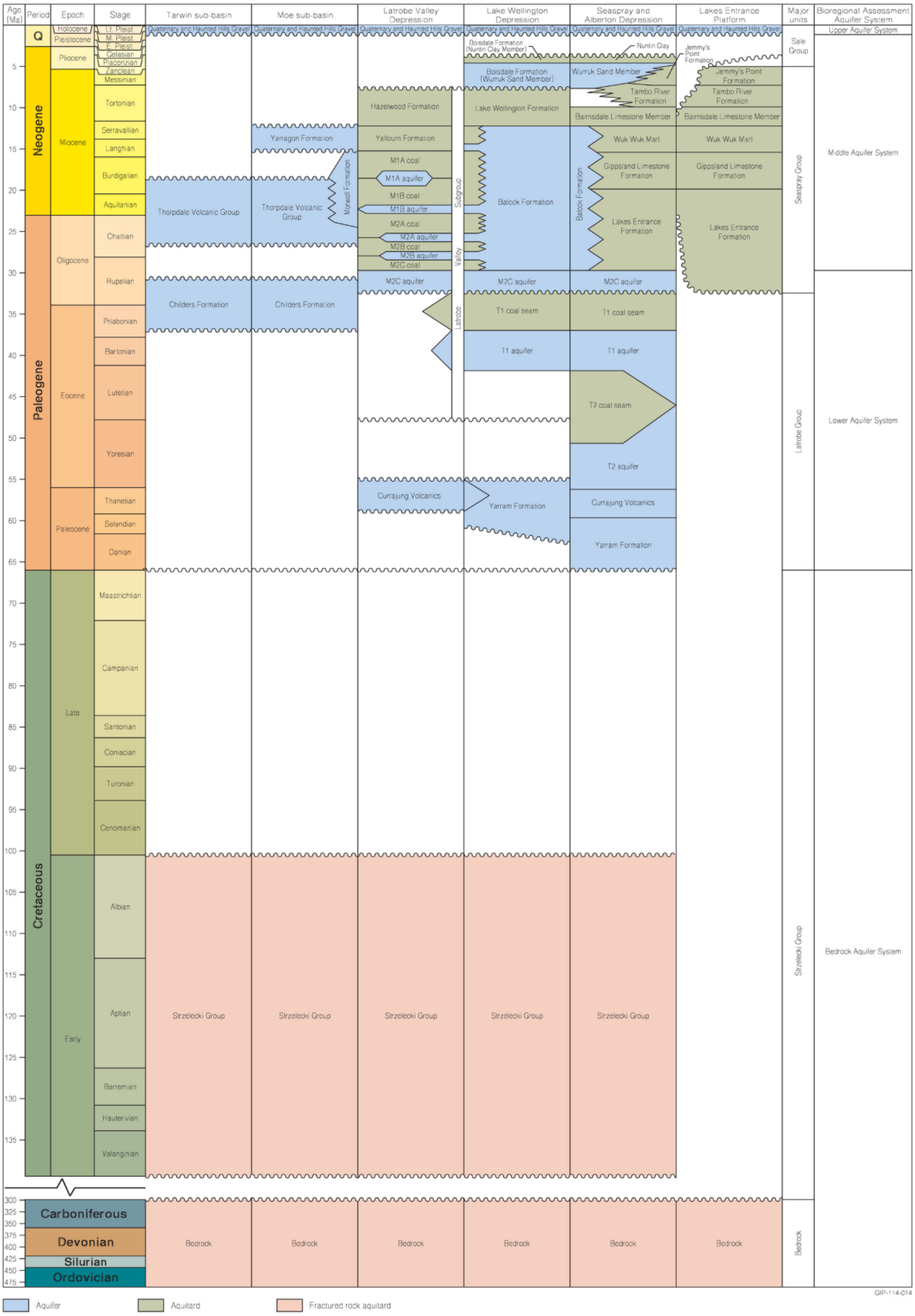

Figure C.50 Hydrostratigraphy of the onshore Gippsland Basin (Source: Yates et al., 2015).

C.6.6.2 Groundwater quality

A number of aquifers in the Gippsland Basin are high yielding and contain good quality groundwater. Groundwater quality varies with depth as well as across the basin, within and between the different aquifers.

Low salinity groundwater, with total dissolved solids (TDS) values below 1000 mg/L, is found in the upper aquifer system in the Lake Wellington catchment and Mitchell River valley, as well as around the regions of Moe and Orbost, the South Gippsland Coast and in the upper valleys of the Macalister Mitchell, Tambo and Snowy rivers (Southern Rural Water, 2012). Groundwater within the surficial aquifers across the reminder of the basin is generally of poorer quality (TDS>1000 mg/L).

The uppermost part of the middle aquifer system, the Boisdale Formation (Wurruk Sand Member) is an important aquifer within the Gippsland Basin due to its high pumping yields and generally low salinity. The groundwater salinity is generally less than 500 mg/L TDS, however higher salinity groundwater (500–3500 mg/L TDS) is evident in the region between Rosedale and Maffra in the north; in the eastern part of the aquifer, towards Lakes Entrance; and in the southwest and south along the coast. Groundwater salinity in the lower aquifer system is generally below 3500 mg/L TDS. Salinity generally increases towards the east. In general, areas of higher salinity groundwater (3500–13,000 mg/L TDS) are evident in the bedrock aquifer, particularly in the region of Heyfield, Metung–Lakes Entrance, Orbost and Marlo regions.

C.6.6.3 Groundwater flow

The groundwater flow systems in the Gippsland Basin are complex as a result of variability in lithostratigraphy and hydraulic properties as well as tectonic movements experienced after deposition. Some aquifers extend over large areas, and partly into the offshore parts of the basin, through complex geological structures, while other aquifers are only of local extent (Schaeffer, 2008). The lithologies of the regional aquifer systems are relatively consistent in a north–south direction across the onshore portion of the basin. However, from west to east, the lithologies vary from being predominantly coal rich, to a sandy sequence and then predominantly limestone and marl (Schaeffer, 2008). In general, groundwater flow generally mimics topography and flow is towards the coast or local and regional discharge features in the basin.

C.6.6.4 Groundwater planning and use

Groundwater management in the Gippsland Basin is organised into several groundwater catchment areas. Within these groundwater catchment areas, where there is more intensive groundwater use, groundwater is managed within groundwater management units (GMUs) called either water supply protection areas (WSPAs) or groundwater management areas (GMAs). Groundwater is managed in these GMUs under conditions set out by local management plans for each GMU.

Groundwater is used for irrigation, urban water supply, stock and domestic, industrial and power station cooling purposes. It is also an important water source for many ecosystems across the

Gippsland Basin. Groundwater from shallow and deep aquifers either supplies or supplements the water supply to a number of towns across Gippsland, including: Sale, Boisdale, Briagolong, Wurruk and Yarragon. Sale's town water supply has been solely sourced from groundwater since 1970 (Schaeffer, 2008). Groundwater has also become increasingly investigated as a contingency water supply for other towns throughout the Gippsland Basin (e.g. Thorpdale) (Gippsland Water, 2012).

There are about 164 GL of licensed groundwater entitlements in the Gippsland Basin. In any managed groundwater area, the licensed entitlement is capped at the permissible consumptive volume.

Table C.43 below presents information from the NGIS (BoM, 2016) and shows summary information of registered bores in the basin.

Table C.43 Summary of groundwater bores and water use in the Gippsland Basin

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	32,564 (2.82)	
Purposes of registered bores (Top 5, number)	Exploration	19,424
	Stock	4356
	Unknown	3502
	Domestic Household	1470
	Monitoring	1177
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 5.5 Median: 34 90th Percentile: 207.6	

C.6.7 Surface water systems and hydrology

C.6.7.1 Surface water systems

The surface water systems in the Gippsland Basin are part of four river regions: South Gippsland, Mitchell–Thomson Rivers, Snowy River, and East Gippsland (Bureau of Meteorology, 2014). These river basins are presented in Figure B.16. The majority of the basin is located in the Mitchell–Thomson rivers and South Gippsland River regions and only a small portion of the basin (<10% of the area) is located in the Snowy and East Gippsland river regions.

The southwestern part of the Gippsland Basin is part of the South Gippsland River Region (Figure B.16). The surface water systems of this river region include several rivers (e.g. Tarwin River, Albert River and Tarra River) and creeks (e.g. Merriman Creek and Bruthen Creek) as well as freshwater and saline-water wetlands. A notable feature of the system is its floodplain providing rich agricultural land as well as areas of high conservation value, such as Wilsons Promontory, Corner Inlet and the Nooramunga Marine and Coastal Park. Much of the Gippsland Basin overlaps the Mitchell–Thomson river region (Figure B.16). The surface water systems of this river region include several large rivers including the Latrobe River, Thomson River, Macalister River, Mitchell River and Tambo River as well as wetlands and saltwater pans.

A small proportion of the Gippsland Basin is located in the Snowy River Region. The surface water system of this river region includes several large rivers and creeks as well as wetlands on the floodplain. The eastern end of the Gippsland Basin is part of the East Gippsland River Region. The surface water system of the river region includes four large rivers and several creeks as well as freshwater and saline water wetlands

C.6.7.2 Surface water quality

Water quality as measured by electrical conductivity (EC) and turbidity varies between water courses across the basin. The EC and turbidity values are very high in part of the South Gippsland river region compared to other river basins in the Gippsland Basin. In general, both salinity and turbidity are within the water quality guideline values of 500 µS/cm and 10 NTU (Nephelometric Turbidity Unit), respectively.

C.6.7.3 Surface water flow

The surface water flow in the Gippsland Basin originates from four river regions (South Gippsland, Mitchell–Thomson, Snowy and East Gippsland) by its numerous headwater streams. Each of these river regions are characterised by large variations in discharge and flow duration. There are 13 streamflow monitoring stations across the Gippsland Basin which measured annual flow and runoff at different time intervals (Table C.44).

Table C.44 List of thirteen stream gauges in the Gippsland Basin region, located in four river regions, as compiled by Yates et al., (2015).

Gauge number	Name of stream gauge	River Region	Catchment area (km^2)	Mean annual flow (GL)	Mean annual runoff (mm)	Data period
GS 221225	Bemm River upstream of pump house	East Gippsland	935	122	131	1966–1975 and 2009–present
GS 223209	Tambo River at Battens Landing	Mitchell–Thomson	2,781	206	74	1977–present
GS 223210	Nicholson River at Sarsfield	Mitchell–Thomson	471	41	87	1997–present
GS 224200	Mitchell River at Bairnsdale	Mitchell–Thomson	4,425	331	75	1889–present
GS 225201	Avon River at Stratford	Mitchell–Thomson	1,485	162	109	1976–present
GS 225232	Thomson River at Bundalaguah	Mitchell–Thomson	3,538	373	105	1976–present
GS 226227	Latrobe River at Kilmany South	Mitchell–Thomson	4,464	502	112	1976–present
GS 222200	Snowy River at Jarrahmond	Snowy River	13,420	912	68	1889–present
GS 227200	Tarra River at Yarram	South Gippsland	215	32	151	1946–present
GS 227201	Bruthen Creek at Woodside	South Gippsland	174	29	166	1946–1960
GS 227202	Tarwin River at Meeniyan	South Gippsland	1,067	254	238	1955–present
GS 227216	Albert River at Hiawatha (Below Falls)	South Gippsland	41	14	337	1964–1989
GS 227240	Merriman Creek at Prospect Road Seaspray	South Gippsland	529	28	52	1983–present

Source: Department of Environment and Primary Industries (2014b). Mean annual flow statistic sourced from Bureau of Meteorology (2014)

C.6.7.4 Surface water dams, planning and use

Surface water is used for irrigation, stock and domestic, urban and commercial and power generation in the Gippsland Basin. Irrigation is the highest category of surface water use in the basin, including the Macalister Irrigation District around Maffra that sources water from Lake Glenmaggie on the Macalister River (Figure C.51), in the Mitchell–Thomson rivers catchment area (Figure B.16). The surface water entitlement for 2014–2015 in the Gippsland Basin was 795,791 ML and the use was 463,098 ML for the same period (DELWP, 2016). The majority of surface water entitlements and usage occur in the Mitchell–Thomson and Latrobe river regions.

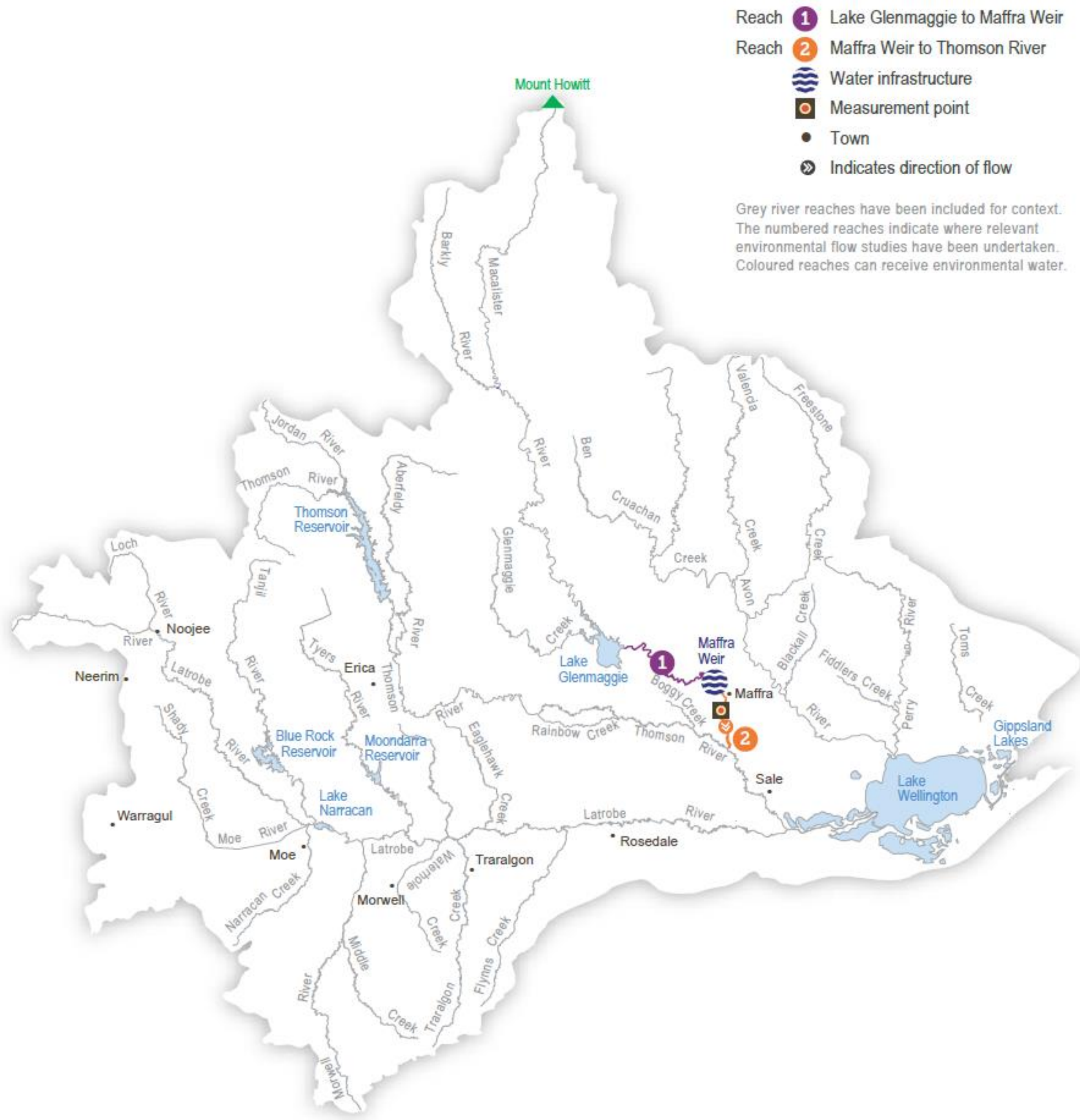

Figure C.51 Location of Lake Glenmaggie on the Macalister River (VEWH 2017).

C.6.8 Groundwater – surface water interactions

Studies have shown that there is a strong hydraulic connection between the river and the water table along a number river reaches in the onshore Gippsland Basin (SKM 2009, GHD 2012; DELWP and GSV 2015). Groundwater-surface water interactions are shown to be dynamic spatially (from highlands to lowlands) and temporally (seasonally to decades). In general, during high flow periods the rivers in the basin are likely to be discharging to the water table and vice versa during low flow periods.

C.6.9 Environmental assets

Within the Gippsland Basin there are 1,553 km^2 of Listed Nationally Important Wetlands, 1,800 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential) and a number of Ramsar wetlands. A total of 1,210 km^2 of protected areas (such as national parks) are listed (Table C.45).

Table C.45 Summary of environmental assets.

Environmental Assets		
Ramsar Wetlands	Gippsland Lakes	
	Western Port	
	Corner Inlet	
Nationally Important Wetlands Top 5 by area (area km^2)	Western Port	892
	Lake Wellington Wetlands	279
	Corner Inlet	167
	Lake Victoria Wetlands	93
	Lake King Wetlands	48
	TOTAL WETLAND AREA	1,553
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	Natural Features Reserve	259
	National Parks Act Schedule 4 park or reserve	211
	Conservation Park	199
	State Park	199
	National Park	163
	TOTAL PROTECTED AREA	1,210
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential *(area km^2).*	1800	

C.6.10 Social considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in the Table C.46.

Table C.46 Summary of population, land use and aboriginal protected area.

GENERAL CHARACTERISTICS		
Population	396,194	
Major population centres (Top two)	Mornington Peninsula, Latrobe Valley	
Land use types Top 5 by area (area km^2)	Grazing modified pastures	4,557
	Plantation forestry	2,528
	Nature Conservation	1,302
	Urban intensive uses	908
	Rural residential and farm infrastructure	817
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	2051	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

Bernecker T and Partridge AD (2005) Approaches to palaeogeographic reconstructions of the Latrobe Group, Gippsland Basin, SE Australia. APPEA Journal 45, 581–600.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric ("Geofabric"), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

CAPAD (2016) Collaborative Australian Protected Area Database, 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Cooper Energy (2017) Sole gas project ASX announcement 27 February 2017. Viewed 15/03/2017, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2017.02.27-ASX-Sole-Gas-Project.pdf>.

Core (2014) Gas reserves and resources, eastern and southeastern Australia. Core Energy Group report to the Australian Energy Market Operator. Viewed 09/08/2017, <https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2015/Core--Gas-Reserves-and-Resources.pdf>.

Department of Economic Development, Jobs, Transport and Resources (2017) Viewed 15/03/2017, < http://earthresources.vic.gov.au/earth-resources/victorias-earth-resources/petroleum/petroleum-processing-plants,-refineries-and-infrastructure>.

DELWP (Department of Environment, Land, Water and Planning) (2016) Victorian Water Accounts 2014-2015 – A statement of Victorian water resources. Department of Environment, Land, Water and Planning, Victoria. October 2016.

DELWP (Department of Environment, Land, Water and Planning) and (GSV) Geological Survey of Victoria (2015) Onshore natural gas water science studies — Gippsland region assessment of potential impacts on water resources. Department of Environment, Land, Water and Planning, Melbourne, June 2015.

Duddy IR (2003) Mesozoic, a time of change in tectonic regime. In: Birch WD (Ed.) Geology of Victoria, Geological Society of Australia Special Publication 23, Geological Society of Australia (Victoria Division), 239–286.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

GA (Geoscience Australia) (2017) Interim Gippsland Basin unconventional resource assessment. Viewed 16/01/2018, <http://www.ga.gov.au/metadata-gateway/metadata/record/104422>.

GHD (2012) Victorian Aquifer Framework: updates for seamless mapping of aquifer surfaces. Report prepared for Department of Sustainability and Environment, May 2012. Viewed 16/01/2018, <http://www.vvg.org.au/cb_pages/files/207086.pdf>.

Gippsland Water (2012) Gippsland Water 2012 water supply demand strategy. Viewed 16/01/2018, <https://www.gippswater.com.au/application/files/3514/4902/4938/Water_Security_Outlook_-_December_2015.pdf>.

Goldie Divko LM (2015) A review of gas prospectivity: Gippsland region. Department of Economic Development, Jobs, Transport and Resources. Melbourne, Victoria.

GSV (Geological Survey Victoria) (2009) The polygons depict the outline of 3D surveys. These outlines illustrate the survey outlines but are not consistently defined. Viewed 11/08/2017, http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002766&extractionProviderId=1>.

GSV (Geological Survey Victoria) (2017a) Seismic Survey Lines - for Petroleum Industry Exploration. Viewed 1/08/2017, <https://www.data.vic.gov.au/data/dataset/seismic-survey-lines-for-petroleum-industry-exploration>.

GSV (Geological Survey Victoria) (2017b) Petroleum Wells (from Minerals and Petroleum's DbMap database) Viewed 11/08/2017, <http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002954&extractionProviderId=1>.

Hatton T, Otto C and Underschultz J (2004) Falling water levels in the Latrobe aquifer, Gippsland Basin: determination of cause and recommendations for future work. CSIRO Wealth from Oceans Flagship, Australia.

Hofmann H (2011) Understanding connectivity within groundwater systems and between groundwater and rivers. PhD Thesis, Monash University. Viewed 01 September 2014, http://www.groundwater.com.au/media/W1siZiIsIjIwMTMvMDcvMDkvMTdfNDJfNDBfMTEyX0hhcmFsZF9Ib2ZtYW5uX1BoRF9zbWFsbC5wZGYiXV0/Harald_Hofmann_PhD_small.pdf.

Lakes Oil (2017) Onshore Gippsland Basin Permits. Viewed 26/07/2017, <http://www.lakesoil.com.au/index.php/permits/onshore-gippsland-basin-vic>.

Nico C (2010) Report on transient groundwater flow modelling: West Gippsland CMA. Report for 'ecoMarkets' groundwater models, June 2010, prepared for Department of Sustainability and Environment.

Rahmanian VD, Moore PS, Mudge WJ and Spring DE (1990) Sequence stratigraphy and the habitat of hydrocarbons, Gippsland Basin. In: Brooks J (ed.), Classic Petroleum Provinces. Geological Society, London, Special Publications 50, 525–541.

Raymond OL, Gallagher R and Highet LM (2012) Surface geology of Australia, 1:2 500 00 scale, 2012 edition. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!b4088aa1-f875-2444-e044-00144fdd4fa6>.

Santos (2015) Information sheet: Orbost (Patricia Baleen) gas plant. Viewed 15/03/2017, <https://www.santos.com/media/3012/orbost-gas-plant-factsheet.pdf>.

Schaeffer J (2008) Scaling point based aquifer data for developing regional groundwater models: application to the Gippsland groundwater system. University of Melbourne.

Sinclair Knight Merz (2009) Hydrogeological mapping of southern Victoria. Report for Southern Rural Water. SKM, Melbourne.

Southern Rural Water (2012) Gippsland groundwater atlas. SRW, Victoria.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Victorian Government (2017) Media release March 2017. Viewed 16/01/2018, <http://www.premier.vic.gov.au/fracking-banned-in-victoria-giving-certainty-to-farmers/>.

VEWH (Victorian Environmental Water Holder) (2017) Seasonal Watering Plan 2017-18. Section 2: Gippsland Region. Victorian Government. Melbourne, Australia. Viewed 16/01/2018, <http://www.vewh.vic.gov.au/watering-program/seasonal-watering-plan>.

Woollands MA and Wong D (eds.) (2001) Petroleum Atlas of Victoria, Australia. Department of Natural Resources and Environment, Victoria.

Yates G, Doody T, Pritchard J, Walker K, Karim F, Carey H, Wallace L, Galinec V and Sundaram B (2015) Context statement for the Gippsland Basin bioregion. Product 1.1 from the Gippsland Basin Bioregional Assessment. Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia.

Walker G and Mollica F (1990) Review of the groundwater resources in the South East Region. Report No. 54 Water Resource Management Report Series, Melbourne, Victoria.

C.7 Isa Superbasin

Table C.47 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	Queensland, Northern Territory
Area	~56,150 km²
Max. basin depth/sediment thickness	~15,000 m
Age range	Paleoproterozoic–Mesoproterozoic
Depositional setting	Shallow to deep marine
Regional structure	Rift and post-rift sag sequences, N to NE trending faults
Overlying basins	South Nicholson, Georgina and Carpentaria basins
EXPLORATION STATUS	
Seismic lines	6,869 km 2D seismic
Number of wells	~13
Exploration status - conventional	Preliminary
Exploration status – shale/ tight gas	Early appraisal
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Undefined Proterozoic
Prospectivity	Moderate–high
Conventional discoveries	No commercial accumulations discovered to date
Hydrocarbon production – total to date	None to date (AERA, 2018)
2P Reserves	No reserves reported (AERA, 2018)
Remaining resources (reserves + contingent resources)	No remaining conventional resources reported; see shale/ tight gas resources 2C resources below (AERA, 2018)
Undiscovered resource estimates	No conventional prospective resources; see prospective shale/ tight gas resources below
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Shale gas
No. of wells targeting shale/tight gas plays	3
Production – shale/ tight gas	None
2P Reserves – shale/ tight gas	None reported
Remaining resources (reserves + contingent resources) – shale/ tight gas	0.15 Tcf shale gas (Table A.3; Armour Energy, 2014c; 2017; AERA, 2018)
Undiscovered resource estimates – shale/ tight gas	Best prospective shale resources of 22.1 Tcf in the Lawn Hill and Riversleigh Shale in permit ATP1087 (Table A.3; Armour Energy, 2017; see also AERA, 2018)
Hydrocarbon shows, tests – shale/ tight gas	Continuous gas flows occurred from the Lawn Hill Formation.

C.7.1 Basin Geology

The Isa Superbasin is located in the Western Fold Belt of the complex Mount Isa Province. The superbasin extends approximately 300 km from the eastern Leichhardt River Fault Trough through to the Murphy Tectonic Ridge; however its boundary remains very poorly defined and has not yet been incorporated into Geoscience Australia's Geological Provinces Database (Stewart et al., 2013; Figure C.52; Figure C.53).

The Isa Superbasin forms the youngest cover succession of the Lawn Hill Platform as defined by Blake (1987), and forms part of a network of similarly aged basins that evolved across the northern Australian craton during the Paleoproterozoic and Mesoproterozoic. The major stratigraphic units of the Isa Superbasin are the dominantly marine sediments of the McNamara Group (ca 1725–1590 ma) (Betts and Lister, 2001; Southgate et al., 2000, 2013) and the approximate distribution of these within the broader Mount Isa Province is shown in Figure C.53. Sequences in the upper part of the McNamara Group have been the focus for frontier conventional and unconventional gas exploration in the relatively undeformed northern part of the superbasin.

The McNamara Group is divided into lower and upper members. The lower member of the Group has a cumulative thickness of ~3000 m. It is dominantly composed of stromatolitic and dolomitic siltstone, sandstone and mudstone, deposited in a shallow water or shallow marine environment. The lower McNamara Group thins towards the western margin of the Mount Isa Rift, indicating the presence of an intrabasinal high along the western rift flank during the deposition of these formations. The sequences of the upper McNamara Group (Figure C.54) were deposited as the basin depocentre shifted to the northwest. These sequences have a cumulative thickness of ~8 km (Krassay et al., 2000).

The upper McNamara Group comprises (youngest to oldest); the Shady Bore Quartzite, Riversleigh Siltstone, Termite Range Formation, and Lawn Hill Formation. The Lawn Hill Formation comprises black shale, siltstones, tuff and minor sandstone. The Termite Range Formation comprises medium to coarse grained turbiditic sandstone and minor siltstone while the Riversleigh Siltstone contains moderate to deep water turbiditic shale, siltstone and minor sandstone (MBA, 2012). There is abundant evidence to suggest syndepositional fault activity occurred episodically during thermal subsidence (Andrews, 1998). Tuffaceous horizons throughout the upper McNamara Group indicate episodic volcanism.

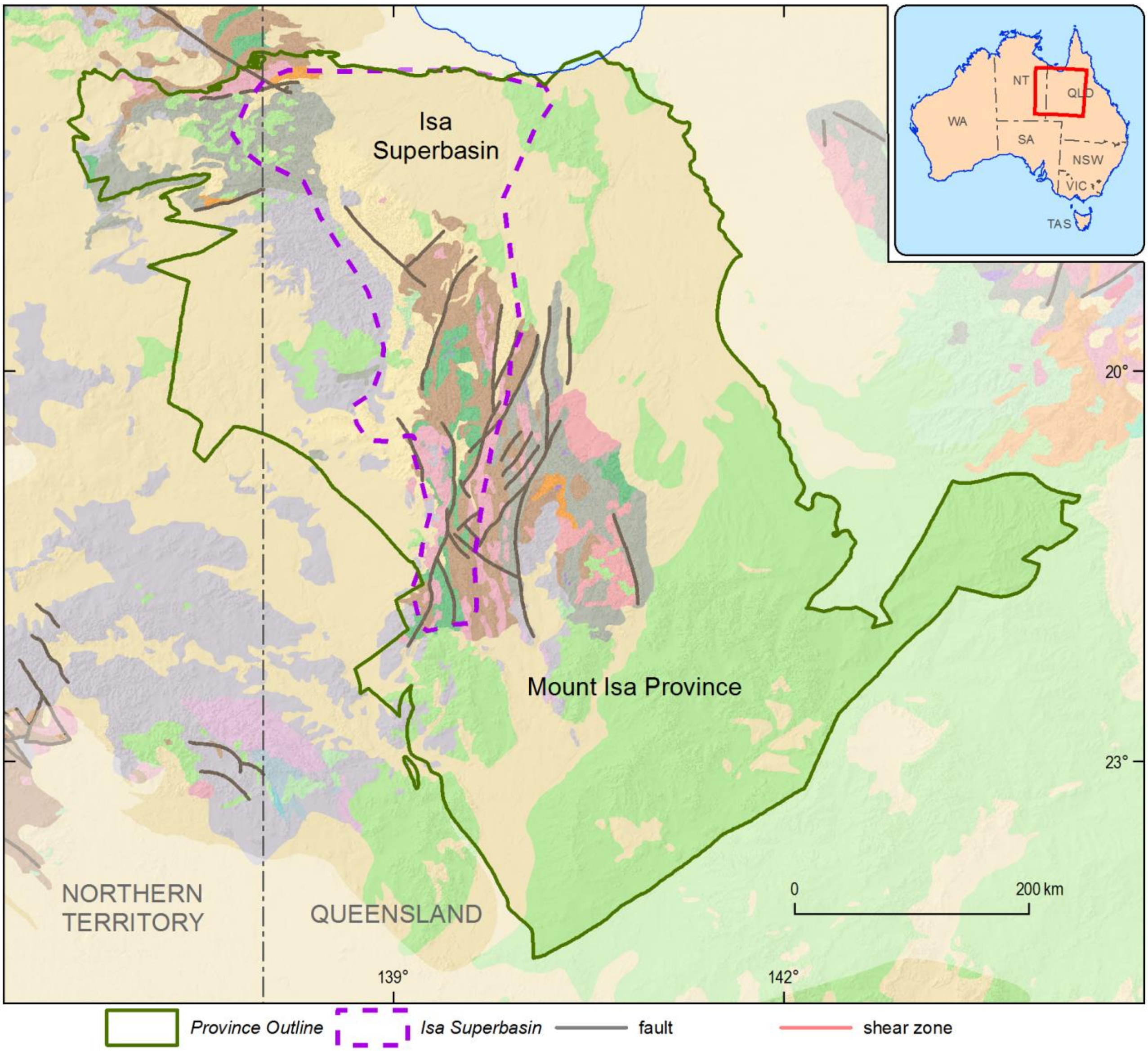

Figure C.52 Location of the Isa Superbasin within the Mount Isa Province on a base map of 1:2 500 000 scale surface geology (Raymond et al., 2012). Province outlines from Stewart et al. (2013). The Isa Superbasin outline remains poorly defined and the extent represented here is estimated from Betts and Lister (2001).

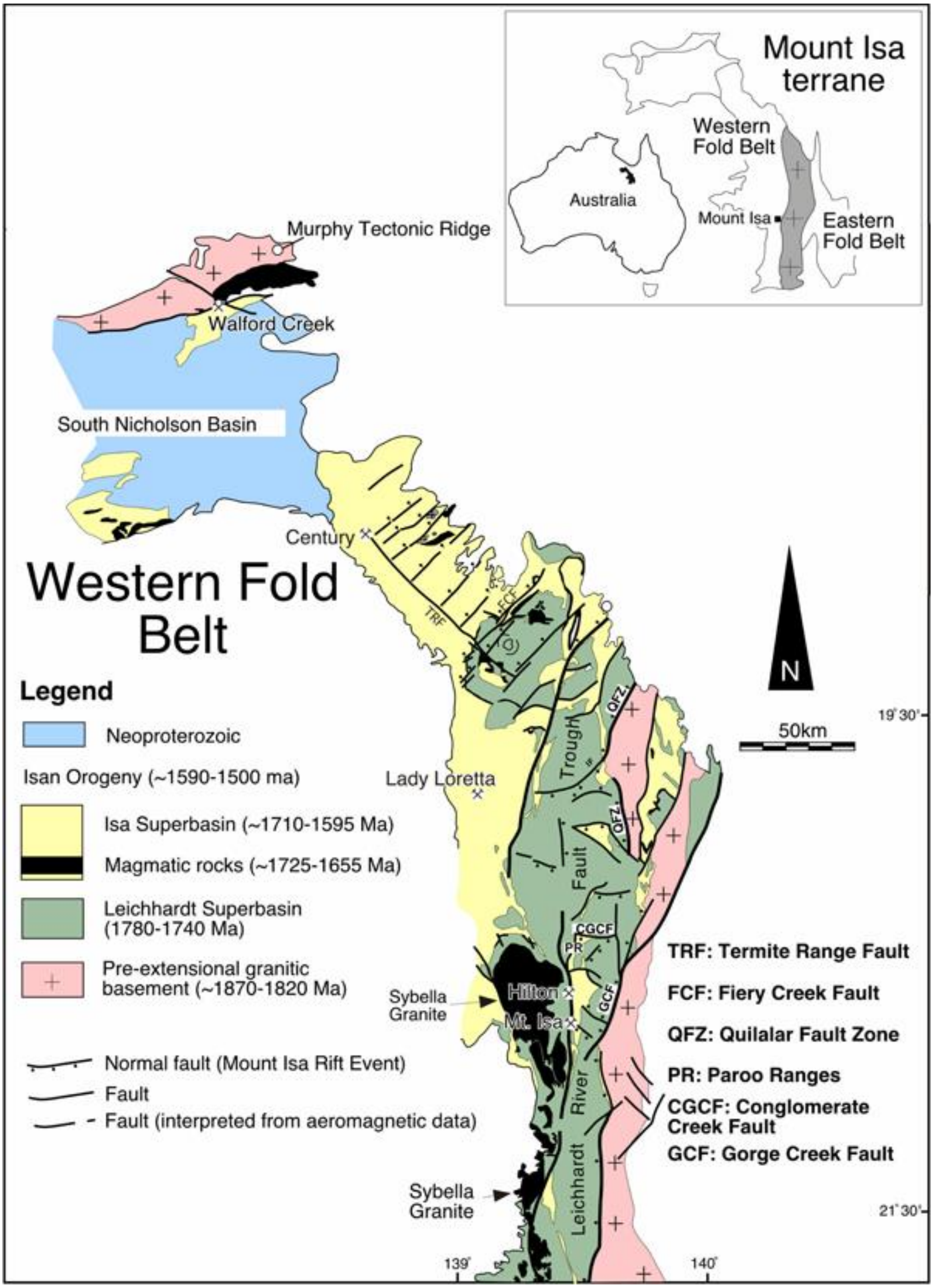

Figure C.53 Geological map of western Mount Isa Province highlighting the distribution of major structural elements, including the preserved areas of Isa Superbasin (modified from Betts and Lister, 2001).

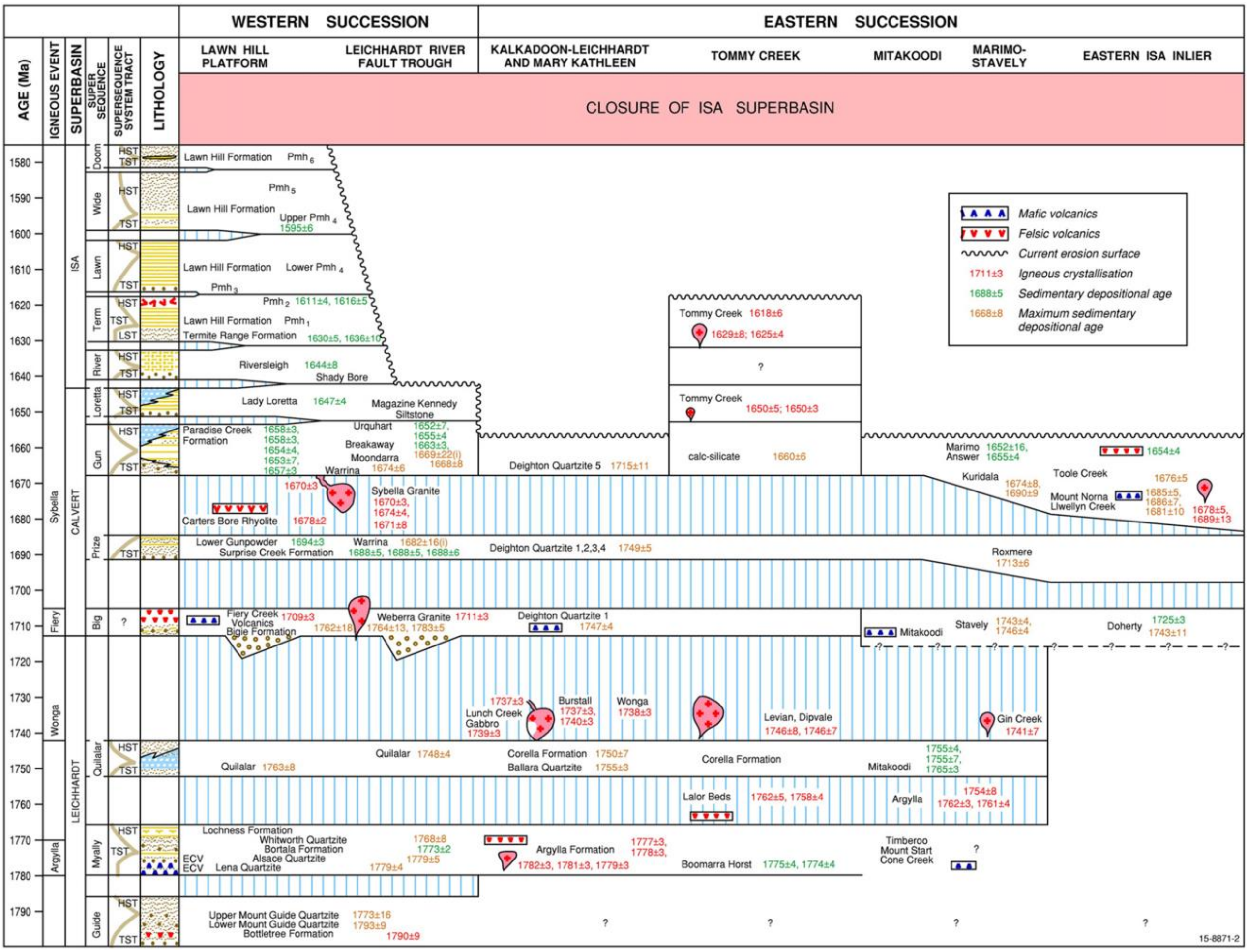

Figure C.54 Stratigraphy of the Mount Isa Province for the interval 1800 Ma to 1575 Ma (from Gibson et al., 2016 after Southgate et al., 2013).

C.7.2 Petroleum data coverage

The Isa Superbasin is poorly explored and has a sparse coverage of <7,000 km of 2D reflection seismic data of varying vintage and quality (Figure C.55; DNRME, b-d; NTGS, 2017b). About 13 petroleum and stratigraphic wells have been drilled in the Isa Superbasin (DNRME, 2017a; NTGS, 2017a). There is also complete coverage of gravity and airborne magnetics data across the superbasin of varying quality and data point spacing.

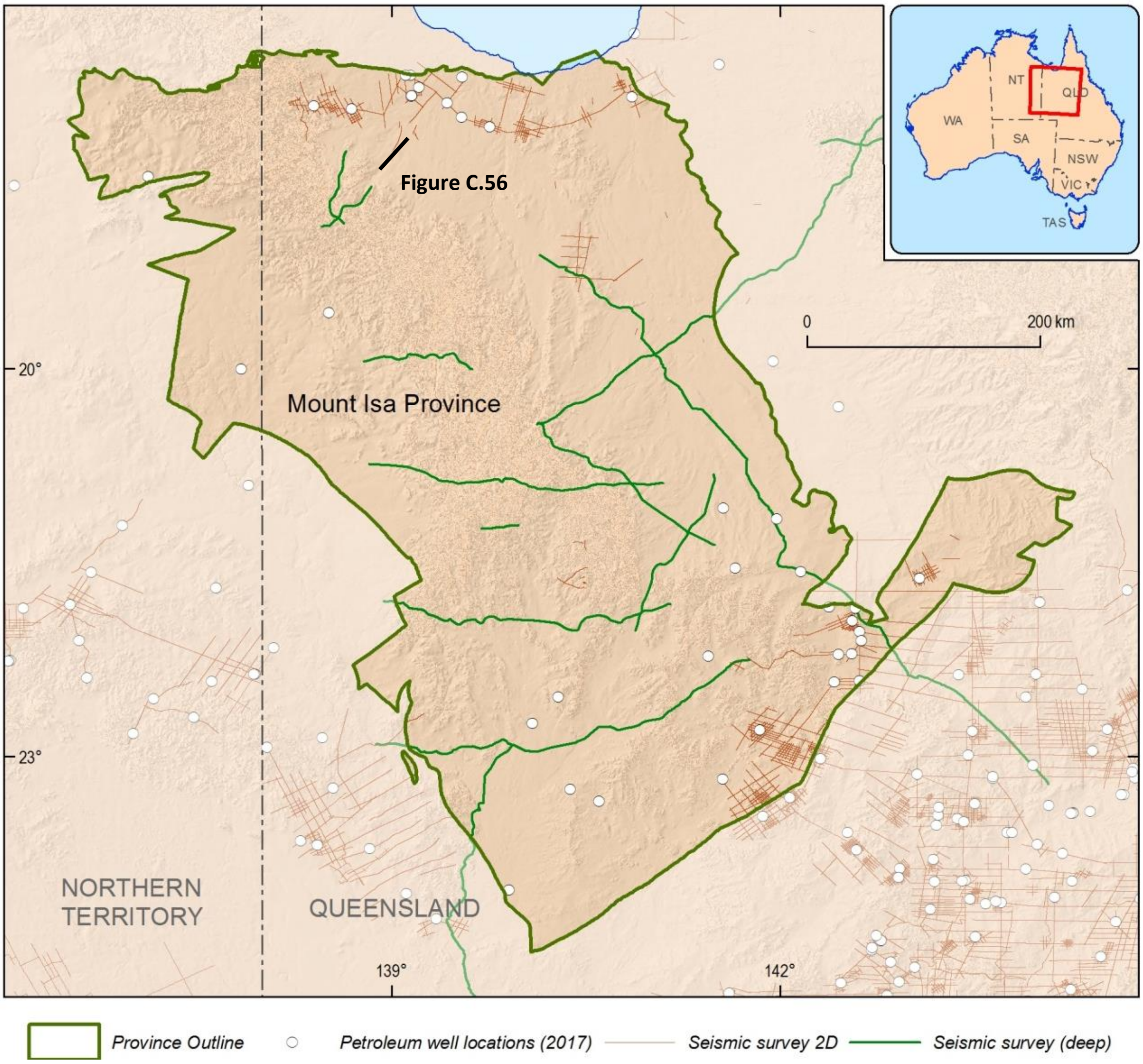

Figure C.55 Location of 2D seismic reflection lines, petroleum exploration wells and stratigraphic drill holes in the Mount Isa Province. Mount Isa Province outline from Stewart et al. (2013). Petroleum wells from NTGS (2017a) and DNRME (2017a). Seismic data from DNRME (b-d) and NTGS (2017b). Black line shows location of seismic line 89BN-6 in Figure C.56.

C.7.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Isa Superbasin is summarised in Table C.47.

Shale and tight gas exploration is still at a very early stage in the Isa Superbasin in Queensland. Several formations were identified as potential shale gas targets based on drilling undertaken in the 1980s and 1990s (McConachie et al., 1983). Armour Energy was granted ATP 1087 on the Lawn Hill Platform, and in 2013 drilled two vertical wells (Egilabria 2 and Egilabira 4) and one horizontal well (Egilabria 2 DW1) to evaluate the shale gas potential of the Lawn Hill Formation and Riversleigh Siltstone (Armour Energy, 2014a; Figure C.56). Egilabria 2 DW1 was the first lateral well in Australia to flow gas from a multi-stage, hydraulically stimulated shale formation (Figure C.56

and Figure C.57). In 2014, Armour Energy announced they have signed gas sale MOUs to mining operations in the area (de Weijer, 2015).

The Lawn Hill and Riversleigh formations have amongst the highest Total Organic Carbon (TOC) content of any shale play in Australia. A typical minimum TOC required for shale plays is 2%, whereas TOC values in world-class commercial shale plays, such as the Marcellus Shale in the USA, are in excess of 5%. Both the Lawn and Riversleigh shale formations show sweet spots with TOCs recorded up to 11% (Armour Energy, 2014b, 2017).

As a result of this exploration activity, Armour Energy reported the following resource estimates (Table C.47; Armour Energy, 2017):

- 2C resources relating to the Lawn Shale Formation in Egilabria 2 of 0.154 Tcf, and;
- best prospective shale gas resources of 22.1 Tcf for the Lawn Hill and Riversleigh Shale in permit ATP1087 (see also AERA, 2018).

Data for the key unconventional hydrocarbon targets are summarised in Table C.48.

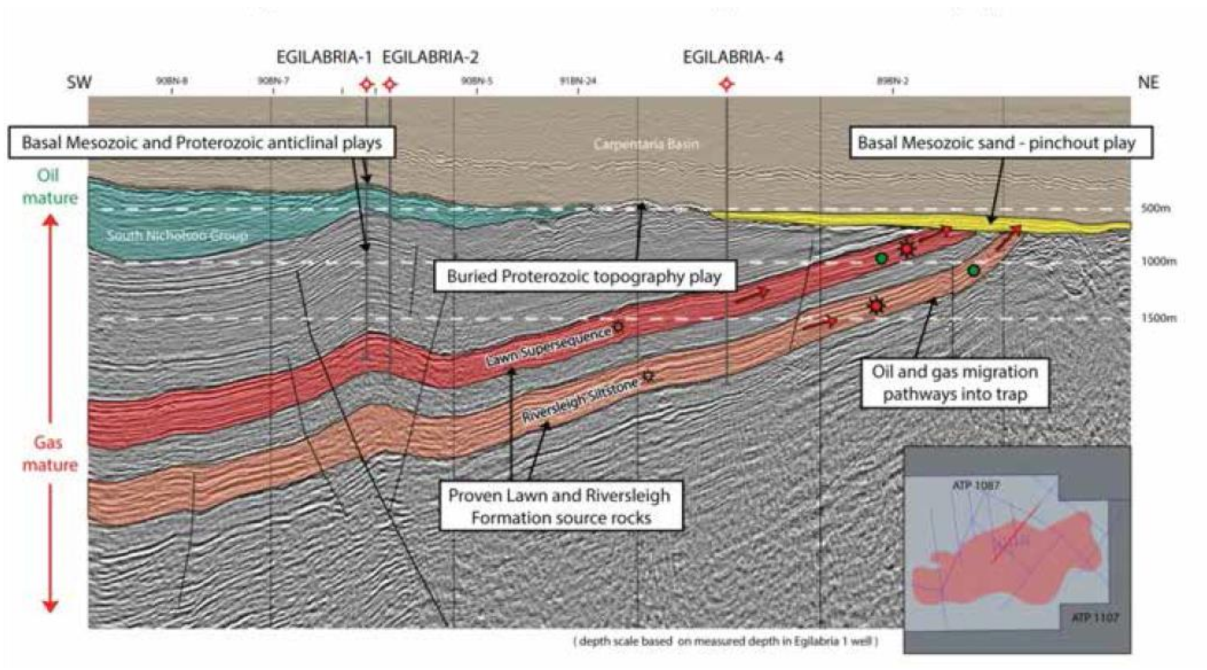

Figure C.56 Interpreted seismic section of line 89BN-6 showing the conventional and shale gas plays in the Isa Superbasin (modified from de Weijer, 2015). Location of the seismic line is shown in Figure C.55

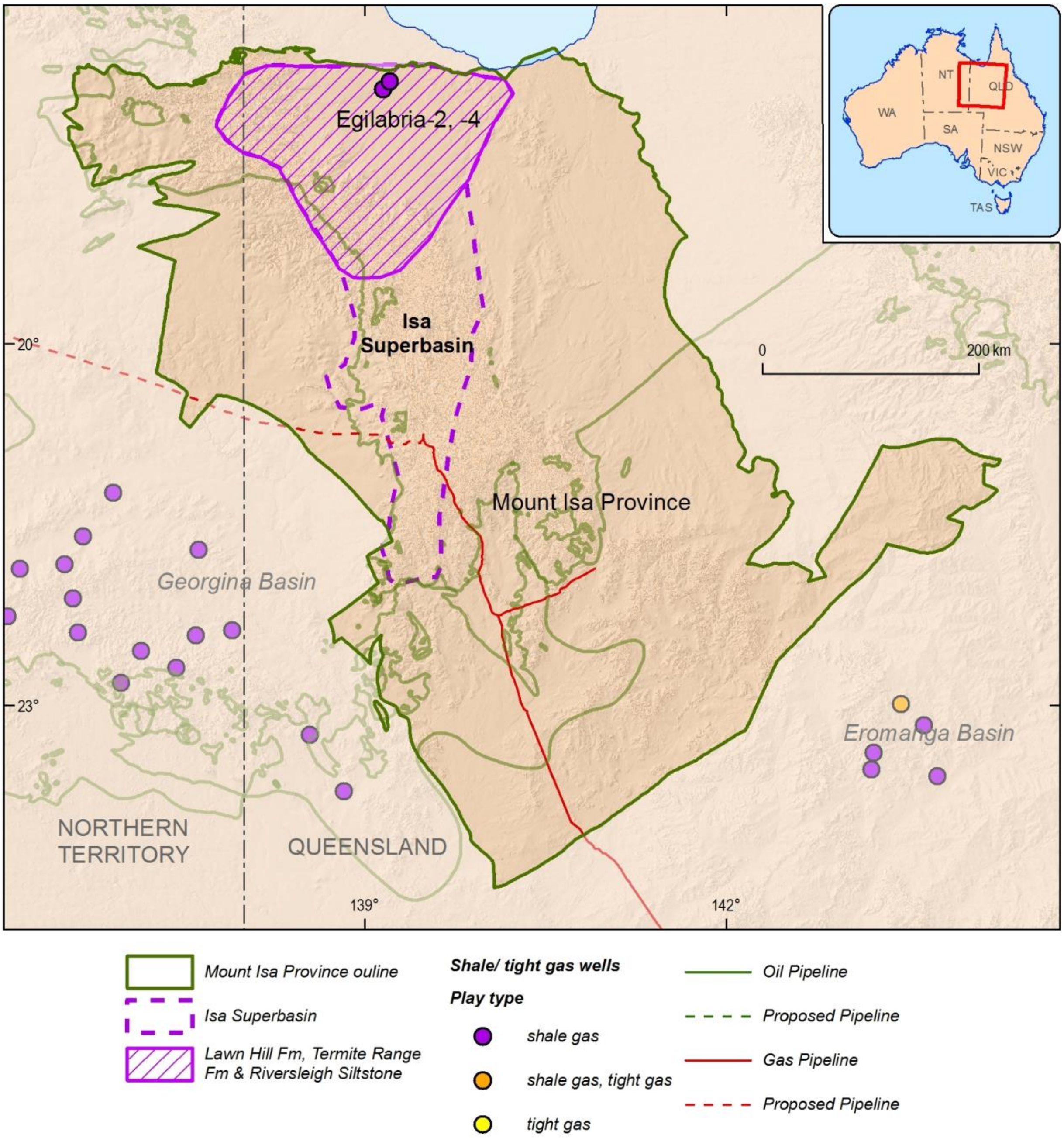

Figure C.57 Wells targeting shale gas plays and approximate play extents in the Isa Superbasin from DNRM (2017). The Isa Superbasin outline is derived from Betts and Lister (2001).

Table C.48 Summary of shale and tight gas plays (from DNRM, 2017).

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity	Play type	Exploration status
Lawn Hill Formation	Mesoproterozoic	Mid to outer shelf	Outcrop to 2,000 m	up to 2,200 m	Algal	up to 7%	Dry gas	Shale gas	Preliminary exploration
Riversleigh Siltstone	Paleoproterozoic-Mesoproterozoic	Mid to outer shelf	Outcrop to 4,500 m	up to 2,900 m	Algal	up to 8%	Dry gas	Shale gas	Preliminary exploration

C.7.4 Gas market access and infrastructure

The Isa Superbasin contains pipeline infrastructure linking the basin to the East Coast Gas Market. However, the pipeline brings gas into the region and the basin does not currently supply gas to the market (AER, 2017). The basin is poorly to moderately well serviced in terms of road and rail access, depending on location.

Figure C.58 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines, along with the distribution of major road and rail networks. Further details are summarised in Table C.49.

Table C.49 Summary of market access and infrastructure. Pipeline information from AER (2017) and Jemena (2017). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	East Coast Gas Market
Gas pipelines	Carpentaria Pipeline (Ballera to Mount Isa) – capacity 119 TJ/ Day
Gas processing facilities	None
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	>200 km
Road and rail access	Poorly to moderately well serviced
Approximate development timeframe	5–10 years

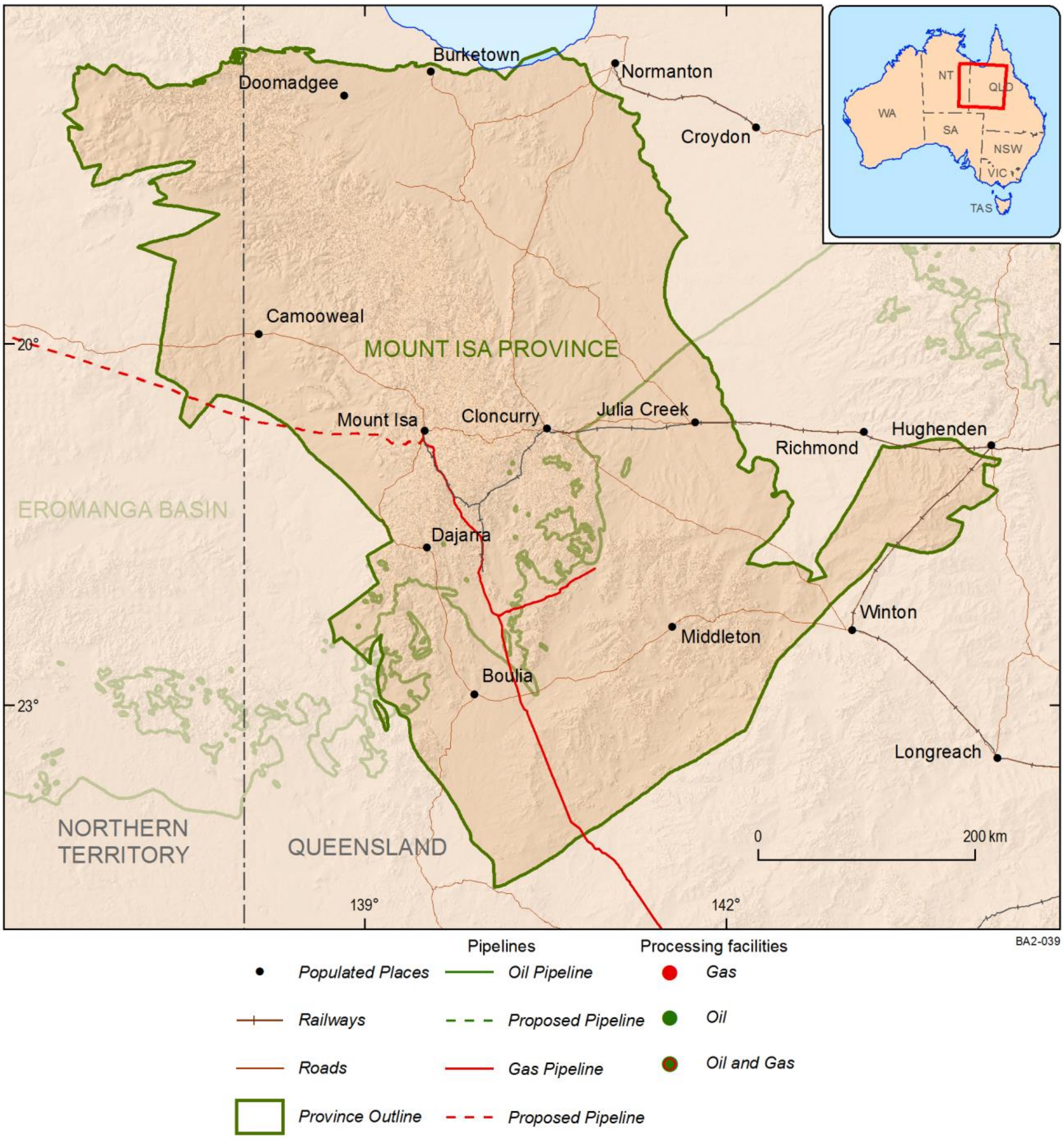

Figure C.58 Isa Superbasin infrastructure and pipelines. Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b).

C.7.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia.

There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland. In 2016, the Northern Territory Government implemented a moratorium on unconventional onshore gas activities in the territory, while an inquiry was undertaken and pending the Government's decision on the recommendations of the inquiry; the final report of the inquiry was released in March 2018 (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). Details of the moratorium and regulatory restrictions are described below.

C.7.5.1 Queensland

The Queensland Government has no identified constraints to tight and shale gas resource drilling or production stimulation. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.7.5.2 Northern Territory

In April 2018, the Northern Territory Government accepted all 135 recommendations of the inquiry and lifted the moratorium on hydraulic fracturing over 51% of the Territory. An implementation plan to be released in July 2018 will clearly show how the recommendations will be implemented.

C.7.6 Hydrogeology and groundwater

C.7.6.1 Groundwater systems

As the extent of the Isa Superbasin (Figure C.59) is not well defined, the following description of groundwater conditions relate to the *Mount Isa Province* as a whole.

The groundwater systems of the Mount Isa Province occur within the Paleoproterozoic to Mesoproterozoic rocks of the province itself, and the overlying younger basin successions (Figure C.59). The south eastern quadrant of the province is overlain by the Jurassic to Cretaceous sediments of the Eromanga Basin. To the northwest, the Jurassic to Cretaceous Carpentaria Basin is separated from the Eromanga Basin by the Euroka Arch; both the Eromanga and Carpentaria Basins contain major aquifers collectively known as the Great Artesian Basin (GAB). The western portion of the Mount Isa Province is overlain by the Neoproterozoic–Paleozoic Georgina Basin. Extensive and highly productive aquifers of the Georgina Basin include Cambrian–Ordovician carbonate units. The South Nicholson Basin underlies the Carpentaria and Georgina basins and overlies northern parts of the Mount Isa Province. Between the GAB in the east and Georgina Basin in the west, a central area of the Mount Isa Province has little to no overlying basins (Figure C.59).

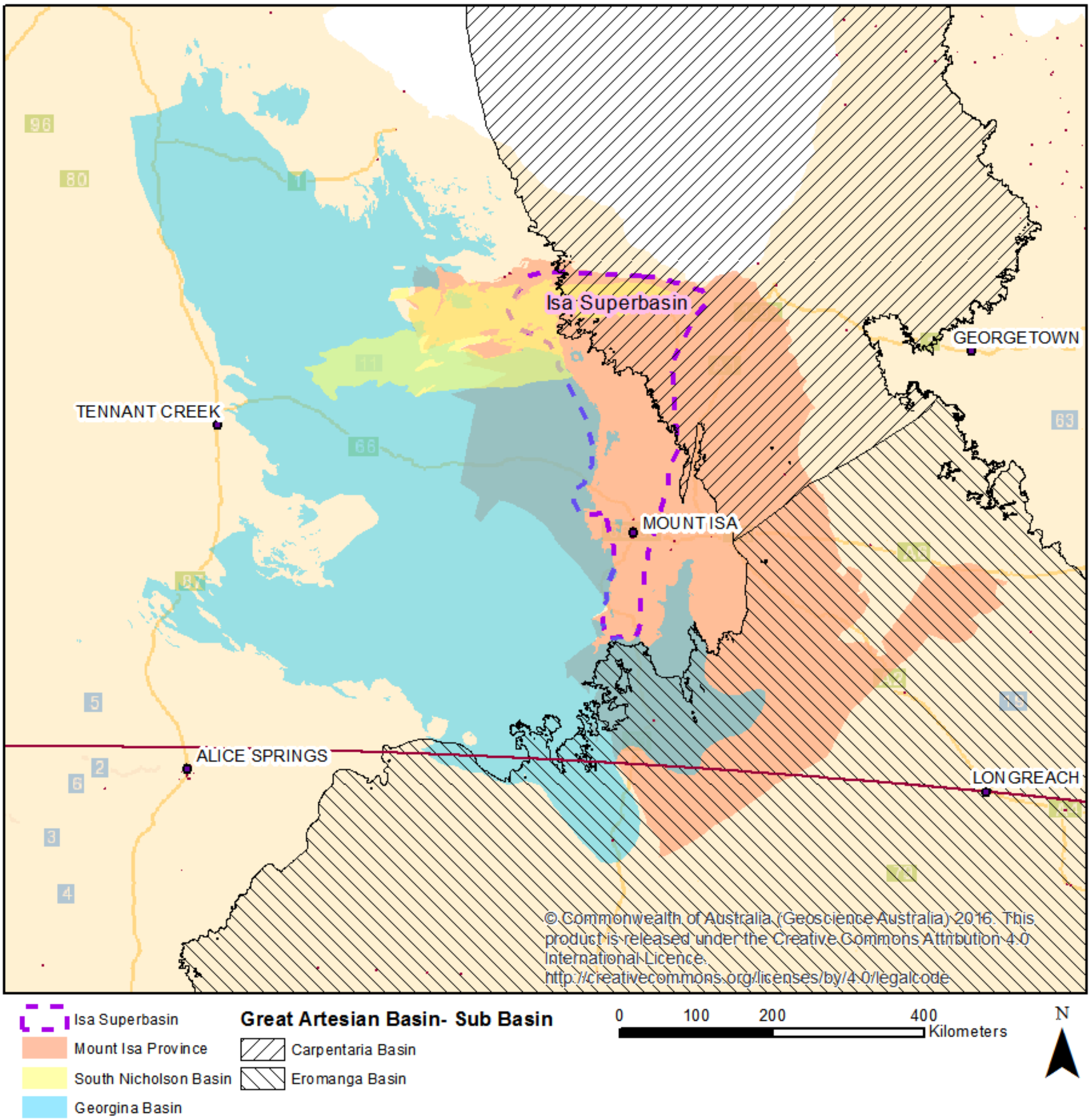

Figure C.59 Location of the Mount Isa Province and the overlying Eromanga, Carpentaria and Georgina Basins. Data from Geoscience Australia: Australian Geological Provinces (Stewart et al., 2013). The Isa Superbasin outline is derived from Betts and Lister (2001).

Eromanga and Carpentaria basins

The GAB within the Eromanga and Carpentaria basins consists of a complex series of aquifer and aquitard formations (See hydrostratigraphy in Figure C.60). Of note is the Lower Cretaceous Cadna-owie Formation aquifer and equivalents, which is one of the more widespread aquifers. Although the formation is generally a poor aquifer, there is commonly a thin upper sandstone member that is an excellent aquifer and is widely utilised by agriculture and industry. The structure of the GAB is such that the aquifer dips towards the east (the centre of the GAB). The Cadna-owie aquifer outcrops around the margins of the GAB, while the depth at the edge of the

Mount Isa Province ranges from 400–600 m. The thickness of the Cadna-owie aquifer is typically around 100 m over the Mount Isa Province (Ransley et al., 2015).

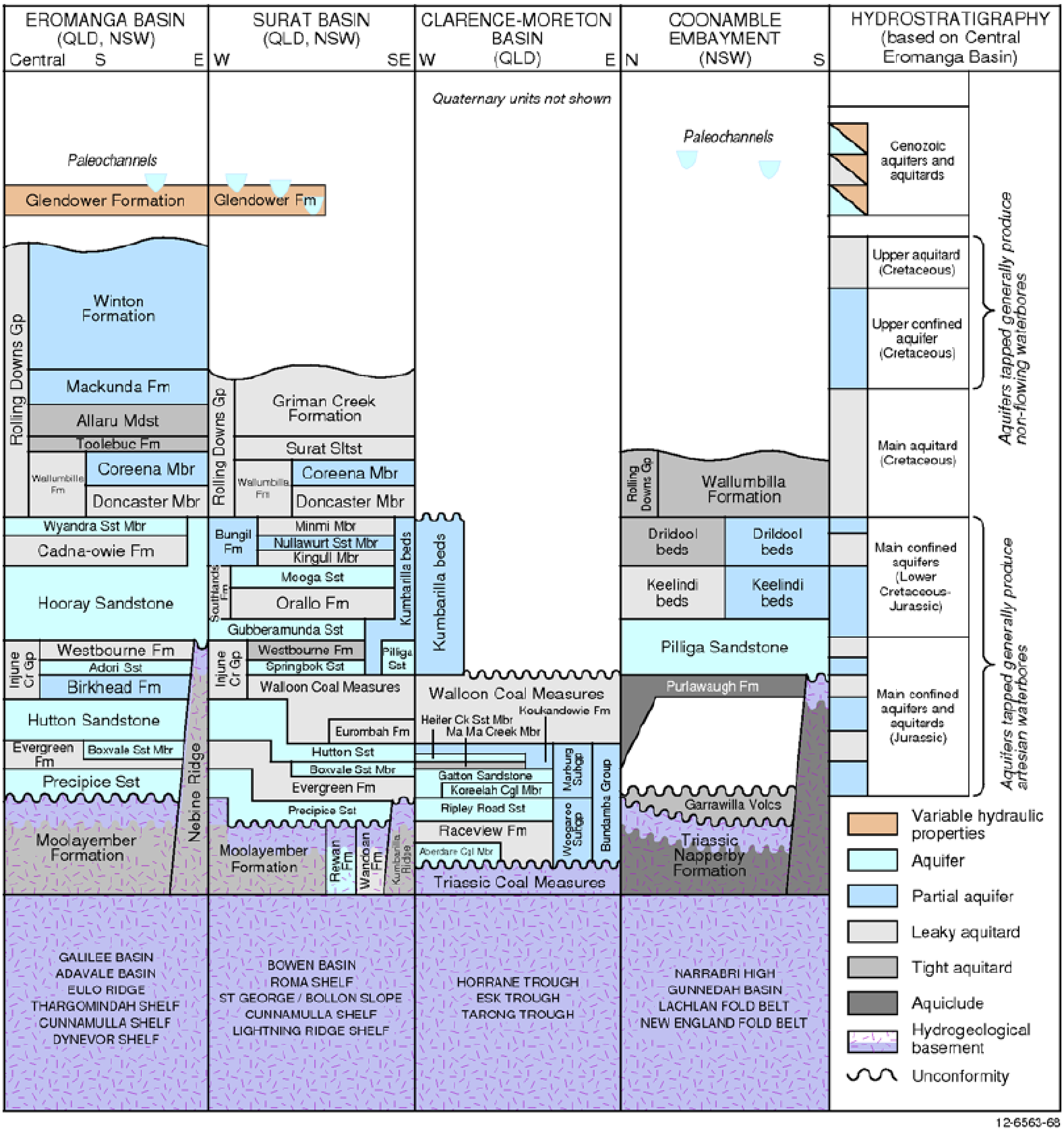

Figure C.60 Hydrostratrigraphy of the Eromanga Basin (adapted from Ransley et al., 2015).

At some locations, the GAB aquifers are potentially connected to aquifers within the underlying basins. In the Eromanga Basin for example, hydraulic connectivity between basins is evident over about 50% of the area where the Georgina Basin underlies the Eromanga Basin (Ransley et al., 2015; Ransley and Smerdon, 2012). In the southeastern Georgina Basin, there is evidence that groundwater from the GAB flows downwards into the Georgina Basin (Randal, 1978).

Mount Isa Province

The outcropping Mount Isa Province contains sedimentary rocks and volcanics, which have been tightly folded about northerly trending axes, extensively faulted, intruded by numerous granite plutons and mafic bodies and regionally metamorphosed to greenschist and amphibolite facies (Blake et al., 1984). While groundwater has been sourced from the metamorphic and igneous basement rocks in the Mt Isa-Cloncurry area, useful supplies have been difficult to obtain and there are many unsuccessful bores in the area. The intense folding and faulting has broken the continuity of potential aquifers and therefore the potential for useful aquifer systems may be diminished (Randal, 1978). As this area is located between the more productive aquifers of the Georgina Basin and GAB, the groundwater productivity of the Mount Isa Province is considered as low to moderate (Jacobson and Lau, 1987).

Georgina Basin

The primary water bearing units identified in the Georgina Basin are the Cambrian to Ordovician carbonate formations. Less significant sources are found in fractured rock aquifers and porous clastic rock aquifers. Regionally significant groundwater is occasionally sourced from overlying Cenozoic age sediments. The aquifer intermittently outcrops along the eastern margin of the basin, while depth to aquifer increases to over 200 m towards the centre of the basin (Randal, 1978). For more detail refer to the Georgina Basin Appendix (C.5).

South Nicholson Basin

The South Nicholson Basin unconformably underlies the Carpentaria Basin to the east and the Georgina Basin in the west. In these regions it is expected that the primary groundwater source would be the typically productive Jurassic to middle Cretaceous GAB aquifers of the Carpentaria Basin and the Cambrian to Ordovician carbonate formations in the Georgina Basin.

C.7.6.2 Groundwater quality

Groundwater quality as indicated by Total Dissolved Solids (TDS) is highly variable across the Mount Isa Province. TDS values in the Cadna-owie aquifer typically range from 600–900 mg/L on the western margin of the GAB and 900–1200 mg/L on the southern margin (Ransley et al., 2015).

In the Georgina Basin, salinity levels are generally low in the middle Cambrian limestones and are generally lower than the non-carbonate aquifers, with average concentrations ranging from 390 mg/L to 962 mg/L TDS in the Cambrian limestones (Smith, 1972). Regions of significantly higher salinity (TDS <5000 mg/L) occur in sequences containing evaporite beds (Verma and Jolly, 1992).

C.7.6.3 Groundwater flow

Within the portion of the GAB overlying the Mount Isa Province, groundwater flow direction is typically in a north-easterly to northerly direction in the Carpentaria Basin and southerly to south-easterly in the Eromanga Basin, away from the recharge area along the western margins (Figure C.61).

In the central portion of the Mount Isa Province, groundwater flow directions are likely to be influenced by factors such as topography, proximity to rivers and abstraction due to the local nature of the aquifer systems.

In the southeastern Georgina Basin, groundwater flow is typically towards the townships of Camooweal and Urandagi and then southerly direction, as is evident from the regional potentiometric contours (Randal, 1978) (Figure C.62).

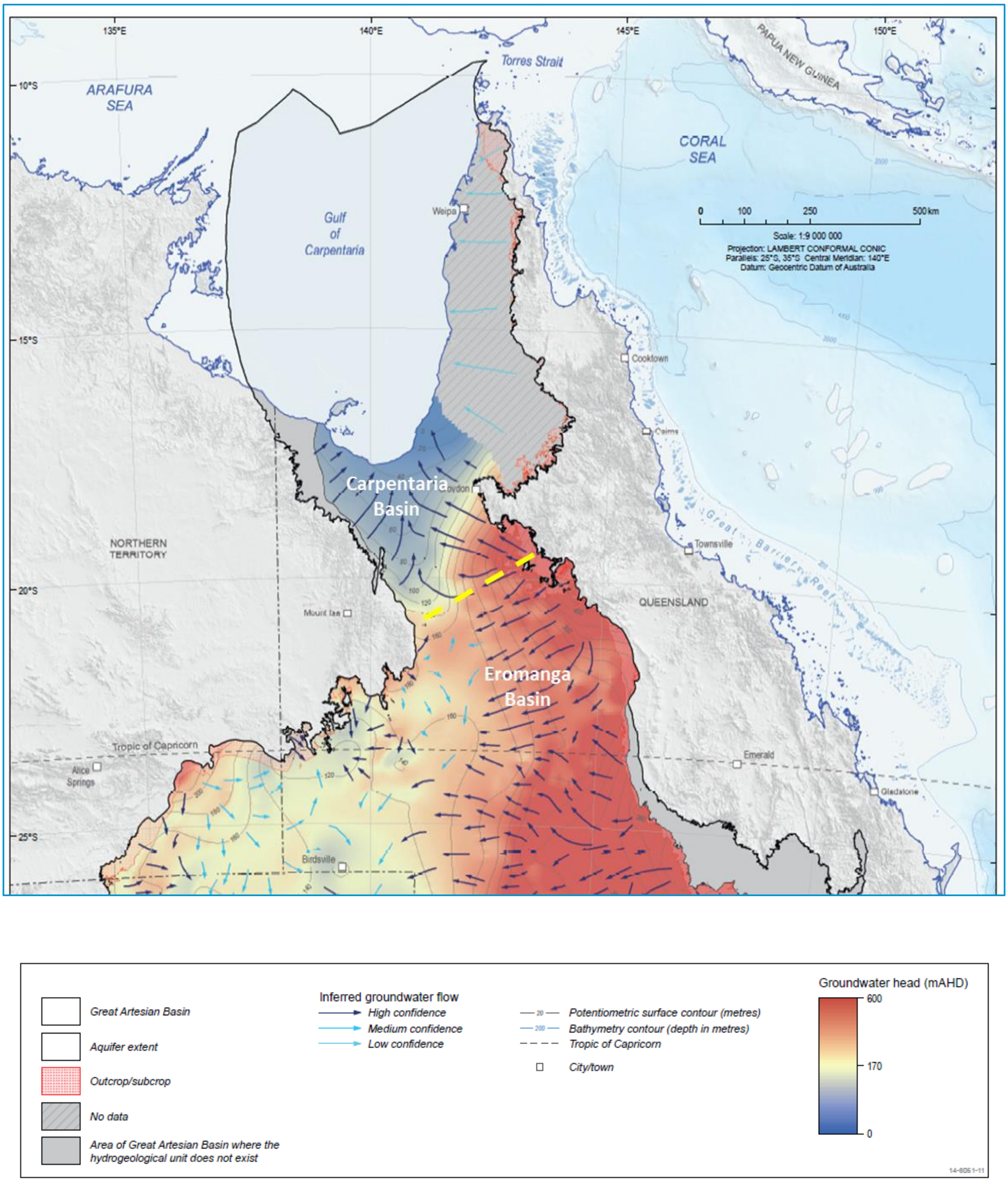

Figure C.61 Groundwater flow in the Great Artesian Basin (adapted from Ransley et. al., 2015).

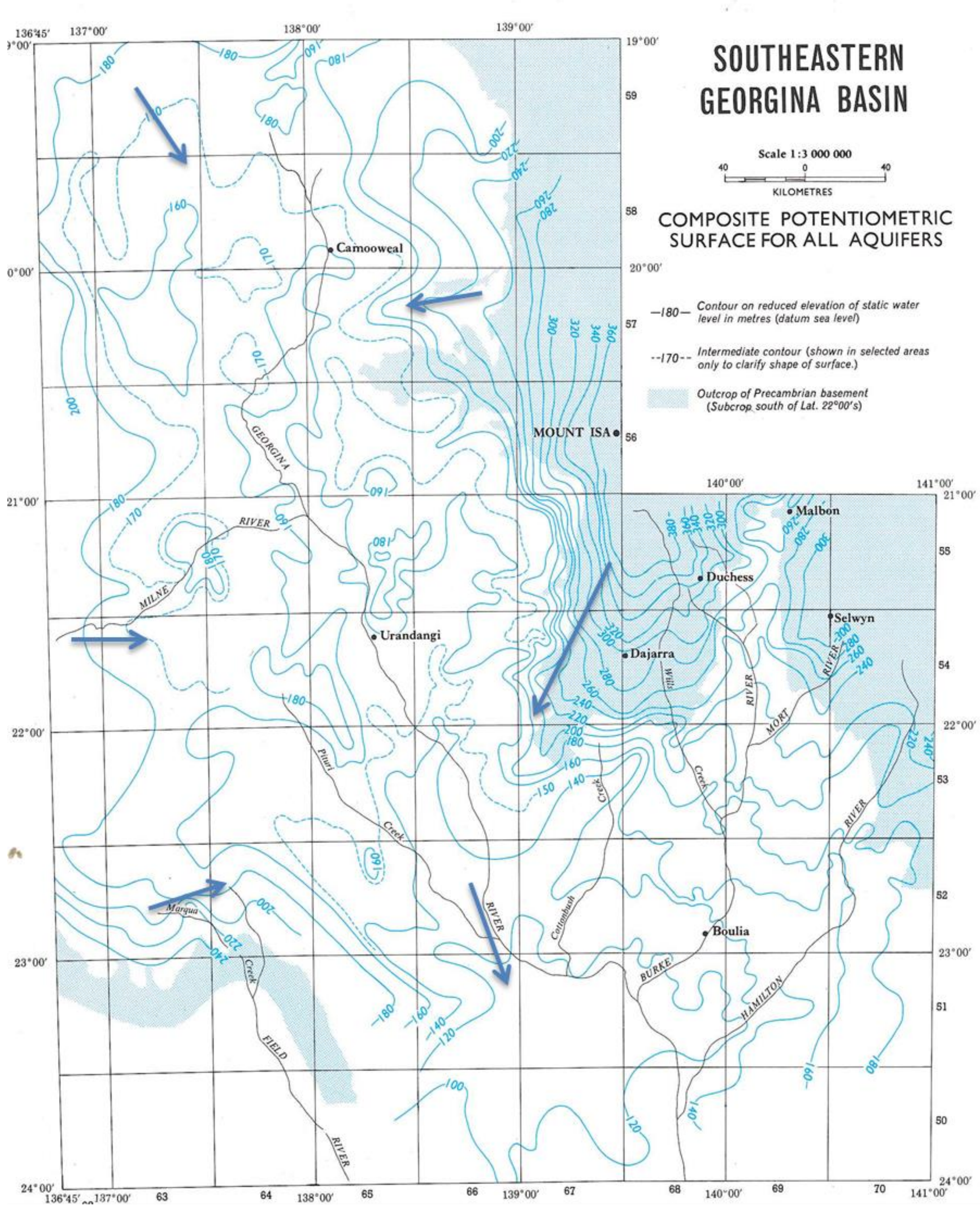

Figure C.62 Composite potentiometric surface for all aquifers in the in the southeastern Georgina Basin (adapted from Randal, 1978)

C.7.6.4 Groundwater planning and use

Average groundwater bore density across the Mount Isa Province was 0.016 registered bores per km^2 according to the NGIS (BoM, 2016) database, with notable higher density around Mt Isa, Cloncurry and townships along the Stuart Highway.

Groundwater management plans are in place for all regions of the Queensland portion of the Mount Isa Province, with the exception of the central portion around Mt Isa. The relevant plans for the Queensland portion of the Mount Isa Province are the: Water Plan (Great Artesian Basin) 2006, Water Plan (Georgina and Diamantina) 2004, and Water Plan (Gulf) 2007 (Queensland Government 2006, 2004, 2007)

Table C.50 presents information from the NGIS (BoM, 2016) and shows summary information of the registered bores within the extent of the Mount Isa Province.

Table C.50 Summary statistics for groundwater bores and water use in the Mount Isa Province region

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	6,009 (0.02)	
Purposes of registered bores (Top 5, number)	Unknown	4,321
	Stock	1,560
	Domestic Household	657
	Community water supply	64
	Industrial	41
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 24 Median: 79 90th Percentile: 426	

C.7.7 Surface water hydrology

C.7.7.1 Surface water systems

According the BoM Geofabric, the majority of Mount Isa Province is covered by the Nicholson–Leichhardt, Flinders–Norman, Morning Inlet, Victoria River–Wiso, Cooper Creek–Bulloo River, Settlement Creek and Diamantina–Georgina river catchments (BoM, 2014). These river basins are presented in Figure B.18

A number of significant population centres rely on surface water for domestic and industrial supply. These include Mt Isa sourcing water from Lake Moondarra and Lake Julius, and Cloncurry sourcing water from Chinaman Weir on the Cloncurry River.

C.7.7.2 Surface water quality

Average surface water salinity reported by the BoM (2017a) for the Gregory River and Gunpowder Creek (Nicholson-Leichhardt Catchment) was between 0–500 mg/L (fresh) and 500–1,000 mg/L (fresh to marginal) respectively for 2015–2016.

Surface water quality for the Victoria River as indicated by electrical conductivity, was generally around 200–400 µS/cm (Kirby and Faulks, 2004). In the Roper River, electrical conductivity levels range from 834 to 1873 µS/cm (Faulks, 2001).

A survey of selected surface water bodies in the southeastern Georgina Basin by Randal (1978) showed the water suitable for stock purposes, with the exception of a sample taken at Young Australia Mine. It was noted that although most samples were suitable for domestic use, water colour was milky, due to clay suspension.

C.7.7.3 Surface water flow

Rainfall in the region is markedly seasonal, with the majority of the rainfall occurring under the influence of the northwest monsoon, usually between late December and late February. Average rainfall varies from around 600–1,000 mm in the north to 200–300 mm in the south (BoM, 2017b).

Generally rivers are ephemeral and flow following the monsoonal rains. Permanent waterholes are present in many of the river systems. The predominantly perennial Roper River has marked seasonal flow regime of high water levels during the wet season and decreased water flow and river stage towards the end of the dry season. Approximately 96% of rainfall and 92% of runoff occurs during the wet season months according to the historical and recent climatic record (CSIRO, 2009).

Regional Water Information (BoM, 2017b) provides information on the Gregory River system, which drains into the Gulf of Carpentaria. The stated average flow for the Gregory River at Gregory Downs), located approximately 120 km from the Gulf of Carpentaria is 1794 ML/day.

C.7.7.4 Surface water planning and use

The Water Resource (Georgina and Diamantina) Plan 2004 (Queensland Government, 2004) allocates 1,000 ML as general reserve in the Lower Diamantina management area, and another 1,500 ML is available across the whole Diamantina-Georgina catchment area for projects of state significance. However, there is negligible use of surface water in the region, as most are reliant on bore water for a dependable water supply (Smith et al., 2015).

C.7.8 Groundwater – surface water interactions

Within the central Eromanga region and the broader GAB, groundwater recharge occurs through rainfall infiltration on the western slopes of the Great Dividing Range. Recharge predominantly occurs in the high rainfall areas of the eastern GAB and flows in a west to southwest direction (DWE, 2009). To a lesser degree, recharge occurs in the southeast of the Northern Territory, and the western margin of the Eromanga Basin in South Australia (SAALNRMB, 2009).

Groundwater recharge to the Paleozoic and Cenozoic aquifers in the Georgina Basin is generally by direct percolation of rainfall into surface fractures, permeable soil cover and through alluvial or lacustrine recharge (Randal, 1978).

Many ecosystems depend on groundwater from springs in the GAB. These range in size from small vents to large mounds and may be surrounded by wetlands. Spring complexes that are located in major regional clusters are referred to as supergroups. The Flinders River and Springvale supergroups, which occur in the northern and northwestern portion of the central Eromanga Basin respectively, include complexes overlying the Mount Isa Province (Smerdon et al., 2012)

C.7.9 Environmental assets

Within the Mount Isa Province, there are 6,323 km^2 of Listed Nationally Important Wetlands, 37,734 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential) and no Ramsar wetlands. A total of 10,111 km^2 of protected areas (such as national parks) are listed (Table C.51).

Table C.51 Summary statistics for environmental assets

Environmental Assets		
Ramsar Wetlands	None	
Nationally Important Wetlands Top 5 by area (area km^2)	Thorntonia Aggregation	2,970
	Southern Gulf Aggregation	2,140
	Musselbrook Creek Aggregation	451
	Nicholson Delta Aggregation	357
	Gregory River	265
	TOTAL WETLAND AREA	6,323
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	National Park	6,745
	Nature Refuge	2,298
	Regional Park	968
	—	0
	—	0
	TOTAL PROTECTED AREA	10,011
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	37,734	

C.7.10 Social considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists are presented in the table below (Table C.52).

Table C.52 Summary statistics for social and general characteristics

GENERAL CHARACTERISTICS		
Population	25,000	
Major population centres (two)	Mt Isa, Cloncurry	
Land use types Top 5 by area (area km²)	Grazing native vegetation	261,353
	Other Protected areas	9,058
	Nature Conservation	6,924
	Water	1,602
	Minimal use	200
Aboriginal Protected Area (CAPAD 2016) and Native title (area km²)	116,360	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

ANZECC (1992) Australian water quality guidelines for fresh and marine waters. National Water Quality Management Strategy Paper No 4, Australian and New Zealand Environment and Conservation Council, Canberra.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

Andrews SJ (1998) Stratigraphy and depositional setting of the upper McNamara Group, Lawn Hill Region, Northwest Queensland. Economic Geology 93, 1132–1152.

Armour Energy (2014a) Egilabria 4 Reaches Total Depth With Multiple Gas Shows and Egilabria 2 Update – Cleanup Continuing Ahead of Production Test. ASX Announcement. Viewed 07/08/2017, <https://wcsecure.weblink.com.au/pdf/AJQ/01446411.pdf>.

Armour Energy (2014b) Armour Energy Limited annual report. Viewed 07/08/2017, <https://wcsecure.weblink.com.au/pdf/AJQ/01564041.pdf>.

Armour Energy (2014c) Third part independent certification of 350 PJs (3C) contingent resources Lawn Hill Shale, Egilabria 2 DW1, ATP1087, Queensland. Viewed 07/08/2017, <http://www.armourenergy.com.au/assets/2014/2014.07.16%20-%20ASX%20Announcement%20Maiden%20Contingence%20Resource%20Lawn%20Hill20Shale20Egilabria20220DW1.pdf>

Armour Energy (2015) 66% increase in prospective gas resources in Northern Australia. Maiden prospective gas resources in the Tawallah Group, McArthur Basin (NT) and in the Riversleigh Shale Formation (QLD). Viewed 07/08/2017, <http://www.armourenergy.com.au/assets/1475615.pdf>.

Armour Energy (2017) Queensland. Viewed 16/01/2018, <https://www.armourenergy.com.au/north-west-queensland>.

Betts PG and Lister GS (2001) Comparison of the ‘strike-slip’ versus the ‘episodic rift-sag’ models for the origin of the Isa Superbasin, Australian Journal of Earth Sciences, 48(2), 265–280.

Blake DH (1987) Geology of the Mount Isa Inlier and environs, Queensland and Northern Territory. Bureau of Mineral Resources, Australia, Bulletin 225.

Blake DH, Bultitude RJ, Donchak PJT, Wyborn LAI, Hone IG (1984) Geology of the Duchess-Urandangi region, Mount Isa Inlier, Queensland. Department of Resources and Energy, QLD.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

BoM (Bureau of Meteorology) (2017a) Average annual Australian Rainfall 1961-1990. Viewed 03/08/2017, <http://www.bom.gov.au/jsp/ncc/climate_averages/rainfall/index.jsp>.

BoM (Bureau of Meteorology) (2017b) Regional Water Information. Viewed 01/08/2017, <http://www.bom.gov.au/water/rwi/#wq_ssme/001/2016>

CAPAD (2016) Collaborative Australian Protected Area Database, 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

CSIRO (2009) Water in the Roper region. In: CSIRO (2009) Water in the Gulf of Carpentaria Drainage Division. A report to the Australian Government from the CSIRO Northern Australia Sustainable Yields Project. CSIRO Water for a Healthy Country Flagship, Australia. 59-120

de Weijer R (2015) Armour Energy, preparing for the next wave of investment in oil and gas exploration. UGAS -Unconventional Gas Conference Brisbane 2015. Viewed 16/01/2018, <https://wcsecure.weblink.com.au/pdf/AJQ/01616806.pdf>.

DNRM (Department of Natural Resources and Mines) (2017) Queensland's unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DWE (NSW Department of Water and Energy) (2009) Water Sharing Plan NSW Great Artesian Province Groundwater Sources: background document. NSW Department of Water and Energy, Sydney.

Faulks JJ (2001) Roper River Catchment- An assessment of the physical and ecological condition of the roper river and its major tributaries. Technical Report No. 36/2001. Northern Territory Government.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Gibson GM, Meixner AJ, Withnall IW, Korsch RJ, Huttonc LJ, Jones LEA, Holzschuh J, Costelloe RD, Henson PA and Saygin E. (2016) Basin architecture and evolution in the Mount Isa mineral province, northern Australia: Constraints from deep seismic reflection profiling and implications for ore genesis Ore Geology Reviews 76, 414–441.

Jacobson G and Lau JE (1987) Hydrogeology of Australia, Geoscience Australia. Viewed 10/07/2017, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7892-72bf-7506-e044-00144fdd4fa6>.

Jemena (2017) Northern gas pipeline. Viewed 16/01/2018, <http://jemena.com.au/industry/pipelines/northern-gas-pipeline>.

Kirby SL and Faulks JJ (2004) An assessment of the physical and ecological conditions of the Victoria River and its Major Tributaries. Technical Report 40/2004K, Northern Territory Government.

Krassay AA, Bradshaw BE, Domagala J and Jackson MJ (2000) Siliciclastic shoreline to growth-faulted, turbiditic sub-basins: The Proterozoic River Supersequence of the upper McNamara Group on the Lawn Hill Platform, northern Australia. Australian Journal of Earth Sciences 47(3), 533-562.

MBA (2012) Independent Expert's Report for Armour Energy Limited.

McConachie BA, Barlow MG, Dunster JN, Meaney RA and Shaap AD (1993) The Mount Isa Basin – Definition, structure and petroleum geology. APEA Journal, 33(1), 237–257.

NTGS (Northern Territory Geological Survey) (2017a) Geoscience exploration and mining information system (GEMIS) – Petroleum wells. Viewed 11/08/2017, <http://www.geoscience.nt.gov.au/gemis/ntgsjspui/handle/1/79187>.

NTGS (Northern Territory Geological Survey) (2017b) Northern Territory Statewide Geophysics – Seismic Lines. Viewed 11/08/2017, <http://www.ntlis.nt.gov.au/metadata/export_data?type=html&metadata_id=FB25348A02CB16B2E040CD9B2144584B>.

Queensland Government (2004) "Water Resource (Georgina and Diamantina) Plan 2004", legislation under the Water Act 2000, current as at 27 June 2014. Viewed 13/09/2017, <https://www.legislation.qld.gov.au/view/pdf/inforce/2014-06-27/sl-2004-0152>.

Queensland Government (2006) "Water Plan (Great Artesian Basin) 2006", legislation under the Water Act 2000 (Qld), current as at 3 July 2017. Viewed 04/08/2017, https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf>.

Queensland Government (2007) "Water Plan (Gulf) 2007", legislation under the Water Act 2000 (Qld), current as at 2 September 2017. Viewed 29/09/2017, <https://www.legislation.qld.gov.au/view/pdf/2017-09-02/sl-2007-0268>.

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 22/01/2018, <https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells>.

Randal MA (1978) Hydrogeology of the southeastern Georgina Province and environs, Queensland and Northern Territory. Queensland Department of Mines. Publication 366, April 1978.

Ransley TR, Radke BM, Feitz AJ, Kellett JR, Owens R, Bell J, Stewart G and Carey H (2015) Hydrogeological Atlas of the Great Artesian Basin, Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/9781925124668>.

Ransley TR and Smerdon BD (eds) (2012) Hydrostratigraphy, hydrogeology and system conceptualisation of the Great Artesian Basin. A technical report to the Australian Government from the CSIRO Great Artesian Basin Water Resource Assessment. CSIRO Water for a Healthy Country Flagship, Australia.

Raymond OL, Gallagher R and Highet LM (2012) Surface geology of Australia, 1:2 500 00 scale, 2012 edition. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!b4088aa1-f875-2444-e044-00144fdd4fa6>.

SAALNRMB (South Australian Arid Lands Natural Resource Management Board) (2009) Explanation of the Water Allocation Plan for the Far North Prescribed Wells Area. South Australian Arid Lands Natural Resources Management Board, South Australia.

Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Final Report, March 2018. Viewed 23/04/2018, <https://frackinginquiry.nt.gov.au/inquiry-reports?a=494286>.

Smerdon BD, Marston FM and Ransley TR (2012) Water Resource Assessment for the Central Eromanga Region. CSIRO, Commonwealth of Australia.

Smith KG (1972) Stratigraphy of the Georgina Province. Bureau of Mineral Resources, Geology and Geophysics, Canberra.

Smith M, Karim F, Sparrow A, Cassel R and Hall L (2015) Context statement for the Cooper subregion. Product 1.1 for the Cooper subregion from the Lake Eyre Basin Bioregional Assessment. Bioregional Assessment Programme, Department of the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia, Australia. Viewed 16/01/2018, <http://data.bioregionalassessments.gov.au/doc/BA-LEB-COO-110-ContextStatement-20150903.pdf>.

Southgate PN, Bradshaw BE, Domagala J, Jackson MJ, Idnurm M, Krassay AA, Page RS, Sami TT, Scott DL, Lindsay JF, McConachie BA and Tarlowski C (2000) Chronostratigraphic basin framework for Palaeoproterozoic rocks (1730–1575 Ma) in northern Australia and implications for mineralisation. Australian Journal of Earth Sciences, 47, 461–85.

Southgate PN, Neumann NL and Gibson GM (2013) Depositional systems in the Mt Isa Inlier from 1800 Ma to 1640 Ma: implications for Zn–Pb–Ag mineralisation. Aust. J. Earth Sci. 60, 157–173.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Verma MN and Jolly PB (1992) Hydrogeology of Helen Springs; Explanatory notes for the 1:250,000 scale map. Power and Water Authority, Darwin.

C.8 McArthur Basin

Table C.53 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	Northern Territory, Queensland
Area	~285,000 km2
Maximum basin depth	15,000 m
Maximum sediment thickness (m)	15,000 m
Age range	Paleoproterozoic–Mesoproterozoic
Depositional setting	Mainly shallow marine clastic and carbonate deposits, with some lacustrine and fluvial deposits; minor volcanic and intrusive rocks
Regional structure	Includes the Beetaloo Sub-basin in the SW. Dominant north–south (Batten and Walker fault zones) and east-west to northwest–southeast (Urapunga Fault Zone) fault zones related to strike-slip deformation and eastward-propagating thrust belt.
Overlying basins	Arafura Basin, Georgina Basin, Carpentaria Basin, Dunmarra Basin, Money Shoal Basin
EXPLORATION STATUS	
Seismic lines	8,818 line km, 2D seismic
Number of wells	~35
Exploration status – conventional	Under-explored
Exploration status – shale/ tight gas	Under-explored
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Urapungan Supersystem; McArthur Supersystem)
Prospectivity	High
Conventional discoveries	No commercial discoveries; technical discoveries in the Batten Trough (Glyde gas prospect; Armour Energy, 2017)
Hydrocarbon production – total to date	None to date (AERA, 2018)
2P Reserves	None reported (AERA, 2018)
Remaining resources (reserves + contingent resources)	No conventional resources reported (AERA, 2018); see shale/ tight gas resources 2C resources below
Undiscovered resource estimates	No conventional prospective resources; see prospective shale/ tight gas resources below
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Shale gas, tight gas

Production – shale/ tight gas	None
2P Reserves – shale/ tight gas	None reported
Remaining resources (reserves + contingent resources) – shale/ tight gas	6.6 Tcf shale gas over an area of 1,968 km2 (Table A.3; Origin, 2017)
Undiscovered resource estimates – shale/ tight gas	• 202 Tcf undiscovered shale gas-in-place in the middle Velkerri Formation (Table A.3; Revie, 2017b; Weatherford Labs, 2017) • Best estimate of recoverable shale gas resource of 3 Tcf for the lower Kyalla Formation (prospective area 898 km^2) and 16 Tcf for the middle Velkerri Formation (prospective area 6,092 km^2) (AWT International, 2013) • P50 estimate of potentially recoverable shale gas of 37.29 Tcf for the lower Kyalla Formation and 74.50 Tcf for the middle Velkerri Formation (prospective area unknown; RPS, 2013). • Technically recoverable shale gas of 22 Tcf for the lower Kyalla Formation (prospective area - associated gas 4,100 mi^2, 2,400 mi^2 wet gas, 1,310 mi^2 dry gas) and 22 Tcf for the middle Velkerri Formation (prospective area - associated gas 2,650 mi^2, 2,130 mi^2 wet gas, 2,480 mi^2 dry gas) (EIA, 2013)
Hydrocarbon shows, tests – shale/ tight gas	Amungee (Beetaloo Sub-basin); Glyde (Greater McArthur Basin)

C.8.1 Basin geology

The McArthur Basin is a regionally extensive Paleo- to Mesoproterozoic multiphase intracratonic basin covering an area of approximately 285,000 km^2; it is mainly located in the Northern Territory but extends into northwestern Queensland (Figure C.63; Table C.53; Munson, 2014; Carr et al., 2016). The 28,000 km^2 Beetaloo Sub-basin is located in the southwestern part of the basin. The McArthur Basin is unconformably overlain by the Neoproterozoic to Devonian Georgina Basin and the Mesozoic Carpentaria Basin in the southwest, and Neoproterozoic sediments of the Arafura Basin in the north.

The McArthur Basin contains a thick, mixed carbonate and siliciclastic succession; minor mafic and felsic volcanic rocks are present near the base. Depositional environments range from fluvial and lacustrine to shallow marginal marine (Munson, 2014). The basin succession is subdivided into four major groups—the Tawallah, McArthur, Nathan and Roper groups (Figure C.64; Jackson et al., 1987). The McArthur Basin forms part of a network of similarly aged basins that evolved across the northern Australian craton during the Paleoproterozoic and Mesoproterozoic. It is probably continuous or correlative with the Tomkinson Province succession to the south and the Birrindudu Basin to the west; furthermore parts of the succession can be correlated with the South Nicholson Basin (Roper Group equivalent) and Isa Superbasin to the east (Greater McArthur basin concept; Munson, 2014). The tectonic evolution of the basin is poorly understood, but most models suggest that basin evolution was dominated by extensional tectonics and periods of compressional and strike-slip deformation (Rawlings, 1999).

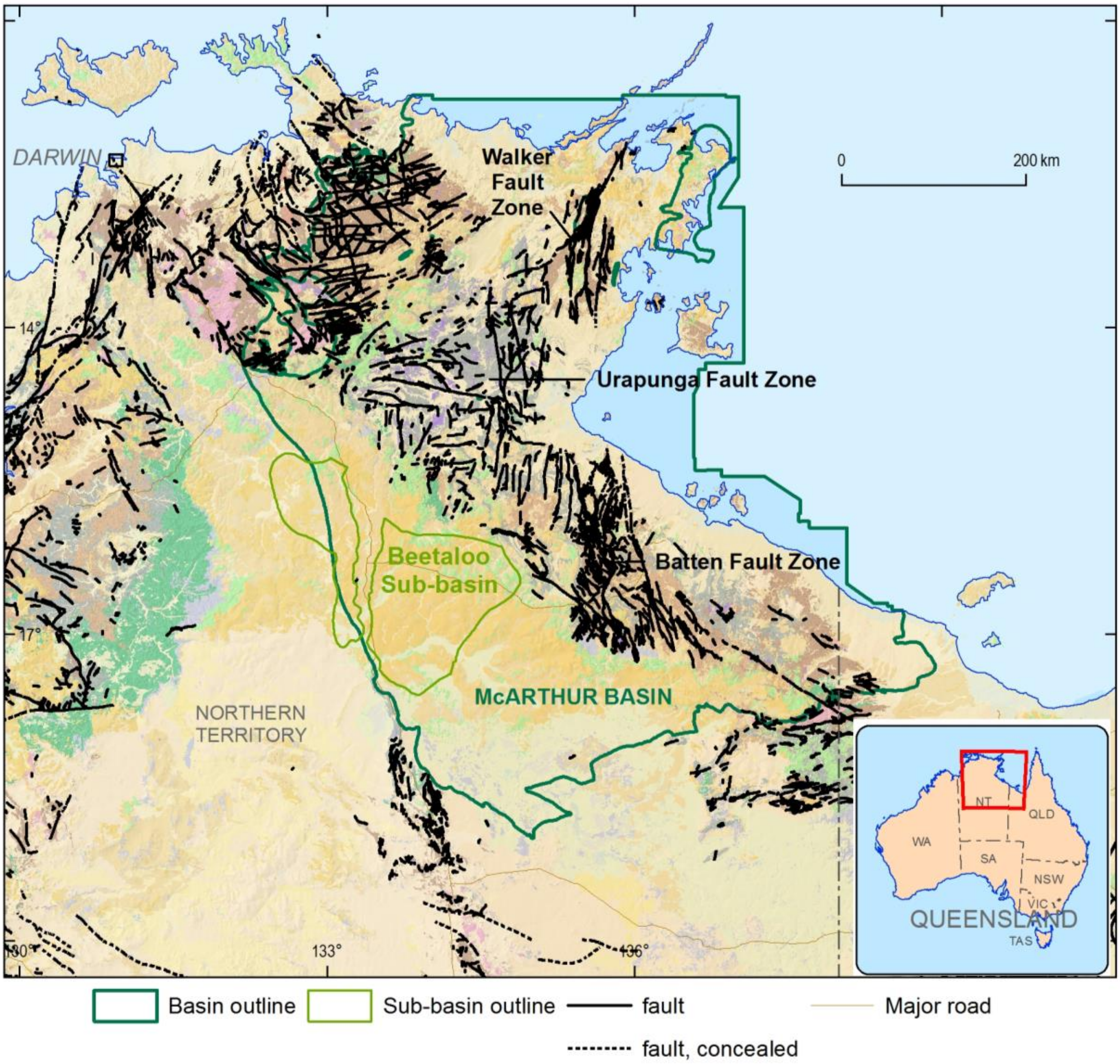

Figure C.63 Location of the McArthur Basin and Beetaloo Sub-basin on a base map of surface geology from Carr et al. (2016). Surface geology is from the 1:1,000,000 scale geology map of Australia (Raymond, 2009); McArthur Basin outline from Stewart et al. (2013) (McArthur) and Beetaloo Sub-basin outline from Williams (in prep).

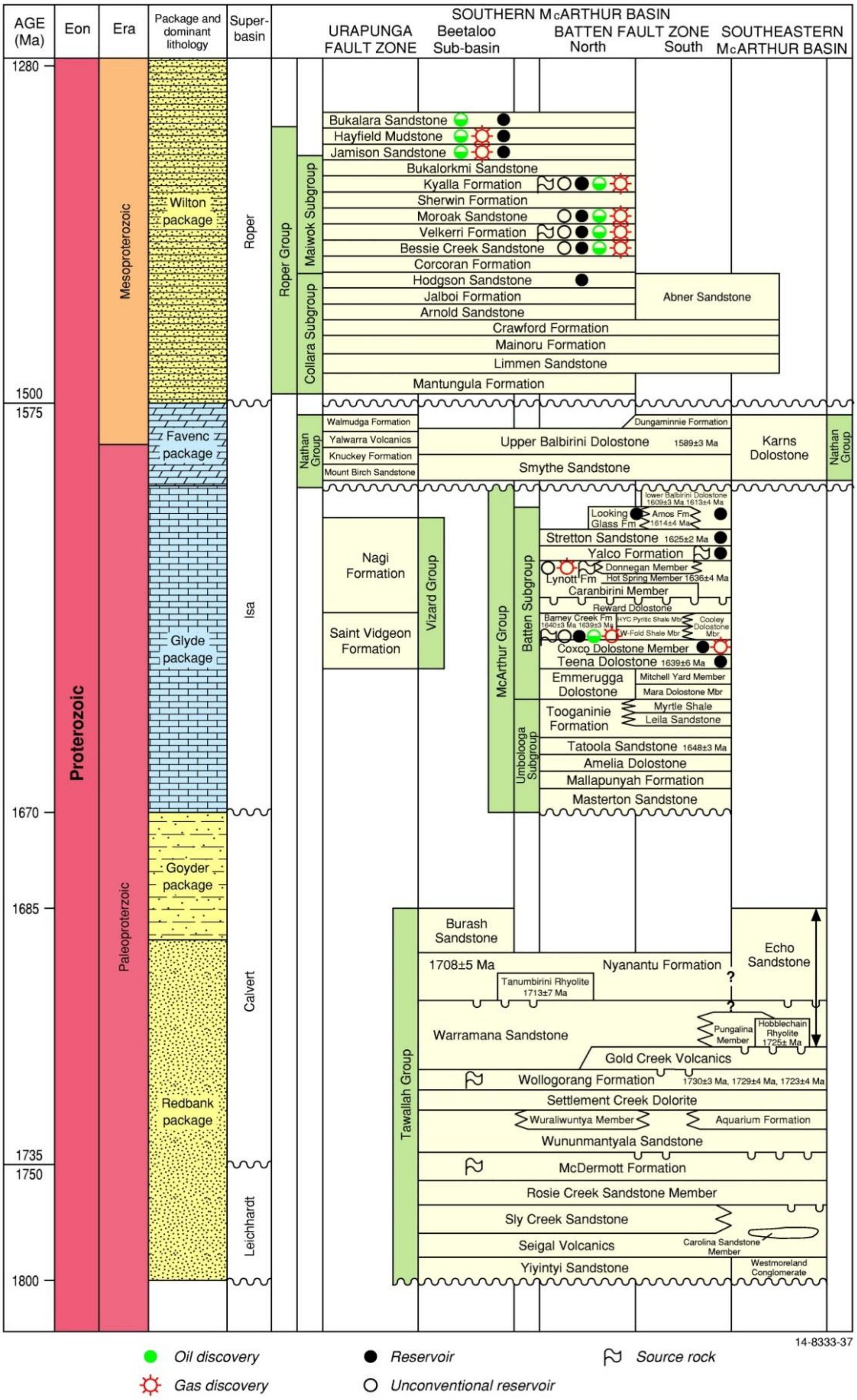

Figure C.64 Stratigraphy of the McArthur Basin from Carr et al. (2016). Correlations of stratigraphic units are based on Rawlings (1999) and Munson. (2014). Also shown is the subdivision of the basin into non-genetic packages (Rawlings, 1999) or superbasins (Jackson et al., 2000), source rock and reservoir units, and petroleum shows (after Munson, 2014).

C.8.2 Petroleum data coverage

Data coverage for the McArthur Basin and Beetaloo Sub-basin is generally sparse with about 8,818 km of open file 2D seismic reflection data, mainly from the Beetaloo Sub-basin (Figure C.65; DNRME, 2017b-d; NTGS, 2017b). No 3D seismic surveys have been acquired. In 2002, Geoscience Australia acquired its Southern McArthur Basin Deep Seismic Survey across the Batten Fault Zone. This consisted of a 110 km long seismic line (02GA-BT1) along the Borroloola–Roper Bar Road and a 20 km long north-south cross line (02GA-BT2; Rawlings et al., 2004).

More than 55 petroleum exploration wells have been drilled in the region (DNRME, 2017a; NTGS, 2017a). Drilling is mostly confined to the Beetaloo Sub-basin, and the Urapunga and Batten fault zones. There are also many mineral drillholes in the region but they tend to be relatively shallow compared to the petroleum exploration wells.

Gravity, aeromagnetic and radiometric datasets are also available across the McArthur Basin and Beetaloo Sub-basin (Carr et al., 2016). These include open file Australian and state/ NT government acquired datasets, as well as those acquired by various mining and petroleum companies. Airborne magnetic and radiometric geophysical data qualities are generally good across the basins, with a line spacing of approximately 400 m or less. Gravity data is fair to poor, as station spacing is sparse (predominantly 11 km), the areas of better quality data have 2–4 km station spacing.

In recent years, the Northern Territory Geological Survey (NTGS) has compiled and reworked existing data as part of their McArthur Basin unconventional hydrocarbon prospectivity project. This has included resampling of 115 wells to characterise the basin’s shale prospectivity and development of a 3D model of the Greater McArthur Basin (Close, 2014; Bruna and Dhu, 2015; Revie, 2017a).

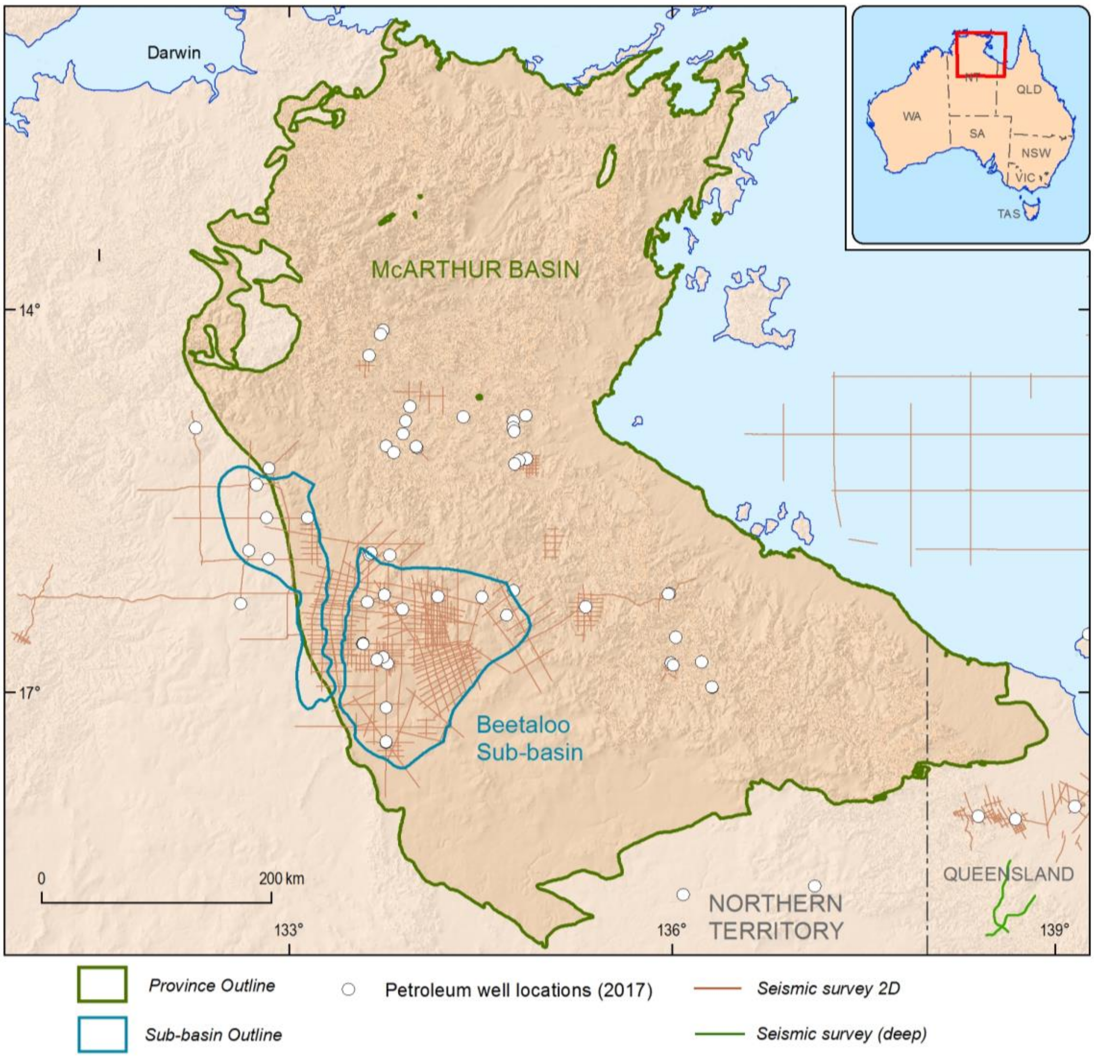

Figure C.65 McArthur Basin petroleum exploration wells and 2D seismic data coverage. McArthur Basin outline from Stewart et al. (2013). Beetaloo Sub-basin outline from Williams (in prep). Petroleum wells from DNRME (2017a) and NTGS (2017a). Seismic data from DNRME (2017b-d) and NTGS (2017b).

C.8.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the McArthur Basin is summarised in Table C.53

Unconventional petroleum resources are key targets in the McArthur Basin (e.g. Silverman and Ahlbrandt, 2010; Close et al., 2014; Connors and Krassay, 2015; Revie and Edgoose, 2015a, 2015b; Revie, 2017a, b). The Barney Creek Formation (McArthur Group) and Velkerri Formation (Roper Group) have been identified as the primary shale gas plays, having the greatest potential for commercial production, and are currently being explored and evaluated (Table C.54; Figure C.66; Armour Energy, 2017; Origin, 2017; Revie, 2017b). Additional units with unconventional potential for shale oil and gas are the Lynott Formation (particularly Caranbirini Member) of the McArthur Group, the Kyalla Formation of the Roper Group, and the Vaughton Siltstone of the Balma Group in the northern McArthur Basin (Table C.54; Munson, 2014). In addition, there is potential for basin-centred/ tight gas plays within the Reward Dolostone of the McArthur Group, and the Bessie Creek and Moroak sandstones of the Roper Group (Table C.54; Munson, 2014; RPS, 2013).

While there is no production from shale or tight gas plays in the McArthur Basin, significant exploration activity is underway (Munson, 2014; Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). More than 30 wells targeting shale gas plays have been drilled within the Beetaloo Sub-basin, and four wells have targeted unconventional plays in the Batten Trough (Figure C.66). Approximately half these wells have been drilled in the last 10 years.

Santos, Origin Energy and Falcon Oil and Gas, and Pangaea Resources are actively investigating shale plays in the Beetaloo Sub-basin. In 2017, following completion of extended production testing at the Amungee NW-1H exploration well (Origin Energy, 2016), Origin booked 2C contingent resources of 6.6 Tcf for the “B shale” member of the Velkerri Formation over an area of 1,968 km^2, across permits EP76, EP98 and EP114 in the Beetaloo Sub-basin (Origin Energy, 2017).

It is important to note these 2C contingent resources have been booked based on the results from one well, however experience in the US highlights that there is commonly a large degree of heterogeneity in production rates from shale gas plays within small areas. In particular, the recovery factor for Amungee NW-1H was reported to be 16% (Falcon, 2017), comparable with well explored shale gas plays in the U.S. Nevertheless, further wells are required to increase confidence in the long-term producibility of the play (Revie, 2017b).

In addition, Armour Energy are actively exploring for unconventional naturally fractured and shale gas accumulations in the Batten Trough. They estimate a mean prospective shale gas resource of 18.6 Tcf within the Barney Creek Formation across permits EP 171 and EP 176 (Armour Energy, 2012, 2017). In addition, another 0.1 Tcf of unconventional gas resource is estimated to be associated with Lynott and Reward formations at the Greater Cow Lagoon Structure (Armour Energy, 2017).

Several regional-scale prospective resource estimates have been published for shale and tight gas plays in the McArthur Basin, as described below:

- RPS reported a P50 estimate of potentially recoverable shale gas resource to be 37.29 Tcf for the lower Kyalla Formation and 74.50 Tcf for the middle Velkerri Formation (prospective area unknown; RPS, 2013). In addition, they reported P50 estimate of potentially recoverable basin-centred gas resources of 5.9 Tcf for the Moroak Sandstone and 44.31 Tcf for the Bessie Creek Sandstone (RPS, 2013).
- The US Energy Information Administration (EIA) reported that that the technically recoverable shale gas in the Beetaloo Sub-basin is 22 Tcf for the lower Kyalla Formation (prospective area - associated gas 4,100 mi^2, 2,400 mi^2 wet gas, 1,310 mi^2 dry gas) and 22 Tcf for the middle Velkerri Formation (prospective area - associated gas 2,650 mi^2, 2,130 mi^2 wet gas, 2,480 mi^2 dry gas) (EIA, 2013).
- AWT International have reported their best estimate of recoverable shale gas resource to be 3 Tcf for the lower Kyalla Formation (prospective area 898 km^2) and 16 Tcf for the middle Velkerri Formation (prospective area 6,092 km^2) (AWT International, 2013).

- Most recently, the Northern Territory Geological Survey published gas-in-place (GIP) estimates for the middle Velkerri Formation of 202 Tcf (Revie, 2017a, b; Weatherford Laboratories, 2017). To enable comparison with the potentially recoverable estimates from the other sources quoted above, applying a generic 10% recovery factor would give a potentially recoverable shale gas resource estimate of 20.2 Tcf.

Although these results highlight the large shale and tight gas resource potential of the McArthur Basin, the full extent of these resources are still poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty. In particular, shale gas recovery factors are very poorly understood and vary significantly between each resource assessment.

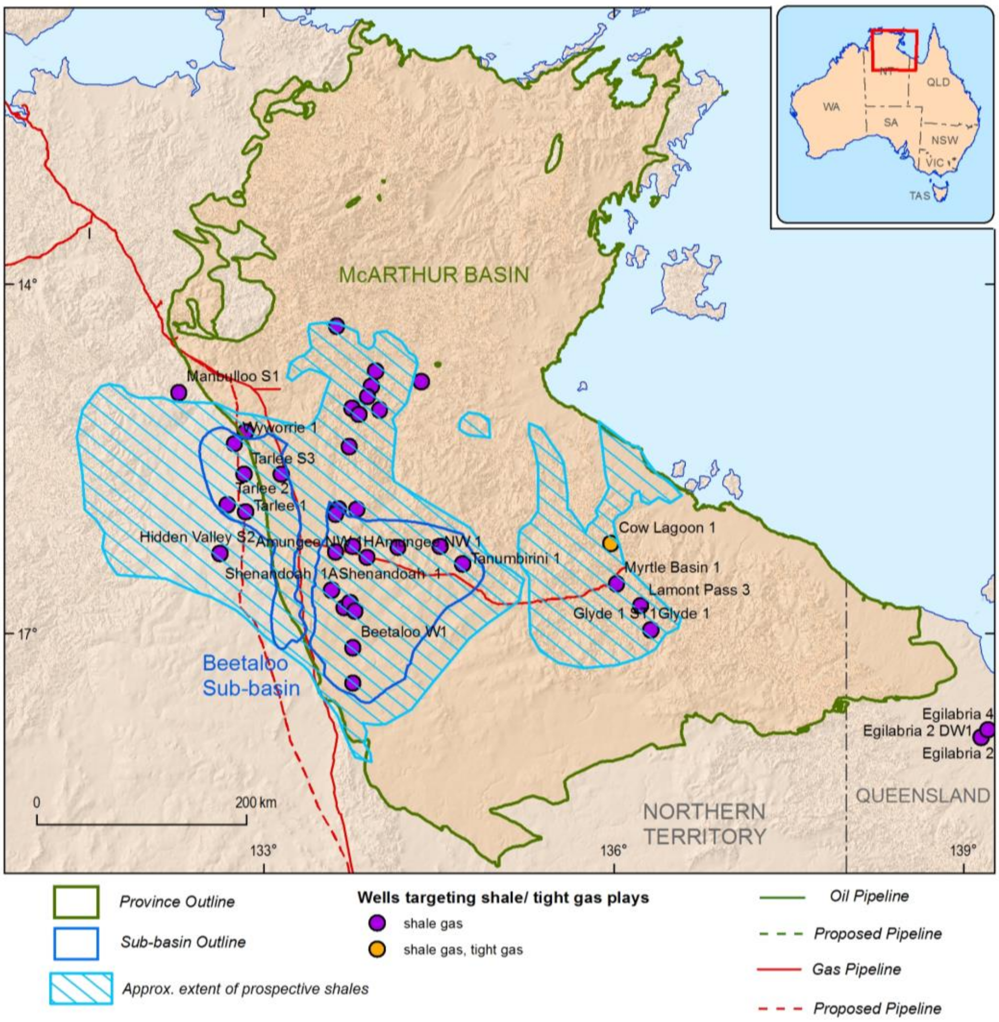

Figure C.66 Wells targeting shale or tight gas plays. McArthur Basin outline from Stewart et al. (2013). Beetaloo Sub-basin outline from Williams (in prep). Approximate areas within which key prospective shales are likely to be present sourced from Bruna and Dhu (2015), Revie (2017a).

Data for the key unconventional hydrocarbon targets are summarised in Table C.54.

Table C.54 Summary of shale and tight gas plays (compiled from Munson et al., 2014; UPR, 2015; Revie, 2017a).

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rock(s)	Source rock TOC (%)	Source rock maturity	Play type	Exploration status
Kyalla Formation (Roper Group)	Mesoproterozoic	shallow to moderately deep marine	550–990	0–800	Type I to II	2–3% Max 4%	Early oil–gas window	shale gas	Active exploration (Origin, 2017)
Moroak Sandstone (Roper Group)	Mesoproterozoic	tide-dominated shoreline	320–1,715	2.5–485	N/A	N/A	N/A	tight gas	Unknown
Velkerri Formation (Roper Group)	Mesoproterozoic	shallow to nearshore marine	230–>2,200	80 to >350	Type I to II	2-6 %. Max 12.5%	Early oil–gas window	shale gas	Under assessment (Origin, 2017)
Bessie Creek Sandstone (Roper Group)	Mesoproterozoic	tide-dominated shoreline	440–1230	20–422	N/A	N/A	N/A	tight gas	Unknown
Vaughton Siltstone (Balma Group)	Paleoproterozoic	deep subtidal	?	600–1000	unknown	unknown		?shale gas	Unknown
Yalco Formation (McArthur Group)	Paleoproterozoic	shallow-marine	?	0–250	Type II	Max. 6%	Marginally mature–over mature	shale gas	Unknown
Lynott Formation (McArthur Group)	Paleoproterozoic	subtidal marine to intertidal	?	50–600	?Type II	0.2–3.4%	Marginally mature–over mature	shale gas	Active exploration (Armour Energy, 2017)
Reward Dolostone (McArthur Group)	Paleoproterozoic	deepwater to shallow marine	260–615	30–350	N/A	N/A	N/A	tight gas, natural fractures	Active exploration (Armour Energy, 2017)
Barney Creek (McArthur Group)	Paleoproterozoic	deeper-water marine	60–650	<200–1,200	Type I to II	0.6–10.4%	Immature–over mature	shale gas	Active exploration (Armour Energy, 2017)

C.8.4 Gas market access and infrastructure

Figure C.67 shows the location of major oil and gas infrastructure in and adjacent to the basin, including oil and gas pipelines, along with the distribution of major road and rail networks. Further details are summarised in Table C.55.

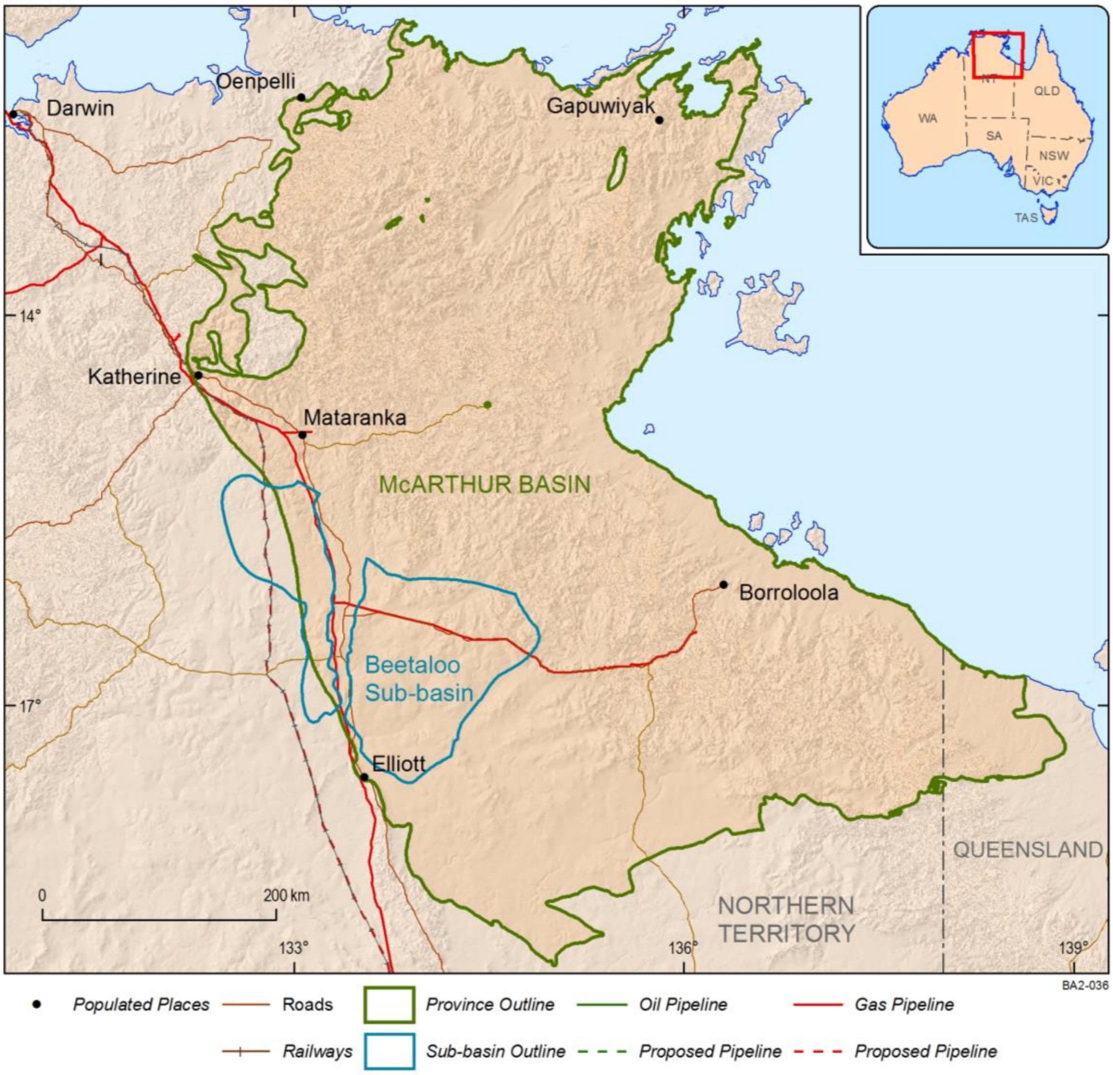

Figure C.67 McArthur Basin infrastructure, pipelines and production facilities. McArthur Basin outline from Stewart et al. (2013). Beetaloo Sub-basin outline from Williams (in prep). Oil and gas infrastructure from GA (2015a).

Table C.55 Summary of market access and infrastructure. Pipeline information from AER (2017) and Jemena (2017). Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	Northern Territory Gas Market
Proximity to gas pipelines	• Daly Waters to McArthur River Pipeline – capacity 16 TJ/day • Amadeus Gas Pipeline – capacity 120 TJ/day
Gas processing facilities	None
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	0–200 km
Road and rail access	Poorly to moderately well serviced
Approximate development timeframe	5–10 years

C.8.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia.

There are no regulatory restrictions affecting the development of shale and or tight gas resources in Queensland. In 2016, the Northern Territory Government implemented a moratorium on unconventional onshore gas activities in the territory, while an inquiry was undertaken and pending the Government's decision on the recommendations of the inquiry; the final report of the inquiry was released in March 2018 (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018). Details of the moratorium and regulatory restrictions are described below.

C.8.5.1 Northern Territory

In April 2018, the Northern Territory Government accepted all 135 recommendations of the inquiry and lifted the moratorium on hydraulic fracturing over 51% of the Territory. An implementation plan to be released in July 2018 will clearly show how the recommendations will be implemented.

C.8.5.2 Queensland

The Queensland Government has no identified constraints to tight and shale gas resource drilling or production stimulation. All planned hydraulic fracture stimulation activities must be reported to the Queensland Department of Natural Resources and Mines (Queensland Government, 2017).

C.8.6 Hydrogeology and groundwater

C.8.6.1 Groundwater systems

The hydrogeology of the McArthur Basin is complex, with many overlying aquifers and aquitards. Groundwater is found within the Paleoproterozoic–Mesoproterozoic McArthur Basin rocks. It is also found within the overlying basins including: the Arafura Basin (Neoproterozoic), Georgina Basin (Neoproterozoic–Devonian), Wiso and Daly basins (Cambrian–Ordovician) and Carpentaria, Dunmarra, and Money Shoal basins (Cretaceous) (Fulton and Knapton, 2015; CSIRO, 2009a; Knapton, 2009a; Bruwer and Tickell, 2015). The groundwater systems sustain flows in regional rivers, springs and support a number of human uses including town water supply, mining and agriculture.

The McArthur Basin succession contains sandstones, shales and carbonates (limestones and dolostones) with interbedded volcanic and intrusive igneous rocks. The Mesoproterozoic dolostones of the Dook Creek Formation (McArthur Basin) are a major aquifer, especially to the north of the Georgina Basin. Apart from the Dook Creek Formation dolostone, most of its aquifer potential is in weathered, fractured zones, especially fractured sandstones, forming localised aquifers (CSIRO, 2009a, 2009b, 2009c; Fulton and Knapton, 2015; Knapton 2009c) (Figure C.68; Table C.56).

Where present, the Cambrian carbonate rocks of the Wiso Basin (Montejinni Limestone), Georgina Basin (Anthony Lagoon and Gum Ridge formations; Thontonia Limestone and Camooweal Dolostone in the east) and Daly Basin (Tindall Limestone) form a single extensive regional aquifer system (the Cambrian Limestone Aquifer) overlying the McArthur Basin and beyond (See Table C.56). The Cambrian Limestone Aquifer is typically fractured and cavernous, allowing bore yields of up to 100 L/s; about 80% of bores screen this limestone, which supplies water for the pastoral industry and local communities. This is the dominant groundwater resource in the region (Knapton, 2009c; Fulton and Knapton, 2015; CSIRO, 2009c, 2009b; Bruwer and Tickell, 2015).

Cretaceous sandstones, such as those in the Carpentaria Basin, are also a major aquifer, particularly to the northeast of the Roper River catchment. Permeable sandstones, which may be over 100m thick, contribute significantly to river baseflow and provide water supply for north east Arnhem Land (CSIRO, 2009b, 2009a).

Fractured rocks of Precambrian and early Cambrian ages, such as those in the Georgina Basin, can also yield groundwater, but these tend to have low yields and are considered only local aquifers. The flow is controlled by the degree of fracturing, especially large-scale jointing and fault zones (CSIRO, 2009b; Fulton and Knapton, 2015; Bruwer and Tickell, 2015). Overlying the northern edge of the McArthur Basin are the Arafura Basin (Neoproterozoic sediments, mostly marine mudstone) and a small part of the Money Shoal Basin (Cretaceous sedimentary clastics including sandstones, coals, shales, marls and claystones). In these basins, Cretaceous sandstones and fractured rocks are generally the only viable aquifers (CSIRO, 2009a).

Alluvial aquifers are located along river valleys and palaeovalleys, and contain localised groundwater resources, typically within the top few metres of sand and gravel (CSIRO, 2009c).

These alluvial aquifers yield much less than the Cambrian Limestone Aquifer, so are generally only suitable for stock watering and used where limestone aquifers are not available (Fulton and Knapton, 2015; Bruwer and Tickell, 2015).

The dolostone/limestone and Cretaceous sandstone formations are considered as 'productive' regional aquifers (CSIRO, 2009b, 2009c). The Hydrogeology of Australia map (Jacobson and Lau, 1987) indicates that outside of these areas, aquifers are typically of low to moderate productivity (Jacobson and Lau, 1987; Zaar, 2003; Zaar et al., 1999).

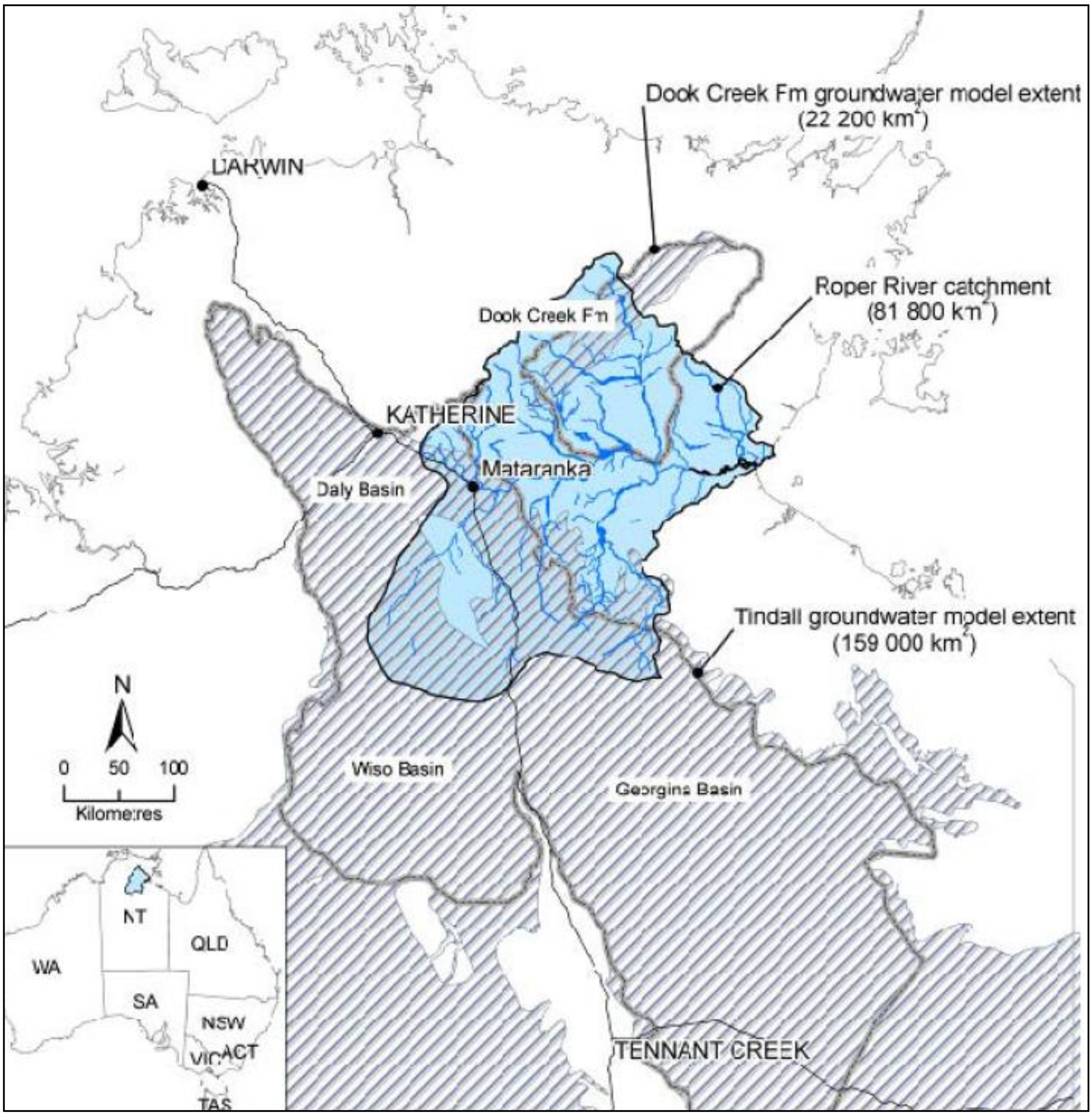

Figure C.68 Location of major aquifers (Cambrian limestones and Mesoproterozoic dolostones) underlying the Roper River catchment and surrounding areas, which overlie a significant area of the McArthur Basin (source: Knapton, 2009a).

Table C.56 Summary of the hydrostratigraphy in and above the Beetaloo Sub-basin (Fulton and Knapton, 2015).

PROVINCE	PERIOD / AGE	FORMATION		AQUIFER STATUS	THICKNESS (m)	YIELD (l/s)	AVE. EC (µs/cm)
CARPENTARIA BASIN	CRETACEOUS 145 – 66 Ma	Undifferentiated		*Local Aquifer*	0 - 130	0.3 - 4	1800
GEORGINA BASIN	CAMBRIAN 497-630 Ma	Cambrian Limestone Aquifer (CLA)	Anthony Lagoon Beds	REGIONAL AQUIFER	0 – 200	1 - 10	1600
			Gum Ridge Formation	REGIONAL AQUIFER	0 – 300	0.3 - >20	1400
		Antrim Plateau Volcanics		REGIONAL AQUITARD *Local Aquifer*	0 – 440	0.3 - 5	900
		Bukalara Sandstone		*Local Aquifer*	0 – 75	0.3 - 5	1000
BEETALOO BASIN (ROPER GROUP)	NOT KNOWN	Hayfield Mudstone		REGIONAL AQUITARD *Local Aquifer*	0 – 450	-	32000
		Jamison Sandstone		*Local Aquifer*	0 – 150	-	138000
	MESO-PROTEROZOIC 1430-1500 Ma	Kyalla Formation		REGIONAL AQUITARD	0 – 800	-	-
		Moroak Sandstone		*Local Aquifer*	0 – 500	0.5 - 5	131000
		Velkerri Formation		REGIONAL AQUITARD	700 – 900	-	-
		Bessie Ck Sandstone		*Local Aquifer*	450	0.5 - 5	-

C.8.6.2 Groundwater quality

Sandstone-dominant formations in the Roper Group (Beetaloo Sub-basin) host highly saline waters, with areas of hypersaline electrical conductivities (EC) of 32,000–159,000 µS/cm (Fulton and Knapton, 2015). In contrast, good quality water is found in the overlying Cambrian and Cretaceous aquifers; mean formation EC values (760–1,780 µS/cm) and is typically acceptable for human consumption (Fulton and Knapton, 2015).

Most limestone aquifer salinities are low to moderate (300–2,000 µS/cm), however highly saline groundwater (EC > 10,000 µS/cm) can be found beneath groundwater discharge areas (CSIRO, 2009b; Fulton and Knapton 2015).

Groundwater from Cretaceous sandstones tend to have very low electrical conductivity (usually EC < 100 µS/cm), however there are patches, such as above the Beetaloo Sub-basin, where EC of up to 4,500 µS/cm have been recorded (Schult, 2014; CSIRO, 2009b, 2009a; Fulton and Knapton, 2015).

Groundwater from fractured rock aquifers is typically low in salinity, but there are some localised exceptions such as beneath the Roper River and Arafura Swamp. These are major discharge points where extensive evapotranspiration occurs and salinity levels increase (CSIRO, 2009b, 2009a; Fulton and Knapton, 2015).

C.8.6.3 Groundwater flow

The Cambrian Limestone Aquifer is the main regional aquifer. Groundwater flows towards and discharges into the Roper and Flora rivers as well as a small number of associated springs such as those found at Mataranka (Figure C.69) (Fulton and Knapton, 2015; Bruwer and Tickell, 2015).

A basement high separates the groundwater flow systems of the Wiso and Georgina basins (Knapton, 2009c). The groundwater flow rates are in the order of metres per year, as the groundwater gradients are very low, at about 0.0001 (Fulton and Knapton, 2015). Regional transmissivity has been estimated at 100–30,000 m^2/day in the Daly Basin; about 5000 m^2/day for limestone and 10,000 m^2/day for Dook Creek dolostone (Bruwer and Tickell, 2015; Knapton, 2009c).

Recharge, at about 5–20 mm/yr, is dominated by macropore and indirect recharge processes such as through sinkholes where Cretaceous cover is limited (Fulton and Knapton, 2015). However, in areas with thick, clayey Cretaceous cover, diffuse recharge is very limited (Bruwer and Tickell, 2015). Recharge to the Cambrian Limestone Aquifer is not well quantified, but estimated to be 7–169 mm/yr (CSIRO, 2009b). Vertical connectivity is not well understood, but it appears that hydraulic gradients lead to upward groundwater flow from the Beetaloo Sub-basin to the Cambrian Limestone and Cretaceous aquifers (Fulton and Knapton, 2015).

Discharge is via evapotranspiration, springs and river baseflow (CSIRO, 2009b). Groundwater from the Cambrian Limestone discharges and supports the Mataranka Thermal Pools, which are listed in the Directory of Important Wetlands in Australia (CSIRO, 2009b). Some small springs in the eastern catchments provide a small flow (less than 10 L/s), and can cease to flow in the dry season (CSIRO, 2009c).

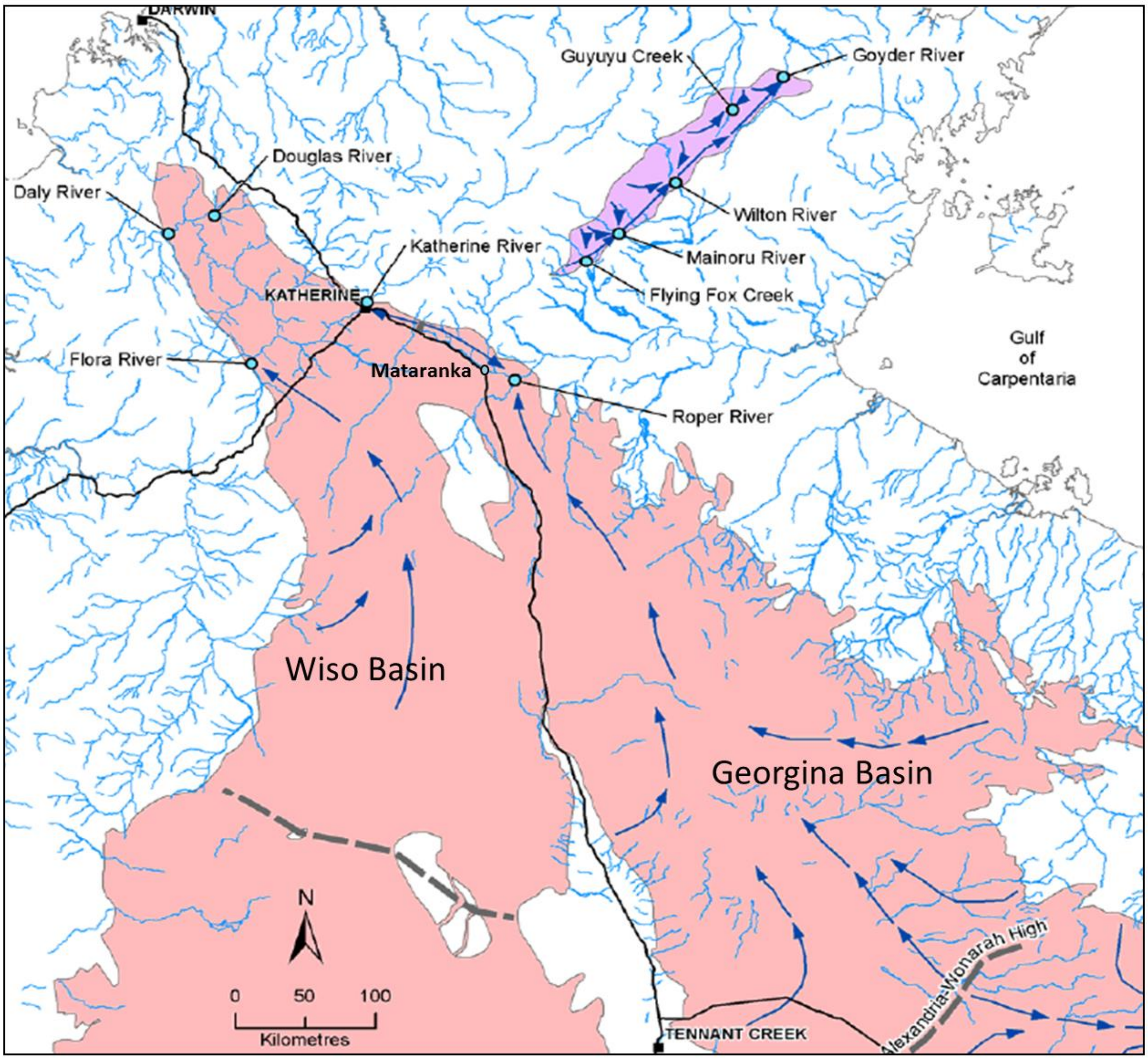

Figure C.69 Regional groundwater flow in the Roper River catchment , showing the Cambrian Limestone (pink) and Dook Creek Formation (purple) aquifers are providing baseflow to the Roper River and tributaries (Knapton, 2009c)

C.8.6.4 Groundwater planning and use

A large portion of the McArthur Basin coincides with the Daly-Roper Water Control District (Fulton and Knapton, 2015; Northern Territory Government, 2016). A Water Allocation Plan limits extraction in the area around Katherine (Fulton and Knapton, 2015; NT DLRM, 2016). Despite water being used for horticulture irrigation and mining, both within and outside the Daly-Roper Water Control District, groundwater use is often not metered, as a result the actual volume of groundwater used is not known (CSIRO, 2009b). Contributing to the demands of the groundwater system, an unknown number of small volume users (less than 5 ML/yr) do not require a license (CSIRO, 2009b).

Licenced groundwater extraction from the Cambrian Limestone Aquifer is used for Mataranka town supply (95 ML/yr) and horticulture (3220 ML/yr) (Knapton, 2009a). Groundwater licences in the Rosie to Koolatong River catchments and the Roper River catchment total 580 ML/yr (CSIRO, 2009b). A fractured Proterozoic sandstone aquifer has been developed for supplying water to Borroloola, with an unknown extraction rate (CSIRO, 2009c). Communities in northeastern Arnhem Land also extract water from Cretaceous sandstones, but do not have licensed limits (CSIRO, 2009a). Arnhem Land extraction is estimated at 500–600 L per person per day, or approximately 6,000 ML/yr (CSIRO, 2009a). At the Century Zinc Mine, there has been an estimated 420 GL of dewatering over 22 years (19 GL/yr) from the Thorntonia Limestone aquifer (CSIRO, 2009c). The Ranger uranium mine extracts a significant but unmetered volume of groundwater, while bauxite mining near Nhulunbuy extracts 10 GL/yr from Cretaceous sandstones (CSIRO, 2009a). The combined take from stock usage and community water supply is estimated at 6000 ML/yr in the Beetaloo Sub-basin (Fulton and Knapton, 2015).

Only 7% of registered bores have sufficient information for identifying the water table, and less than 2% of registered bores are current monitoring bores (CSIRO, 2009b). Bores are not necessarily monitored regularly (CSIRO, 2009a).

Table C.57 presents information from the National Groundwater Information System (BoM, 2016) and shows summary information of registered bores in the basin.

Table C.57 Summary statistics on groundwater bores and water use in and above the McArthur Basin.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	4700 (0.02)	
Purposes of registered bores (Top 5, number)	Stock	4,318
	Monitoring	142
	Irrigated Agriculture	96
	Exploration	42
	Road Supply	30
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile:	14.6
	Median:	50.6
	90th Percentile:	120

C.8.7 Surface water systems and hydrology

C.8.7.1 Surface water systems

The McArthur Basin underlies several catchments draining to the western Carpentaria Coast (Settlement Creek, Robinson River, Calvert River, McArthur River, Rosie Creek, Limmen Bight River, Towns River, Roper River, Walker River, and Koolatong River) and Arafura Sea (Buckingham River, Goyder River, Blyth River, Liverpool River and Goomadeer River), along with the headwaters of other catchments in the Timor-Tanami division (East Alligator River, South Alligator River, Mary River, Daly River and Victoria–Wiso catchments) in the west of the McArthur Basin (BoM, 2014). River catchments are presented in Figure B.17. Poorly resolved catchment boundaries, particularly for sub-catchments, are due to low topographic gradients in the area (Knapton, 2009b).

In the Roper River catchment, the only perennial streams are the lower Waterhouse River, lower Little Roper River, lower Elsey Creek and the Roper River itself (Schult and Novak, 2017). In addition, limestone aquifers support flows in neighbouring Mainoru, Wilton, Koolatong, Walker, Rosie, Flora, Daly, and Goyder rivers and Flying Fox Creek (CSIRO, 2009b). Further north, the Goyder, Blyth and Habgood rivers, including the Arafura Swamp, have perennial reaches supported by the Dook Creek dolostone aquifer; while Cretaceous sandstone aquifers support perennial reaches of the Cato and Latram rivers and Yirrkala and Jungle creeks (CSIRO, 2009a). To the east, the Gregory, Calvert and Robinson rivers and Lawn Hill Creek are also perennial, with karstic carbonate aquifers providing small but significant baseflow via small springs, while Cretaceous sediments support additional baseflow to the lower Calvert River (CSIRO, 2009c). These few perennial reaches are of high ecological importance (Knapton, 2009a). The Durabudboi River and Wonga Creek receive baseflow from Cretaceous sediments, with recharge closer to the Arafura Sea (CSIRO, 2009b). Flooding and bank-full discharge is an important factor in sustaining environmental assets; however knowledge of these factors in the region is poor due to the lack of stream gauging on ephemeral and intermittent rivers (CSIRO, 2009a, 2009b).

C.8.7.2 Surface water quality

Surface water quality is influenced by a number of factors, including inflowing groundwater quality, rainfall runoff and evaporation. The Roper River, for example, typically has high salinity (typically 1000–1500 µS/cm EC) with occasional areas exceeding 2000 µS/cm, indicative of poorer quality groundwater baseflow. In contrast, the Katherine and Daly rivers have lower salinities (EC < 700 µS/cm), possibly due to discharge of low salinity groundwater from the Cretaceous sandstone aquifer.

In the Roper River, salinity levels generally increase towards the coast, due to evapotranspiration. Wet season storm events increase the flow in the Roper River, reducing salinity and increasing turbidity (Schult and Novak, 2017; Schult, 2014).

C.8.7.3 Surface water flow

A series of 42 surface water gauging stations are located across the region to monitor the annual monsoonal inputs to the river flows. There are 17 gauges in the Arafura region, 22 in the Roper region, and three in the McArthur-Calvert-Robinson region. Most stream gauges are located in the upper reaches, and almost none are currently operating (CSIRO, 2009c, 2009b, 2009a).

Average dry season streamflows at gauging sites are generally 0.5–3.5 m^3/s (Table C.58, Knapton, 2009b, 2009c). Monthly discharges on the Roper River at 'Red Rock' vary from a maximum in March (83 m^3/s) to a minimum in September–October (3.5 m^3/s), which shows the effect of the wet season (Knapton, 2009b). Baseflow to the Roper River is estimated at 3–4 m^3/s (Knapton, 2009b).

Several rivers are also groundwater fed. For example the Cambrian Limestone Aquifer provides baseflow to the Roper, Katherine and Daly rivers; the Dook Creek Formation provides baseflow to some tributaries of the Roper River, as well as the Goyder and Blyth rivers (Knapton, 2009a; CSIRO, 2009a; Schult and Novak, 2017).

Downstream of Mataranka Springs, dry season flows are reduced, due to groundwater seepage out of the river channel and evapotranspiration (Schult and Novak, 2017). When flows at Mataranka Springs drop below 2.5 m^3/s, no streamflow will reach the Roper River estuary (CSIRO, 2009b). In other locations, the ephemeral streams flow after the wet season rainfall events are otherwise observed as a chain of isolated pools, and tend to run dry in August/September (Faulks, 2001). These series of disconnected pools tend to overlie fractured rock aquifers (CSIRO, 2009a).

Table C.58 Average discharge measurements from gauging stations (Knapton 2009c).

Catchment	Gauge Site	River	Average Dry Season discharge [m3/s]
Roper River	G9030176	Roper	1.5
	G9030013	Roper	3.1
	G9030108	Flying Fox	0.8
	G9030074	Mainoru	1.0
	G9030003	Wilton	1.0
Daly River	G8140301	Katherine	1.6
	G8140044	Flora	2.3
	G8145107	Douglas	1.0
	G8140040	Daly	1.0
Goyder River	G9250001	Annie Creek	0.5
	G8250002	Goyder River	2.5
Blyth River	G8250002	Blyth	1.0

C.8.7.4 Surface water dams, planning and use

There are no large surface water storages in the region (CSIRO, 2009b, 2009a, 2009c). The only substantive surface-water entitlement is 340 ML/yr for the community of Ngukurr, which relies on freshwater stored in a large pool on the Roper River (Knapton, 2009a; CSIRO, 2009b). Some extraction of water from rivers and creeks occurs for stock and domestic purposes. A 'Water Extraction License' is required for larger extractions for irrigation, domestic and mining purposes. There are four licenses for community supply purposes and two for gardens at Roper Bar; these six licenses total 403 ML/yr (Faulks, 2001). The Elsey National Park holds another 72 ML/yr entitlement for extraction from the Roper River (Knapton, 2009a).

C.8.8 Groundwater–surface water interactions

Perennial streams are generally located on top of relatively productive aquifers such as the Cambrian limestones and Cretaceous sandstones (Schult and Novak, 2017; Knapton, 2009c; Fulton and Knapton, 2015; CSIRO, 2009a, b & c). Regional groundwater flow is typically towards discharge features such as springs and perennial rivers, thus linking the entire groundwater system with surface water features (Figure C.69). The surface water chemistry is strongly associated with the input aquifer types, especially during periods of low flow where baseflow dominates streamflow (Schult and Novak, 2017; Schult, 2014). In locations where aquifers are unable to provide baseflow, reaches tend to be ephemeral and reliant on wet-season storm events. In some locations, streamflow is derived from an upstream baseflow fed section, but evapotranspiration and losing stream hydraulic gradients lead to diminishing streamflows (Schult and Novak, 2017; CSIRO, 2009b; Knapton, 2009b).

C.8.9 Environmental assets

Within the McArthur Basin there are 5,352 km^2 of Listed Nationally Important Wetlands, 8,990 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential) and part of the Ramsar-listed Kakadu National Park wetland; Kakadu is also a World Heritage Area and a National Park managed at a Commonwealth level (DSEWPC, 2012). A total of 19,620 km^2 of protected areas (such as national parks) are listed. Table C.59 provides details of these assets.

Table C.59 Summary of environmental assets

Environmental Assets		
Ramsar Wetlands	Kakadu National Park	
Nationally Important Wetlands Top 5 by area (area km^2)	Limmen Bight (Port Roper) Tidal Wetlands System	2,059
	Arafura Swamp	1,004
	Wentworth Aggregation	828
	Port McArthur Tidal Wetlands System	533
	Tarrabool Lake	469
	TOTAL WETLAND AREA	5,352
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	National Park	11,535
	National Park (Commonwealth)	4,005
	NRS Addition - Gazettal in Progress	1,974
	Biodiversity Hotspot	1,964
	Conservation Reserve	128
	TOTAL PROTECTED AREA	19,620
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	8990	

C.8.10 Social considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in the Table C.60.

Table C.60 Summary of population, land use and aboriginal protected area

GENERAL CHARACTERISTICS		
Population	29,784	
Major population centres (two)	Katherine, Maningrida	
Land use types Top 5 by area (area km^2)	Grazing native vegetation	139,841
	Other Protected areas	117,932
	Nature Conservation	20,578
	Minimal use	5,608
	Urban intensive uses	640
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	135,812	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

AERA (Australian Energy Resources Assessment) (2018) Australian Energy Resources Assessment interim report, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.ga.gov.au/aera>.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

Armour Energy (2012) Replacement prospectus 2012. Viewed 08/07/2017, <http://www.armourenergy.com.au/assets/downloads/prospectus/armour-energy-limited-prospectus_with-apps_20120320.pdf>.

Armour Energy (2017) Northern Territory. Viewed 22/01/2018, <https://www.armourenergy.com.au/northern-territory/>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016). National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

Bruna PO and Dhu T (2015) 3D model of the greater McArthur Basin, Version 2015.1. Northern Territory Geological Survey, Digital Information Package DIP 012.

Bruwer Q and Tickell SJ (2015) Daly Basin Groundwater Resource Assessment - North Mataranka to Daly Waters, Department of Land Resource Management, Water Resources Report Number 20/2015D

CAPAD (2016) Collaborative Australian Protected Area Database, 2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Carr LK, Korsch RJ, Palu TJ and Reese B (2016) Onshore Basin Inventory: the McArthur, South Nicholson, Georgina, Wiso, Amadeus, Warburton, Cooper and Galilee basins, central Australia. Record 2016/04. Geoscience Australia, Canberra. Viewed 22/01/2018, <http://dx.doi.org/10.11636/Record.2016.004>.

CSIRO (2009a) Water in the Arafura region. In: CSIRO (2009) Water in the Timor Sea Drainage Division. A report to the Australian Government from the CSIRO Northern Australia Sustainable Yields Project. CSIRO Water for a Healthy Country Flagship, Australia, 453-507

CSIRO (2009b) Water in the Roper region. In: CSIRO (2009) Water in the Gulf of Carpentaria Drainage Division. A report to the Australian Government from the CSIRO Northern Australia Sustainable Yields Project. CSIRO Water for a Healthy Country Flagship, Australia. 59-120

CSIRO (2009c) Water in the South-West Gulf region. In: CSIRO (2009) Water in the Gulf of Carpentaria Drainage Division. A report to the Australian Government from the CSIRO Northern Australia Sustainable Yields Project. CSIRO Water for a Healthy Country Flagship, Australia, 121-185

Close DF (2014) The McArthur Basin: NTGS' approach to a frontier petroleum basin with known base metal prospectivity. In: Annual Geoscience Exploration Seminar (AGES) 2014. Record of abstracts. Northern Territory Geological Survey, Record, 2014-001, 85–89.

Close D, Côté A, Baruch E, Altmann C, Mohinudeen F, Richards B, Ilett R, Evans R and Stonier S (2017) Exploring the Beetaloo: will Australia's first viable shale play be sourced by billion year old gas? The APPEA Journal 57(2).

Connors K and Krassay A (2015) Understanding unconventional petroleum resources of the greater McArthur Basin from potential field, well and seismic data. In: Annual Geoscience Exploration Seminar (AGES) 2015. Record of abstracts. Northern Territory Geological Survey, Record, 2015-002, 31–33.

DNRM (Department of Natural Resources and Mines) (2017) Queensland's unconventional petroleum potential – shale oil and gas, tight gas and coal seam gas. Department of Natural Resources and Mines, Queensland. Viewed 16/01/2018, <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>.

DNRME (Department of Natural Resources, Mines and Energy) (2017a) Petroleum well locations – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d>.

DNRME (Department of Natural Resources, Mines and Energy) (2017b) Seismic survey 2D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017c) Seismic survey 3D – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DNRME (Department of Natural Resources, Mines and Energy) (2017d) Seismic survey deep – Queensland. Viewed 23/07/2017, <http://qldspatial.information.qld.gov.au/catalogue/custom/index.page>.

DSEWPC (Department of Sustainability, Environment, Water, Population and Communities) (2012) Kakadu National Park – a distinctive natural and cultural experience. In: Wetlands Australia National Wetlands Update 2012, Issue No. 20, February 2012. Hosted on the website of the Department of the Environment and Energy. Viewed 09/08/2017, <http://www.environment.gov.au/water/wetlands/publications/wetlands-australia/national-wetlands-update-february-2012-8>.

EIA (Energy Information Administration) (2013) Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. United States Energy Information Administration, 730 p. Viewed 16/01/2018, <https://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf>.

Falcon (2017) Beetaloo Basin drilling results indicate material gas resource. Viewed 22/01/2018, <www.falconoilandgas.com/uploads/pdf/Beetaloo_material_gas_resource.pdf>.

Faulks JJ (2001) An Assessment of the Physical and Ecological Condition of the Roper River and its Major Tributaries. Northern Territory Government Department of Lands, Planning and Environment, Technical Report No. 36/2001, January 2001, Katherine.

Fulton S and Knapton A (2015) Beetaloo Basin Hydrogeological Assessment. CloudGMS report to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory. Viewed 05/07/2017, <https://frackinginquiry.nt.gov.au/?a=410609>.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

Jackson MJ, Muir MD and Plumb KA (1987) Geology of the southern McArthur Basin, Northern Territory. Bureau of Mineral Resources, Bulletin, 220, 173 pp.

Jackson MJ, Scott DL and Rawlings DJ (2000) Stratigraphic framework for the Leichhardt and Calvert superbasins: review and correlation of the pre-1700 ma successions between Mt Isa and McArthur River. Australian Journal of Earth Sciences, 47, 381–403.

Jacobson G and Lau JE (1987) Hydrogeology of Australia, Geoscience Australia. Viewed 10/07/2017, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7892-72bf-7506-e044-00144fdd4fa6>.

Jemena (2017) Northern gas pipeline. Viewed 16/01/2018, <http://jemena.com.au/industry/pipelines/northern-gas-pipeline>.

Knapton A (2009a) An integrated surface – groundwater model of the Roper River Catchment, Northern Territory: Part A - Coupled Surface – Groundwater model. Gulf Water Study, Northern Territory Government Department of Natural Resources, Environment, the Arts and Sport, Technical Report No. 15/2009D

Knapton A (2009b) Integrated Surface - Groundwater Model of the Roper River Catchment: Part B: MIKE11 Surface Water Model. Gulf Water Study, Northern Territory Government Department of Natural Resources, Environment, The Arts and Sport, Technical Report No. 31/2009D

Knapton A (2009c) Integrated Surface - Groundwater Model of the Roper River Catchment: Part C: FEFLOW Groundwater Model. Gulf Water Study, Northern Territory Government Department of Natural Resources, Environment, the Arts and Sport, Technical Report No. 32/2009D

Munson TJ (2014) Petroleum geology and potential of the onshore Northern Territory, 2014. Northern Territory Geological Survey, Report 22, 242 pp.

Northern Territory Government (2016) "NT Declared Water Control Districts", Map of Water Control Districts in the Northern Territory of Australia. Drawing Ref DENR2016025, November 2016. Viewed 29/09/2017, <http://www.ntlis.nt.gov.au/mpds/get_file?file_id=4072>.

NT DLRM (2016) "Water Allocation Plan: Tindall Limestone Aquifer, Katherine, 2016-2019". Document No: 08/2016/D. Department of Land Resource Management, Northern Territory Government. Water allocation plan made under the Water Act 1992 (NT). Viewed 29/09/2017, <https://denr.nt.gov.au/__data/assets/pdf_file/0020/254612/water-allocation-plan-tindall-2016-2019.pdf>.

NTGS (Northern Territory Geological Survey) (2017a) Geoscience exploration and mining information system (GEMIS) – Petroleum wells. Viewed 11/08/2017, <http://www.geoscience.nt.gov.au/gemis/ntgsjspui/handle/1/79187>.

NTGS (Northern Territory Geological Survey) (2017b) Northern Territory Statewide Geophysics – Seismic Lines. Viewed 11/08/2017, <http://www.ntlis.nt.gov.au/metadata/export_data?type=html&metadata_id=FB25348A02CB16B2E040CD9B2144584B>.

Origin Energy (2016) Beetaloo extended production test successfully completed. Viewed 16/01/2018, <https://www.originenergy.com.au/content/origin-ui/en/about/investors-media/media-centre/beetaloo-extended-production-test-successfully-completed.html>.

Origin Energy (2017) Beetaloo Basin drilling results indicate material gas resources. Viewed 16/01/2018, <https://www.originenergy.com.au/about/investors-media/media-centre/beetaloo-basin-drilling-results-indicate-material-gas-resource.html>.

Queensland Government (2017) Drilling, completion and abandonment of petroleum wells. Viewed 22/01/2018, <https://www.business.qld.gov.au/industries/mining-energy-water/resources/applications-compliance/lodging-statutory-reports/petroleum-gas-reporting/petroleum-wells>.

Raymond OL (Coordinator) (2009) Surface geology of Australia 1:1 million scale digital geology data: Geoscience Australia, Digital Geology Map. Viewed 16/01/2018, <https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=69455>.

Rawlings DJ (1999) Stratigraphic resolution of a multiphase intracratonic basin system: the McArthur Basin, northern Australia. Australian Journal of Earth Sciences, 46, 703–723.

Rawlings DJ, Korsch RJ, Goleby BR, Gibson GM, Johnstone DW and Barlow M (2004) The 2002 southern McArthur Basin seismic reflection survey. Geoscience Australia, Record, 2004/17, 78 pp.

Revie D (2017a) Unconventional petroleum resources of the Roper Group, McArthur Basin. Northern Territory Geological Survey, Record 2017-002.

Revie D (2017b) Volumetric resource assessment of the lower Kyalla and middle Velkerri formations of the McArthur Basin. AGES conference, Alice Springs, March 2017.

Revie D and Edgoose C (2015a) Unlocking potential for unconventional petroleum resources in the frontier McArthur Basin, Northern Territory: Annual Geoscience Exploration Seminar (AGES) 2015. Record of abstracts. Northern Territory Geological Survey, Record, 2015-002, 48–50.

Revie D and Edgoose C (2015b) Unlocking potential for unconventional petroleum resources in the frontier McArthur Basin, Northern Territory, Australia. AAPG/SEG International Conference and Exhibition 2015, 13–16 September, Melbourne, Australia.

RPS (2013) Evaluation of the hydrocarbon resource potential pertaining to certain acreage interest in the Beetaloo Sub-basin, onshore Australia and Mako Trough, onshore Hungary. Report prepared for Falcon oil and gas. Viewed 22/01/2018, <http://www.falconoilandgas.com/uploads/pdf/UCV02226_Falcon_Combined_CPR_release_Main_Body.pdf>.

Schult J and Novak P (2017) Water Quality of the Roper River 2012-2016. Northern Territory Department of Environment and Natural Resources, Report No. 2/2017D. Palmerston.

Schult J (2014) End of dry season water quality in the Daly and Roper River catchments 2012-2013. Northern Territory Government Department of Land Resource Management, Report No. 03/2014D. Palmerston.

Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018) Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Final Report, March 2018. Viewed 23/04/2018, <https://frackinginquiry.nt.gov.au/inquiry-reports?a=494286>.

Silverman MR, Landon SM, Leaver JS, Maher TJ and Berg E (2007) No fuel like an old fuel: Proterozoic oil and gas potential in the Beetaloo Basin, Northern Territory, Australia. In: Munson TJ and Ambrose GJ (eds), Proceedings of the Central Australian Basins Symposium (CABS), Alice Springs, Northern Territory, 16–18 August 2007. Northern Territory Geological Survey Publication, 2, 205–215.

Silverman MR and Ahlbrandt T (2010) Mesoproterozoic unconventional plays in the Beetaloo Basin, Australia: the world's oldest petroleum systems. In: AAPG International Conference and Exhibition, Calgary, Alberta, 12–15 September 2010. Search and Discovery Article #10295, web posted 21 January 2011), Viewed 20/01/2015, <http://www.searchanddiscovery.com/documents/2011/10295silverman/ndx_silverman.pdf>.

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

UPR (Upstream Petroleum Resources Working Group) (2015) Coal seam, shale and tight gas in Australia: resources assessment and operation overview 2015, Geoscience Australia, Canberra. Viewed 16/01/2018, <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/UPR%20Unconventional%20Resources%20Report%202015%20-%20Final_0.pdf>.

Weatherford Laboratories (2017) Kyalla and middle Velkerri Resource Assessment: Gorrie, Beetaloo, OT Downs, and Broadmere Sub-basins. Study Project No. AB.74329. Northern Territory Geological Survey, Record 2017.003.

Williams B (in prep) Interpretation and definition of the Beetaloo Sub-basin. Northern Territory Geological Survey, Record.

Zaar U (2003) Water Resources of West Arnhem Land. Northern Territory Department of Infrastructure, Planning and Environment, Report No. 34/2003D. Darwin.

Zaar U, Prowse G and Matthews I (1999) Water Resources of East Arnhem Land. Northern Territory Department of Lands, Planning and Environment, Report No. 02/1999D. Darwin.

C.9 Otway Basin (Onshore)

Table C.61 Geology and petroleum prospectivity summary.

GENERAL	
Jurisdiction	South Australia, Victoria
Area	26,460 km2
Max. basin thickness/ sediment thickness	> 4,000 m
Age range	Jurassic–Cenozoic
Depositional setting	Fluvial-lacustrine overlain by deltaic and marine clastic and carbonate environments; overlying Plio-Pleistocene volcanics
Regional structure	West–east-trending extensional basin with three major compressive phases
EXPLORATION STATUS	
Seismic lines	30,000 km 2D seismic; 10 3D surveys
Number of wells	~270 (157 in Vic; 113 in SA)
Exploration status - conventional	Mature
Exploration status – shale/ tight gas	Preliminary exploration
PETROLEUM PROSPECTIVITY - GENERAL	
Petroleum systems	Proven (Austral 1 and 2)
Prospectivity	Moderate–high
Conventional discoveries	Ladbroke Grove, Katnook, Haselgrove and Redman gas fields ceased production in 2011; Port Campbell gas – e.g. Wallaby Creek, North Paarate, Iona; Caroline and Boggy Creek CO_2 fields
Hydrocarbon production – total to date	SA ~67 Bcf gas, ~65,800 kL condensate; Vic ~86 Bcf gas (Goldie Divko, 2015); 1.15 Tcf cumulative conventional gas production (includes offshore Otway Basin and Bass Basin; current to 2014; AERA, 2018)
2P Reserves	0.69 Tcf conventional gas (includes offshore Otway Basin and Bass Basin; current to 2014; AERA, 2018)
Remaining resources (reserves + contingent resources)	1.5 Tcf conventional gas (includes offshore Otway Basin and Bass Basin; current to 2014; AERA, 2018)
Undiscovered resource estimates	900 Bcf in South Australia (DPCSA, 2017e); see below for shale and tight gas
PETROLEUM PROSPECTIVITY – SHALE/ TIGHT GAS	
Unconventional play types	Tight gas; shale gas
Production – shale/ tight gas	None

2P Reserves – shale/ tight gas	No reserves booked
Remaining resources (reserves + contingent resources) – shale/ tight gas	None reported (AERA, 2018)
Undiscovered resource estimates – shale/ tight gas	• Potentially recoverable gas-in-place resources of 5.8 Tcf of tight gas (prospective area 17,233 km^2) and 1.6 Tcf of shale gas (prospective area wet gas 628 km^2; dry gas 369 km^2) (assuming a 5% recovery factor at P50) (Table A.3; GA, 2017; AERA, 2018) • Best estimate recoverable tight gas resource of 9 Tcf of dry gas in the Eumeralla Formation over a prospective area of 4,109 km^2 (AWT International, 2013) • 27 Tcf shale gas in the Casterton Formation for Victorian permit PEP 171 Vic (Goldstein et al., 2012)
Hydrocarbon shows, tests – shale/ tight gas	Moreys 1 DST flowed gas and condensate from Eumeralla Fm

C.9.1 Basin Geology

The Late Jurassic–Cenozoic Otway Basin is a large, northwest trending basin that covers an area of 150,000 km^2, 80% of which lies offshore on the southern–southeastern Australian margin (Figure C.70). Exploration is mature onshore and immature offshore, with ~270 onshore wells and more than 335 offshore wells. Commercial gas discoveries include industrial grade CO_2. No commercial oil discoveries have been identified.

The basin is structurally complex and formed by multi-stage rift-sag and inversion phases. Late Jurassic to Early Cretaceous rifting resulted in the roughly east–west-trending inner Otway Basin. Late Cretaceous rifting, culminating in continental breakup in the Maastrichtian, produced northwest–southeast-trending depocentres beneath the outer shelf and slope. Multiple phases of compression during the Cretaceous–Quaternary resulted in inversion and wrenching of pre-existing structures (Krassay et al., 2004).

The latest Jurassic–Lower Cretaceous Otway Supergroup comprises up to 8 km of continental and fluvio-lacustrine sediments that accumulated in graben and half-graben of the initial rifting event (Figure C.71; Boult and Hibburt, 2002). A thick, post-rift, mudstone-dominated, volcaniclastic succession (Eumeralla Formation) was deposited during a relatively quiescent basin phase in the Aptian and Albian (Krassay et al., 2004). The overlying coastal plain, deltaic and marine sediments of the Upper Cretaceous Sherbrook Group are up to 5 km thick in the offshore basin and less than 200 m thick onshore. The Paleocene–middle Eocene Wangerrip Group sediments were deposited in coastal plain, deltaic and inner shelf settings and are separated from the open-marine, mixed carbonates/siliciclastics of the Eocene–Miocene age by a major unconformity. Onshore, Pliocene and Pleistocene volcanics intrude and overlie Plio-Pleistocene siliciclastic and carbonate sequence and record a recent period of igneous activity in the Otway Basin (Boult and Hibburt, 2002).

The main conventional exploration targets in the Otway Basin are the Upper Cretaceous Waarre Sandstone at the base of the Sherbrook Group, and sandstones of the Pretty Hill Formation and Katnook Sandstone/Windermere Sandstone Member in the Lower Cretaceous Crayfish Subgroup.

The main source rocks of mixed lithofacies occur in the Lower Cretaceous succession. Multiple charge histories are evident in the widespread influx of overmature, dry gas (most prominent in the western Otway Basin) and a more recent influx of magmatic CO_2.

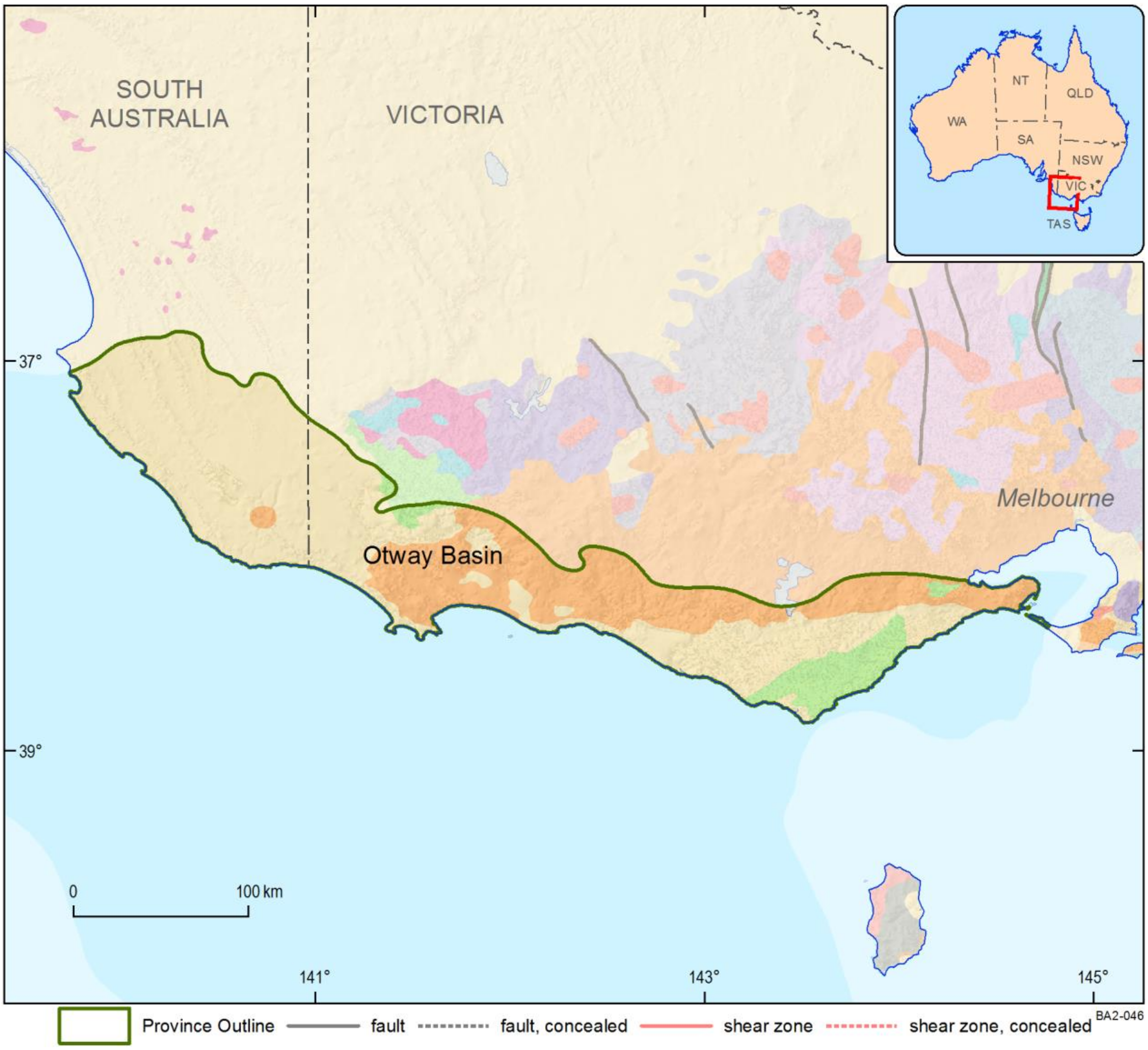

Figure C.70 Location of the onshore Otway Basin on a base map of 1:2,500,000 scale surface geology (Raymond et al., 2012). Onshore basin outline from Stewart et al. (2013).

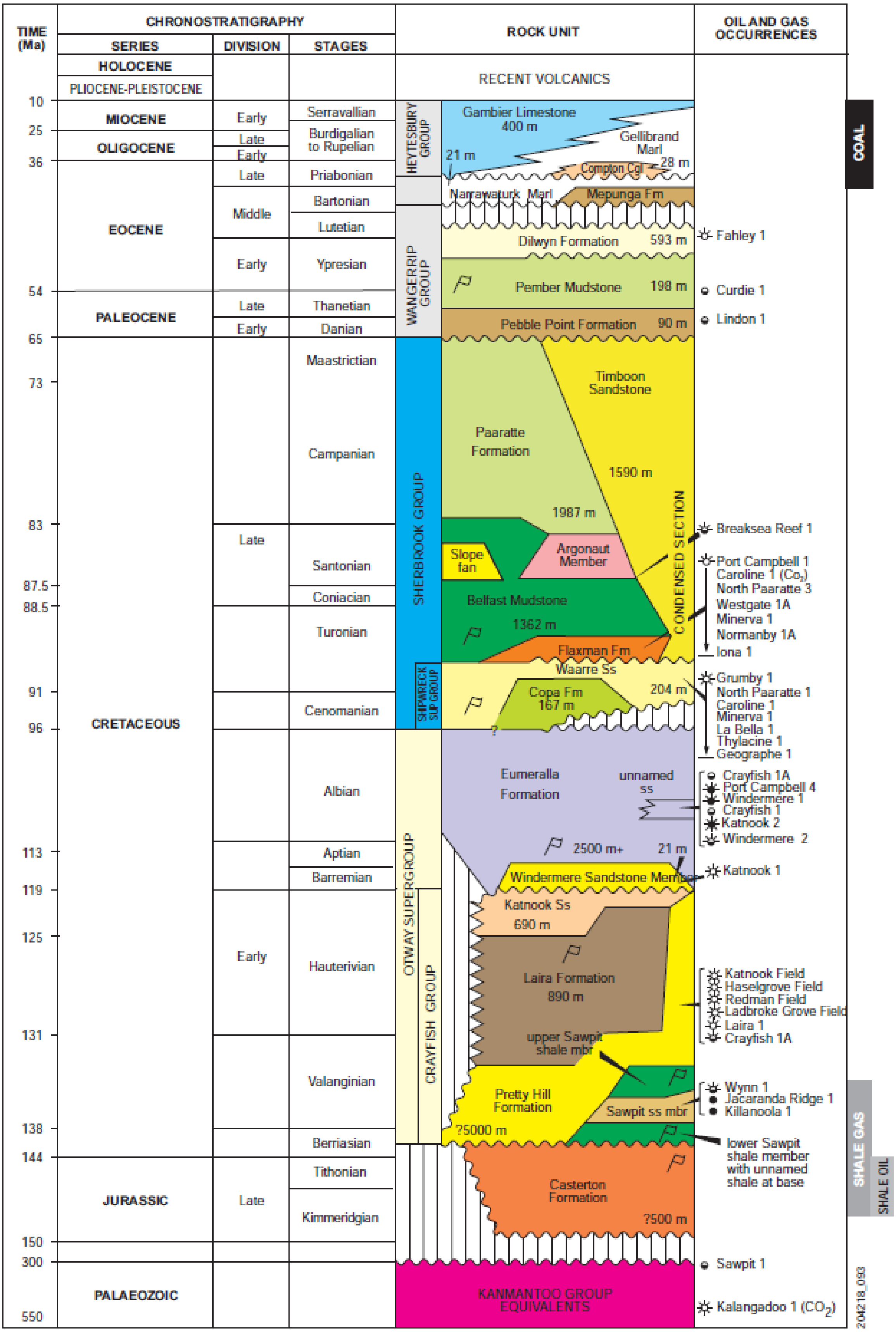

Figure C.71 Stratigraphic chart of the Otway Basin and petroleum discovery wells (from Goldstein et al., 2012)

C.9.2 Petroleum data coverage

The onshore Otway Basin has a long history of petroleum exploration. About 157 wells have been drilled in Victoria (Mehin and Kamel, 2002; Goldie Divko, 2015) and 113 in South Australia (Figure C.72; DPCSA, 2017a; GSV, 2017a). The majority of these wells targeted conventional petroleum in the Lower Cretaceous Otway Group and Upper Cretaceous Waarre Formation. There is about 30,000 line km of 2D seismic in the onshore part of the basin; 3D seismic surveys are concentrated in the western part of the basin and around Port Campbell (DPCSA, 2017c, c; GSV, 2009, 2017b).

There is complete coverage of gravity data across the basin with a station spacing varying, but usually of 4 km or less. In addition, the basin is covered by airborne magnetics data at line spacing of 400 m or less (Jorand et al., 2010). There is currently no production of conventional gas or CO_2 from ~30 small gas fields in the onshore part of the basin, except for Boggy Creek 1 CO_2 field, and ongoing production from large offshore conventional gas fields.

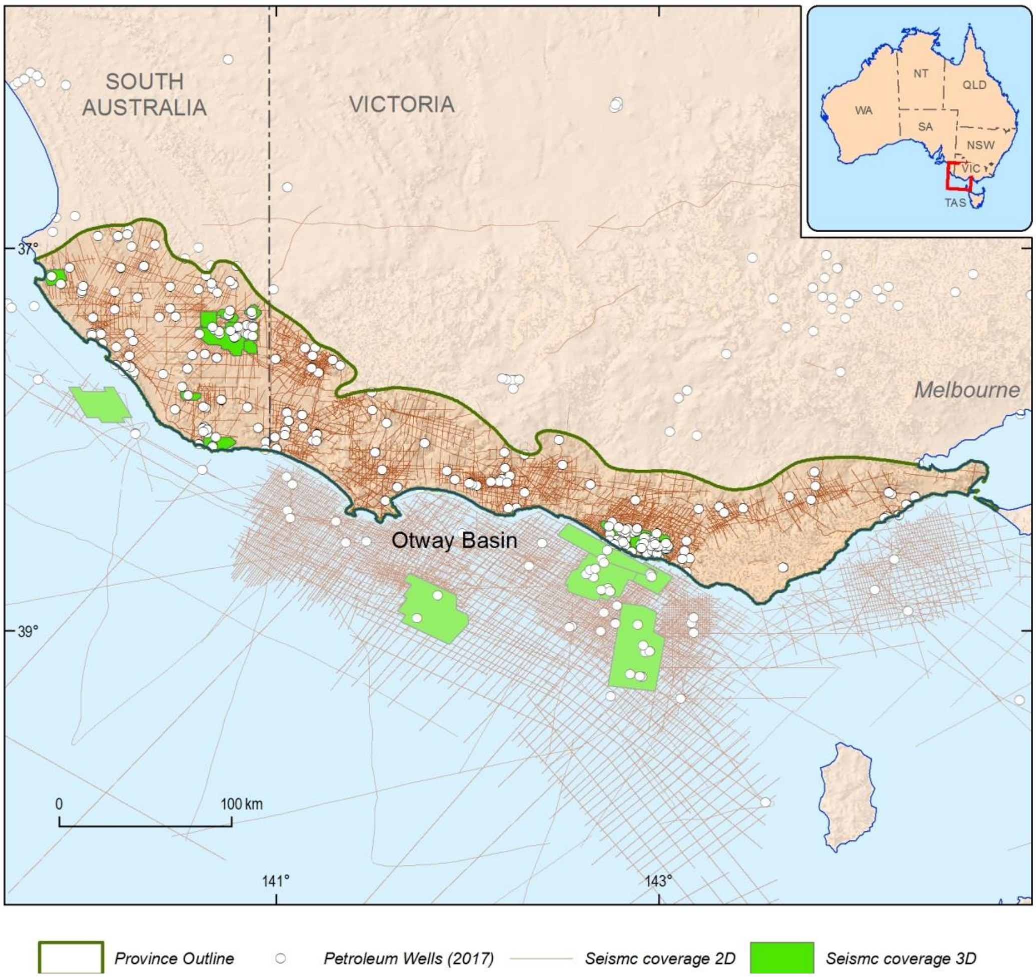

Figure C.72 Otway Basin petroleum exploration wells and seismic data coverage. Onshore basin outline from Stewart et al. (2013). Petroleum well data from DPCSA (2017a) and GSV (2017a). Seismic data coverage from DPCSA (2017c, d) and GSV (2009; 2017b).

C.9.3 Shale and tight gas prospectivity

The hydrocarbon prospectivity of the Otway Basin is summarised in Table C.61.

The Otway Basin is a well-established gas producing region, but discoveries have been confined to onshore and shallow water offshore areas of the basin; there has been relatively little unconventional exploration. From the late 1970s (particularly between 1986 and 2006), the Port Campbell Embayment and Penola Trough in South Australia were active onshore gas producing regions until the commercially viable gas was depleted (Goldie Divko 2015).

Natural gases and oils from the western Otway Basin have an Upper Jurassic–Lower Cretaceous Casterton Formation–Crayfish Group (Austral 1) source, compared to a Lower Cretaceous Eumeralla Formation (Austral 2) source for those from the eastern Otway Basin. Gases and oils in the central Otway Basin are, to varying degrees, the products of mixing from Crayfish and Eumeralla formation sources within local depocentres (Boreham et al., 2004; Edwards et al., 1999).

In the Otway Basin, the main tight and shale gas targets are within the Lower Cretaceous Otway Group in the lacustrine Casterton Formation, fluvio-lacustrine Crayfish Group and the fluvial intra-Eumeralla Formation (Jorand et al., 2010; Goldie Divko, 2015). Maturity modelling indicates that the Casterton Formation and Crayfish Group lie within the dry gas window at depths in excess of 3,800 m in the Penola and Robe troughs. Source rocks in the eastern Otway Basin are much more mature (dry gas window ~1,800 m) than their western Otway counterparts at similar depths due to higher erosion rates in the eastern part of the basin (Tassone et al., 2014). Drilling has shown that there is gas present within the Eumeralla Formation but commercial quantities of tight or shale gas are yet to be produced from the region.

The first test of a deeper unconventional play in the Western Otway Basin was carried out in 2014 by Beach Energy and Cooper Energy, who drilled two wells—Jolly 1 and Bungaloo 1 (Beach Energy, 2014; Cooper Energy, 2014); these wells followed up on encouraging gas shows in Sawpit 2 (Figure C.73; Cooper Energy, 2013). The two wells were drilled to a total depth of just over 4,000 m in the South Australian portion of the Penola Trough and confirmed the presence of two plays within the Crayfish Subgroup—an unconventional shale gas play in the Casterton Formation and an overlying conventional play in the “Sawpit Sandstone”.

Somerton Energy (now Cooper Energy) estimated that Victorian permit PEP 171 covering the eastern Penola Trough could contain more than 25 Tcf of shale gas in the Casterton Formation (Goldstein et al., 2012). The prospective shale units have yet to be fully penetrated in the centre of the Penola Trough so an understanding of gas saturation and likelihood of water drive is yet to be established (Goldstein et al., 2012).

AWT International (2013) has determined a best estimate recoverable tight gas resource of 9 Tcf of dry gas in the Eumeralla Formation over a prospective area of 4,109 km^2 (roughly between Portland and Port Campbell). In 2012, Moreys 1 encountered multiple tight gas sands with condensate in the Eumeralla Formation in the Port Campbell Embayment (Lakes Oil NL, 2016; Armour Energy, 2012). The resource has not been fully evaluated.

A recent volumetric study by Geoscience Australia based on publically available data assessed the undiscovered tight and shale gas resources of the Eumeralla Formation, Crayfish Subgroup and Casterton Formation. Results indicated total potentially recoverable gas-in-place resources of 5.8 Tcf of tight gas (maximum prospective area 17,233 km^2) and 1.6 Tcf of shale gas (prospective area wet gas 628 km^2; dry gas 369 km^2) (assuming a 5% recovery factor at P50; GA, 2017; AERA 2018). Analogues and geologically reasonable assumptions were used to characterise the Otway Basin shale and tight resource plays. In the medium term (10 to 15 years) only a small amount of the gas-in-place could be extracted because of the very early stage of exploration and the time needed to better define resources prior to production (AERA, 2018).

Data for the key unconventional hydrocarbon targets in the onshore Otway Basin are summarised in Table C.62.

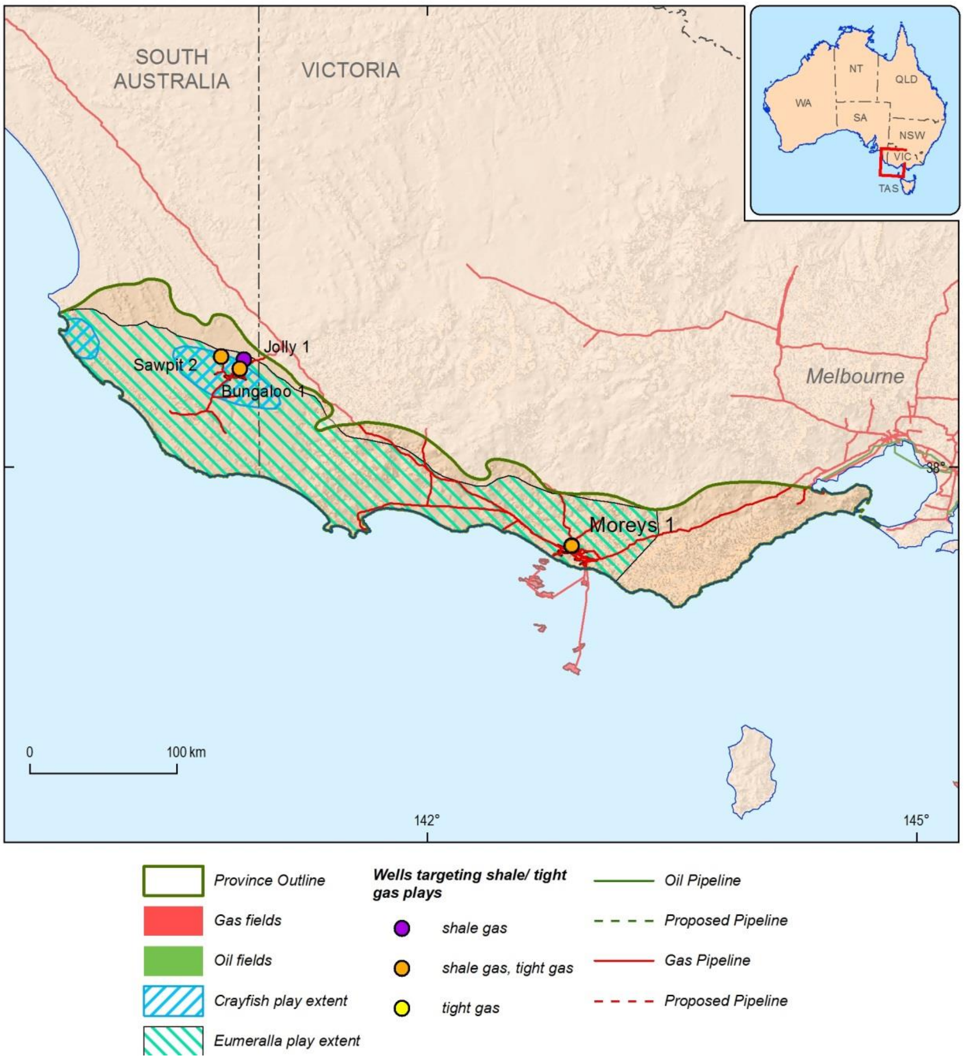

Figure C.73 Wells targeting shale or tight gas plays and approximate play extents modified from GA (2017). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

Table C.62 Summary of shale and tight gas plays.

Formation	Age	Environment	Top depth (m)	Thickness (m)	Source rocks(s)	Source rock TOC (%)	Source rock maturity (Rv)	Play type	Exploration status
Eumeralla Formation	Early Cretaceous	Fluvial–lacustrine	1,500	~2,000	Type II/III to Type III; coal, DOM (Austral 2)	0.1–67.5 (includes coal); average 5.73	Immature-dry gas; 0.2–2.5%	Tight gas	Preliminary exploration
Crayfish Subgroup	Early Cretaceous	Fluvial–lacustrine	1,700	3,500+	Type II/III to Type III; coal, DOM (Austral 2)	0.37–2.6	Immature-wet gas; 0.3–1.8%	Shale/tight gas	Preliminary exploration
Casterton Formation	Late Jurassic–Early Cretaceous	Lacustrine	2,500	45-500	Type II/III (Austral 1)	0.4–9	Immature-dry gas; 0.4–2.0%	Shale gas	Preliminary exploration

C.9.4 Gas market access and infrastructure

The offshore Otway Basin is a major supplier of gas to Australia's East Coast Gas Market. As a result, there is significant existing pipeline infrastructure in place across the basin, connecting the region to Adelaide and Melbourne (AER, 2017). The basin is very well serviced in terms of road and rail access.

Figure C.74 shows the location of major oil and gas infrastructure in the basin, including oil and gas pipelines and gas storage and processing facilities, along with the distribution of major road and rail networks. Further details are summarised in Table C.63.

Table C.63 Summary of market access and infrastructure. Pipeline information from AER (2017). Processing facilities from GA (2015b).

INFRASTRUCTURE	
Gas market	Currently supplies to the East Coast Gas Market
Gas pipelines	• SEA Gas Pipeline (Port Campbell to Adelaide) - capacity 314 TJ/ Day • Victorian Transmission System (GasNet) - capacity 1030 TJ/ Day
Gas processing facilities	Katnook; Otway; Heytesbury; Iona; Minerva
Approx. distance from existing pipelines to area prospective for shale and/or tight gas	<100 km
Road and rail access	Very well serviced
Approximate development timeframe	5–10 years

Figure C.74 Otway Basin petroleum fields, pipelines and production facilities. Basin outline from Stewart et al. (2013). Oil and gas infrastructure from GA (2015a). Processing facilities from GA (2015b). Field outlines are provided from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in compilation of the field outlines by PBS, no warranty is provided regarding the accuracy or completeness of the information. It is the responsibility of the customer to ensure, by independent means, that those parts of the information used by it are correct before any reliable is placed on them.

C.9.5 Regulatory environment impacting shale and tight gas exploration

All Australian states and territories have regulatory frameworks in place to manage impacts of petroleum exploration and production. In all Australian jurisdictions, companies intending to carry out drilling and stimulation operations must submit several applications to the relevant departments, including a drilling application, an environment plan and a safety management plan (APPEA, 2017).

Regulation is overseen by different government departments across Australia.

There is a permanent ban on onshore unconventional gas exploration and development in Victoria and a ban on hydraulic fracturing has been implemented in South Australia. Further details regarding regulatory environment for each state are summarised below.

C.9.5.1 South Australia

In April 2018, the South Australian Government implemented the 10-year moratorium on hydraulic fracturing in the southeast of the state effectively stopping exploration for unconventional gas in the Otway Basin.

C.9.5.2 Victoria

In March 2017, the Resources Legislation Amendment (Fracking Ban) Bill 2016 passed the Victorian Parliament (Victorian Government, 2017). This bill permanently bans all onshore unconventional gas exploration and development, including hydraulic fracturing and coal seam gas and extends the moratorium on conventional onshore gas exploration and development to 30 June 2020.

C.9.6 Hydrogeology and groundwater

C.9.6.1 Groundwater systems

A number of studies (Bush, 2009; Clark et al., 2015; DELWP and GSV, 2015) have detailed the geology and hydrogeology of the Otway Basin. This overview synthesises the existing knowledge of the hydrogeology of the Otway Basin.

The stratigraphic distribution of aquifers and aquitards in the Otway Basin succession is shown in Table C.64. There are two major and regionally extensive aquifer systems in the Otway Basin: these have been classified as the Upper Mid-Tertiary Aquifer (UMTA) and Lower Tertiary Aquifer (LTA) in the Victorian Aquifer Framework (GHD, 2012). These aquifers are used to extract large volumes of low salinity groundwater and are widely used for agriculture and town water supplies. Although the term 'Tertiary' is now obsolete and replaced with the use of 'Paleogene' and 'Neogene', this report retains the term 'Tertiary' as per its use in the reviewed literature and its use in the Victorian Aquifer Framework.

Upper Mid-Tertiary Aquifer (UMTA)

The UMTA system includes the Gambier Limestone in the Gambier Embayment in the western (mostly South Australian) part of the basin. Karst porosity is also extensive and well-developed in the Gambier Limestone, as well as excellent intergranular porosity. The Port Campbell Limestone, which is similar in age and composition to the Gambier Limestone and occurs in the central and eastern parts of the basin around Portland and Warrnambool in Victoria, is correlated as part of the same aquifer. At the regional scale, the UMTA is commonly the unconfined (water table) aquifer, although local variations mean that it may also be semi-confined by younger rock layers such as basalt flows of the Newer Volcanics Province.

Lower Tertiary Aquifer (LTA)

The LTA, commonly known as the confined sandy aquifer, is dominated by the Dilwyn Formation (Leonard, 2003). It consists mainly of sand and carbonaceous clay. The Dilwyn Formation is locally continuous with the overlying Mepunga Formation across the intra-Eocene disconformity, although the Mepunga Formation is of minor significance as a regional aquifer, and is normally included with the Dilwyn Formation.

Other Cenozoic aquifers

In some parts of the Otway Basin, groundwater is also extracted from relatively shallow aquifers associated with local to intermediate-scale flow systems. These include fractured and weathered basalts in the Newer Volcanics Province that forms the widespread the basalt plains of western Victoria. These local aquifers are generally interconnected with the UMTA and form the water table aquifer in most areas where present.

Table C.64 Hydrostratigraphy of the Otway Basin based on the Victorian Aquifer Framework (Source: Clarke et al., 2015).

Hydrostratigraphy of the Otway Basin

Era	Period	Epoch	Group	Hydrostratigraphic unit	VAF code	VAF number	Formation name	Depositional environment	Lithology	Maximum thickness
Cenozoic	Quaternary	Pleistocene		Quaternary Aquifer	QA	100	Molineaux Sand and Simpson Sand	Aeolian dune and interdunal alluvial	Unconsolidated, ferrugenous, medium to fine quartz sand, some calcareous and gypsiferous fragments, weakly modified by pedogenesis	5 m
							Padthaway Formation	Lacustrine, lagoonal, colluvial	Unconsolidated sand, silt, sandy clay, peat, marl and freshwater limestone	10 m
							Bridgewater Formation	Coastal barrier dunes, shallow sub-tidal, aeolian	Bioclastic, cross-bedded calcarenite, rich in silica and some heavy minerals, interbedded with palaeosols and capped by calcarenite	15 m
							Coomandook Formation	Intertidal, coastal	Partly lithified, grey,cream, fossiliferous, medium-grained quartz sand & calcareous sand; characteristically contains lithic clasts and skeletal debris derived from older limestone	75 m
				Upper Tertiary/ Quaternary Basalts	UTB	101	Newer Volcanic Group	Terrestrial, volcanic	Olivine basalt, ash, scoria, bombs, lapilli and calcareous fragments	100 m
	Neogene	Pilocene		Upper Tertiary Aquifer (marine)	UTAM	104	Whalers Bluff Formation	Coastal, shallow marine	Sandy limestone, calcarenite, shell beds, marl	130 m
							Parilla Sand	Aeolian lacustine, fluvial and marginal marine	Micaceous sand, quartz sand and sandy clay with some rare fossils	150 m
							Black Rock Sandstone	Marine-to-non-marine transition zone	Very course-grained quartz sand, calcareous sand, conglomerate, sand silt, clayey sand	10 m
		Miocene	Heytesbury Group	Upper Mid-Tertiary Aquifer	UMTA	107	Port Campbell Limestone	Deep marine	Weakly cemented calcarenite (limestone), fine grain, quartz rich, minor clayey silt	550 m
							Gambier Limestone (west)	Shallow marine shelf	Bioclastic, karstified, at times dolomitised limestone, rich in bryozoa and with basal glauconitic marl	400 m
				Upper Mid-Tertiary Aquitard	UMTD	108	Gellibrand Marl (east)	Deep marine (shallowing)	Calcareous silty clay and clayey silt, minor shelly calcarenite beds, strongly burrowed, massive	1300 m
	Paleogene	Oligocene		Lower Mid-Tertiary Aquifer	LMTA	109	Clifton Formation	Shallow marine	Glauconitic calcarenite (limestone), minor quartz and limonite sand, some beds well cemented	90 m
			Nirranda Group	Lower Mid-Tertiary Aquitard	LMTD	110	Narrawaturk Marl	Deep marine	Calcarenous mudstone, minor calcarenite, local calcareous and glauconite pellets	131 m
		Eocene					Mepunga Formation	Deep marine (shallowing)	Quartz sand, minor limonite and glauconite, localised cementation (calcite), otherwise unconsolidated. Alternating layers of carbonaceous clayey silt, including basal shale	380 m
				Lower Tertiary Basalts	LTB	112	Older Volcanic Group	Sills and dykes, subaerial volcanic	Olivine bearing gabbro and basalt, deeply weathered intrusions are clay-rich	200 m
			Wangerrip Group	Lower Tertiary Aquifer	LTA	111	Dilwyn Formation	Deep marine to shallow marine	Sandy clay, silt, carbonaceous, burrowed, quartz sand, minor gravel and shale, massive to moderately bedded	1000 m
		Paleocene		Lower Tertiary Basalts	LTB	112	Older Volcanic Group	Sills and dykes	Olivine bearing gabbro and basalt, deeply weathered intrusions are clay-rich.	
				Lower Tertiary Aquifer	LTA	111	Pember Mudstone Member	Deep marine to shallow marine	Silty clay, clayey silt, minor fine quartz sand, carbonaceous, limonitic, burrowed mudstone	200 m
							Pebble Point Formation	Deep marine to shallow marine	Dolomitic, quartz-rich sandstone, minor glauconite pellets, quartz pebbles,well bedded, interbedded with carbonaceous clay and basal mudstone	158 m
							Moomowroong Sand Member	Marine to non-marine transition	Quartz sand, minor clay, fine grained mica, friable, minor gravel	45 m
							Wiridjil Gravel	Non-marine	Quartz gravel, sand, minor pebble layers, minor clay, carbonaceous, friable, minor volcanic and metamorphic pebbles	70 m
Mesozoic	Cretaceous	Upper	Sherbrook Group				Timboon Sand	Marine transition zone	Quartz sand and gravel, carbonaceous mudstone, generally unconsolidated	1590 m
				Cretaceous and Permian Sediments	CPS	113	Paaratte Formation	Deep and shallow marine	Quartz sandstone, siltstone, mudstone, minor pebble beds, carbonaceous, minor glauconite	1987 m
							Nullawarre Greensand	Shallow marine	Quartz sandstone, glauconite pellets, weakly cemented, fine-to- coarse-grained	130 m
							Belfast Mudstone	Deep marine (shallowing)	Mudstone, carbonaceous, glauconitic, pyritic, minor quartz sand	1362 m
							Flaxman Formation	Deep marine (shallowing)	Siltstone, mudstone, sandstone, thin coal beds, quartz grains, ooliths, glauconite pellets, dolomite, siderite, minor phosphate, basal mudstone	620 m
							Waarre Formation	Deep marine to shallow marine to non-marine	Quartz sandstone, fine to coarse, interbedded with carbonaceous mudstone, minor coal, fine to coarse	636 m
		Lower	Otway Group	Cretaceous and Paleozoic Bedrock	BSE	114	Eumeralla Formation	Non-marine, fluvio-lacustrine, volcaniclastic, arkosic	Volcanolithic sandstone, siltstone, mudstone, mud clast conglomerate, feldspar, quartz, coal, consolidated, well bedded, medium to fine	2743 m
							Katnook Sandstone		Sandstone with minor, fossiliferous siltstone and coal	690 m
							Laira Formation		Shale, siltstone with minor fine-grained sandstone.	890 m
							Pretty Hill Formation		Quartz and feldspar sandstone, minor siltstone, mudstone and coal, medium to coarse, kaolinite, garnet, mica	5000 m
							Casterton Formation		Volcaniclastic sand and olivine basalt interbedded with minor sandstone, siltstone and shale	1000 m

13-7172-2

Mesozoic aquifers

The Mesozoic sedimentary rocks of the Otway Basin consist of the Upper Cretaceous Sherbrook Group and the Jurassic to Lower Cretaceous Otway Group.

The rocks of the Upper Cretaceous Sherbrook Group unconformably overlie the Otway Group. In descending order, the Sherbrook Group consists of the Timboon Sand (which is also included as the basal unit of the LTA aquifer), Paaratte Formation, the Nullawarre Greensand/Belfast

Mudstone/Mt Salt Formations, Flaxman Formation, and Waarre Formation (see Table C.64). Yield, porosity and permeability data is sparse for the rocks of the Sherbrook Group, although the Timboon, Paaratte, Flaxman and Waarre may all function as aquifers (Bush, 2009). However, only the Timboon Sand and the Paaratte Formation contain significant groundwater resources that are currently extracted in the basin. These aquifers are often separated by aquitards such as the Belfast Mudstone and Mount Salt Formation, which are lower confining aquitards of the Paaratte aquifer and the Flaxman Formation (Table C.64).

The main aquifers of the Otway Group, in descending order, are the Pretty Hill and Laira Formations, Katnook Sandstone (in the Penola Sub-basin), and Casterton Formation (see Table C.64). In other areas, the Katnook Sandstone and Laira Formation are treated as aquitards and, like the Eumeralla Formation, provide a confining layer over the Pretty Hill aquifer.

C.9.6.2 Groundwater quality

In the UMTA, groundwater salinity ranges from 500 to 7,000 mg/L total dissolved solids (TDS), but mostly less than 1,500 mg/L TDS, making it suitable for many uses (Leonard, 2003). The UMTA is the most commonly targeted aquifer in the Otway Basin, due to its relatively shallow nature, high yields and good quality groundwater. Groundwater in the Port Campbell aquifer (UMTA) has higher salinity than the underlying Dilwyn Formation aquifer (de Caritat et al., 2012)

Groundwater salinity in the LTA increases from less than 500 mg/L TDS in the recharge areas along the basin margins, to about 1000 mg/L TDS near the coast (Leonard, 2003). Near Warrnambool the salinity has a maximum TDS concentration of 5600 mg/L.

Groundwater quality data for the Mesozoic aquifers are very limited. Existing data is mainly derived from petroleum exploration wells and may be of low reliability. In general, higher salinity groundwater (>10,000 mg/L TDS) is found in the Upper Cretaceous Sherbrook Group and the Jurassic to Lower Cretaceous Otway Group.

C.9.6.3 Groundwater flow

Groundwater flow is controlled by the basin topography, with general flow in a south to southwesterly direction, towards the ocean (Figure C.75). The groundwater flow systems approach undertaken by Dahlhaus et al. (2002a, b) supports the data from other studies (e.g. Bush, 2009; SKM, 2009) which shows that regional flow systems exist in the Upper Mid-Tertiary Aquifer and Lower Tertiary Aquifer, and only local flow systems occur within the Lower Cretaceous rocks in near-surface environments.

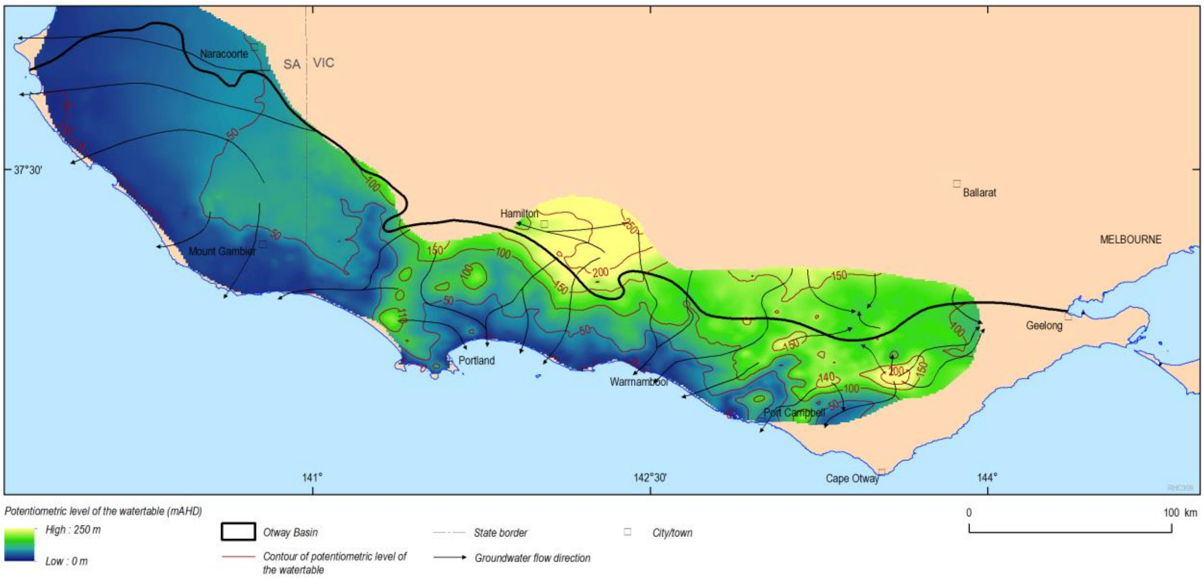

Figure C.75 Depth to water table in the Otway Basin, and regional groundwater flow lines (Source: Clarke et al., 2015).

C.9.6.4 Groundwater planning and use

Groundwater is managed within groundwater management units (GMUs) in the Otway Basin. There are about 16 GMUs in the Victorian portion of the basin and only one in South Australia, the Lower Limestone Coast Prescribed Wells Area (PWA). The Victorian GMUs are divided into two types, the Groundwater Management Areas (GMAs) and Water Supply Protection Areas (WSPAs), which have different rules for managing water resources.

Groundwater in the Otway Basin is used for irrigation, salinity control, stock and domestic, urban and power generation purposes. The Lower Limestone Coast PWA in South Australia has the greatest volume of groundwater extraction in the Otway Basin, with nearly 160,000 ML during 2010–2011. In comparison, there are only three GMUs (Glenelg WSPA, Nullawarre WSPA and Gerangamete GMA) in Victoria where the annual extraction exceeded 10,000 ML in the same period.

Table C.65 below presents information from the National Groundwater Information System (BoM, 2016) showing summary information of registered bores in the basin.

Table C.65 Summary of groundwater bores and level of groundwater and surface water developments.

GROUNDWATER BORES AND WATER USE		
Number of bores (Density of Registered Bores - bores/km^2)	51,458 (1.94)	
Purposes of registered bores (Top 5, number)	Stock	18,540
	Unknown	11,225
	Domestic Household	7,308
	Irrigated Agriculture	6,089
	Exploration	3,342
Depth (m) of registered bores below ground level (10th and 90th Percentile and median)	10th Percentile: 6.7 Median: 19.6 90th Percentile: 122	

C.9.7 Surface water hydrology

C.9.7.1 Surface water systems

There are eight river regions in the Otway Basin according to the Bureau of Meteorology Geofabric dataset (BoM, 2014). These are presented in Figure B.19 and include substantial portions and most of the coastline of the Millicent Coast, Glenelg River, Portland Coast, Hopkins River, Otway Coast, and Barwon River–Lake Corangamite catchments, as well as small portions of the Moorabool River region in the suburbs of Geelong and the Bunyip River region at Point Nepean. Connected drainage systems that flow dominantly south to south-west towards Bass Strait are typical of most river systems in the Victorian part of the Otway Basin, except for the eastern part of the Barwon River–Lake Corangamite system which empties into Port Phillip Bay. There are no permanent river systems in the South Australian part of the Otway Basin, due to the extensive near-surface limestone cover across this region.

C.9.7.2 Surface water quality

A number of river reaches were tested regularly for various water quality parameters in the Otway Basin; however there is not a complete coverage. Water quality tested at 24 of the 138 river reaches across the Corangamite River region ranged from excellent (7%) to poor (35%), with almost half (45%) of the assessed reaches in moderate condition and 13% in good condition based on salinity and turbidity. Water quality in the Moorabool, Barwon and Corangamite catchments was generally moderate, despite the heavily modified environment. Many of the sites assessed had elevated levels of phosphorus.

C.9.7.3 Surface water flow

The level of information available on streamflow varies between rivers in the Otway Basin. Rivers where regulation for water supply has had effects on their ecology have had some studies into hydrology as well as surface-water quality conducted. The Glenelg River has a high flow season during July–October, and previously experienced cease-to-flow at times in February to April; however, due to regulation, this pattern has evened out somewhat, although some seasonality remains. The annual streamflow since building the Rocklands Reservoir has decreased from 113,000 ML/yr to 43,000 ML/yr, by reducing the frequency of large flushing flows in late winter (Glenelg Hopkins CMA, 2016).

The Barwon River streamflow is seasonal: maximum flows occur during August–September, while very low flows occur during December–April, when the river declines to baseflow. Some 60% of annual flow occurs from July to September, while only 5% occurs from January to March. Annual discharge increases downstream, but this has been altered by the dams and diversions; the Barwon is a major source of supply for Geelong and other centres as well as agriculture. Some summer cease-to-flow days occur in the upper catchment, but not in the lower catchment. The streamflow is being managed by Corangamite Catchment Management Authority so that sufficient flow variation and quantity is maintained to support ecological targets. The median summer baseflow on the lower Barwon River is 43 ML/day (Corangamite CMA, 2005).

C.9.7.4 Surface water planning and use

Surface water in the basin is used for irrigation, stock and domestic, urban, commercial and power generation purposes. Irrigation accounted for 79% of consumptive use in 2014–2015 (DELWP, 2016). Urban and commercial use accounted for 15% of consumptive use for the period, and domestic and stock and power generation accounted for 4% and 2%, respectively. The majority of surface water entitlements and usage occur in the Otway Coast, Barwon and Moorabool catchments.

C.9.8 Groundwater – surface water interactions

Connectivity exists between the shallow aquifers and surface water in a number of river reaches across the Otway Basin. GHD (2014) calculated the baseflow contributions to streamflow, and the gaining and losing nature of a number of rivers and streams in the Otway Basin. These results show that the Barwon River transitions from generally losing in the upland river reaches to gaining through the mid-reaches, and variably gaining and losing throughout its lower reaches. The lower Glenelg and Gellibrand rivers are generally gaining rivers and the lower Hopkins River is variably gaining and losing. The proportion of baseflow throughout western Victoria in the Barwon, Gellibrand, Glenelg and Hopkins river catchments ranges from 26 to 34%.

C.9.9 Environmental assets

Within the Otway Basin there are 505 km^2 of Listed Nationally Important Wetlands, 1,500 km^2 of Groundwater Dependant Ecosystems (of at least moderate potential) and a number of Ramsar wetlands. A total of 2963 km^2 of protected areas (such as national parks) are listed (Table C.66).

Table C.66 Summary of environmental assets.

Environmental Assets		
Ramsar Wetlands	Western District Lakes	
	Port Phillip Bay (Western Shoreline) and Bellarine Peninsula - Lake Connewarre	
	Bool and Hacks Lagoons	
	Piccaninnie Ponds Karst Wetlands	
	Port Phillip Bay (Western Shoreline) and Bellarine Peninsula - Swan Bay	
Nationally Important Wetlands Top 5 by area (area km^2)	South East Coastal Salt Lakes	148
	Lake Corangamite	51
	Mundi-Selkirk Wetlands	41
	Lake Connewarre State Wildlife Reserve	36
	Bool and Hacks Lagoon	32
	TOTAL WETLAND AREA	505
Protected areas (CAPAD 2016) Top 5 by area (area km^2)	National Park	1,748
	Conservation Park	263
	Natural Features Reserve	223
	Marine National Park	185
	Forest Reserve	113
	TOTAL PROTECTED AREA	2,963
Aquatic and Terrestrial Groundwater Dependant Ecosystems, of known, high potential and moderate potential (area km^2).	1,500	

C.9.10 Social considerations

Information on population, land use type and areas listed as either Indigenous Protected Areas (CAPAD, 2016) or where Native Title exists is presented in Table C.67.

Table C.67 Summary of population, land use and aboriginal protected area.

GENERAL CHARACTERISTICS		
Population	358,407	
Major population centres (Top two)	Geelong, Mt Gambier	
Land use types Top 5 by area (area km^2)	Grazing modified pastures	13,833
	Plantation forestry	4,883
	Nature Conservation	2,590
	Urban intensive uses	990
	Dryland cropping	938
Aboriginal Protected Area (CAPAD 2016) and Native title (area km^2)	1,366	

Key references

AER (Australian Energy Regulator) (2017) State of the energy market, May 2017. Viewed 16/01/2018, <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-may-2017>.

APPEA (2017) Shale gas in Australia. Viewed 15/01/2018, <https://www.shale-gas.com.au/environment/regulation-and-licensing/>.

Armour Energy (2012) Moreys 1 encounters tight gas and condensate. Armour Energy report to ASX. Viewed 22/01/2018, <http://www.asx.com.au/asxpdf/20120510/pdf/4265z4bqyh37mz.pdf>.

AWT International (2013) Shale Gas Prospectivity Potential Report prepared for the Australian Council of Learned Academies (ACOLA) 54 p.

Beach Energy (2014) Beach completes Otway basin well. Beach Energy media release. Viewed 22/01/2018, <http://www.beachenergy.com.au/irm/PDF/3361_0/BeachcompletesOtwayBasinwell>.

Boreham CJ, Hope JM, Jackson P, Davenport R, Earl KL, Edwards DS, Logan GA and Krassay AA (2004) Gas-oil-source correlations in the Otway Basin, southern Australia. In: Boult PJ, Johns DR and Lang SC (eds), Eastern Australasian Basins Symposium II. Petroleum Exploration Society of Australia, Special Publication, 603–627.

Boult PJ and Hibburt JE (eds) (2002) The petroleum geology of South Australia. Vol. 1: Otway Basin. 2nd edition. South Australia. Department of Primary Industries and Resources. Petroleum Geology of South Australia Series, Vol. 1.

BoM (Bureau of Meteorology) (2014) Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1. Viewed 02/08/2017, <http://www.bom.gov.au/water/geofabric/download.shtml>.

BoM (Bureau of Meteorology) (2016) National Groundwater Information System, v.1.3. Viewed 07/07/2017, <http://www.bom.gov.au/water/groundwater/ngis/>.

Bush AL (2009) Physical and chemical hydrogeology of the Otway Basin, southeast Australia. Unpublished PhD thesis, School of Earth Sciences, University of Melbourne.

CAPAD (2016) Collaborative Australian Protected Area Database (2016 Spatial dataset provided from the Department of the Environment and Energy. Viewed 18/07/2017, <https://www.environment.gov.au/land/nrs/science/capad/2016>.

Clarke JDA, Lewis SJ, Fontaine K, Kilgour PL and Stewart G (2015) Regional Hydrogeological Characterisation of the Otway Basin, Victoria and South Australia: Technical report for the National Collaboration Framework Regional Hydrogeology Project. Record 2015/12. Geoscience Australia, Canberra.

Corangamite CMA (2005) The Environmental Flow Determination for the Barwon River – Issues Paper, August 2005. Viewed 17/08/2017, <www.yoursay.barwonwater.vic.gov.au/27010/documents/60176>.

Core (2014) Gas reserves and resources, eastern and southeastern Australia. Core Energy Group report to the Australian Energy Market Operator. Viewed 09/08/2017, <https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2015/Core--Gas-Reserves-and-Resources.pdf>.

Cooper Energy (2013) Sawpit-2 results. Armour Energy report to ASX. Viewed 22/01/2018, <http://www.cooperenergy.com.au/archive/images/files/2013/2013_03_06_Sawpit-2_Update.pdf>.

Cooper Energy (2014) Bungaloo-1 spudded in Penola Trough, Otway Basin. Cooper Energy ASX Announcement/Media release. Viewed 22/01/2018, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Bungaloo-1-spudded-in-Penola-Trough,-Otway-Basin.pdf>.

Dahlhaus P, Heislers D and Dyson P (2002a) Corangamite Catchment Management Authority Groundwater Flow Systems.

Dahlhaus P, Heislers D and Dyson P (2002b) Glenelg-Hopkins Catchment Management Authority Groundwater Flow Systems.

De Caritat P, Hortle A, Raistrick M, Stalvies C and Jenkins C (2012) Monitoring groundwater flow and chemical and isotopic composition at a demonstration site for carbon dioxide storage in a depleted natural gas reservoir, Applied Geochemistry, 30, p.16-32.

DELWP (Department of Environment, Land, Water and Planning) and GSV (Geological Survey of Victoria) (2015a) Onshore natural gas water science studies — Otway region assessment of potential impacts on water resources. Department of Environment, Land, Water and Planning and Department of Economic Development, Jobs, Transport and Resources, Melbourne, June 2015.

DELWP (Department of Environment, Land, Water and Planning) (2016) Victorian Water Accounts 2014-15 – A statement of Victorian water resources. Department of Environment, Land, Water & Planning, Victoria.

DPCSA (Department of Premier and Cabinet, South Australia) (2017a) 3D Seismic Survey Areas lines. Viewed 23/07/2017, <https://map.sarig.sa.gov.au/>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017b) PACE Gas. Viewed 16/01/2018, <http://petroleum.statedevelopment.sa.gov.au/latest_updates/pace_gas>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017c) Petroleum well. Viewed 16/01/2018, <https://map.sarig.sa.gov.au/>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017d) Seismic lines. Viewed 16/01/2018, <https://map.sarig.sa.gov.au/>.

DPCSA (Department of Premier and Cabinet, South Australia) (2017e). South Australia Otway Basin Acreage Release OT2017-A. Viewed 16/01/2018, <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PEDP012BROCHURE.pdf>

Edwards DS, Struckmeyer HIM, Bradshaw MT and Skinner JE (1999) Geochemical characteristics of Australia's southern margin petroleum systems. The APPEA Journal, 39(1), 297–321.

GA (Geoscience Australia) (2015a) Oil and Gas Infrastructure. Viewed 16/01/2018, <http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer>.

GA (Geoscience Australia) (2015b) Oil and Gas platforms. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6>.

GA (Geoscience Australia) (2017) Interim Otway Basin unconventional resource assessment. Viewed 16/01/2018, <http://www.ga.gov.au/metadata-gateway/metadata/record/104440>.

GHD (2012) Victorian Aquifer Framework: Updates for Seamless Mapping of Aquifer Surfaces. Report prepared for the Victorian Department of Sustainability and Environment, May 2012.

Glenelg Hopkins CMA (2016) Glenelg River Environmental Water Management Plan 2016. Viewed 17/08/2017, <http://www.vewh.vic.gov.au/__data/assets/pdf_file/0004/357529/Glenelg-River-EWMP-FINAL-reduced-size.pdf>.

Goldie Divko LM (2015) A review of gas prospectivity: Gippsland region. Department of Economic Development, Jobs, Transport and Resources. Melbourne, Victoria.

Goldstein B, Menpes S, Hill A, Wickham A, Alexander E, Jarosz M, Pepicelli D, Malavazos M, Staritski K, Taliangis P, Coda J, Hill D and Webb M (2012) Roadmap for Unconventional Gas Projects in South Australia. Department for Manufacturing, Innovation, Trade, Resources and Energy, 267p. Viewed 18/01/2018, <https://statedevelopment.sa.gov.au/resourcesUNPUBLISHED/unconventional-gas-projects>.

GSV (Geological Survey Victoria) (2009) The polygons depict the outline of 3D surveys. These outlines illustrate the survey outlines but are not consistently defined. Viewed 11/08/2017, http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002766&extractionProviderId=1>.

GSV (Geological Survey Victoria) (2017a) Seismic Survey Lines - for Petroleum Industry Exploration. Viewed 1/08/2017, <https://www.data.vic.gov.au/data/dataset/seismic-survey-lines-for-petroleum-industry-exploration>.

GSV (Geological Survey Victoria) (2017b) Petroleum Wells (from Minerals and Petroleum's DbMap database) Viewed 11/08/2017, <http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002954&extractionProviderId=1>.

Jorand C Krassay A and Hall L (2010) Otway Basin Hot Sedimentary Aquifers and SEEBASE Project. Department of Primary Industries and Resources, South Australia. Report Book 2010/00010. Viewed 18/01/2018, <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/RB201000010.pdf>

Krassay AA, Cathro DL and Ryan DJ (2004) A regional tectonostratigraphic framework for the Otway Basin. In: Boult PJ, Johns DR and Lang SC (eds), Eastern Australasian Basins Symposium II. Petroleum Exploration Society of Australia, Special Publication, 97–116.

Lakes Oil NL (2016) Annual report 30 June 2016. Viewed 18/01/2018, <http://lakesoil.net.au/announcements/announcements-2016/>.

Leonard JG (2003) Groundwater, In: Birch WD (ed.), Geology of Victoria, Geological Society of Australia, p. 521-531

Mehin K and Kamel M (2002) Gas Resources of the Otway Basin in Victoria. Department of Natural Resources and Environment.

Raymond OL, Gallagher R and Highet LM (2012) Surface geology of Australia, 1:2 500 00 scale, 2012 edition. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!b4088aa1-f875-2444-e044-00144fdd4fa6>.

SKM (2009) Hydrogeological Mapping of Southern Victoria. SKM consulting, unpublished report for Southern Rural Water (Victoria).

Stewart AJ, Raymond OL, Totterdell JM, Zhang W and Gallagher R (2013) Australian Geological Provinces, 2013.01 edition, scale 1:2 500 000. Geoscience Australia, Canberra. Viewed 16/01/2018, <https://ecat.ga.gov.au/geonetwork/srv/eng/search#!2680f4bb-8494-14fc-e053-10a3070a4107>.

Tassone DR, Holford SP, Duddy IR, Green PF and Hillis RR (2014) Quantifying Cretaceous–Cenozoic exhumation in the Otway Basin, southeastern Australia, using sonic transit time data: Implications for conventional and unconventional hydrocarbon prospectivity. AAPG Bulletin, 98(1), 67–117.

Victorian Government (2017) Media release March 2017. Viewed 16/01/2018, <http://www.premier.vic.gov.au/fracking-banned-in-victoria-giving-certainty-to-farmers/>.

www.bioregionalassessments.gov.au