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 Assessments Program: Stage 1

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

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Executive summary

In May 2017, the Australian Government announced a new Geological and Bioregional Assessments Program to be conducted in three onshore areas that are underexplored but prospective for shale and tight gas. 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 tight and shale gas development (https://bioregionalassessments.gov.au/geological-and-bioregional-assessment-program).

The Geological and Bioregional Assessments Program has the following objectives:

- encourage exploration to bring new shale and tight gas resources to the East Coast Gas Market within the next five to ten years;
- increase the understanding of the potential impacts on water and the environment posed by shale and tight gas development, and identification of robust monitoring and management practices to support the industry;
- increase the efficiency of assessment and ongoing regulation, including through advancing robust assessment material aligning with Commonwealth EPBC Act and State approval processes, and improved reporting and data provision/management approaches, and;
- improve community understanding of the industry.

Geoscience Australia (GA) and CSIRO are conducting the assessments. The program is managed by the Department of the Environment and Energy (DoEE) and supported by the Bureau of Meteorology (BoM).

Stage 1 of the program, conducted by GA, uses a rapid regional prioritisation process to identify the basins with the greatest potential for shale and tight gas development, in eastern and northern Australia, within the next five to ten years. This report presents the context of the program and describes the evidence based decision making process used in Stage 1 to narrow the focus of the Geological and Bioregional Assessments Program to areas of highest priority for further research.

Method

The rapid regional prioritisation methodology was designed by Geoscience Australia (GA) to assist the DoEE in identifying priority areas for further research.

Shortlist of basins with shale and/or tight gas prospectivity

An initial shortlist of Australian sedimentary basins capable of supplying significant volumes of shale and/or tight gas to the East Coast Gas Market in the next five to ten years was identified. Basins were selected using the following screening criteria:

- proximity to eastern or Northern Territory gas market infrastructure;

- active industry exploration for shale and/or tight gas resources and;
- documented contingent (2C) and/or prospective shale and/or tight gas resources.

Regions where shale and tight gas exploration is currently occurring – or is likely to occur in the near future – were considered priority areas for early research. The results of the shortlisting process are described in Section 5.1 of this report and the full review of shale and tight gas resources and exploration activity for eastern and northern Australia can be found Appendix A.

Data inventory

A review was conducted of open file petroleum data and national scale, environmental and cultural data relevant to each shortlisted basin. Regional scale data were included, if national scale datasets were unavailable. Datasets from the original Bioregional Assessment Program were reviewed and updated to ensure currency. Datasets relevant to the geology and shale and tight gas prospectivity of each shortlisted basin were also added, including those with the themes of geological provinces, petroleum wells, 2D seismic navigation data, 3D seismic data coverage, oil and gas fields, oil and gas pipelines and other relevant infrastructure. Further details of the data inventory are described in Section 5.2 of this report, and the associated national scale maps are presented in Appendix B.

Audit of shortlisted basins

The data inventory and associated literature were used to underpin a rapid audit of each shortlisted basin. Each basin audit was conducted based on the following rapid regional prioritisation criteria: basin geology, resources, market access, infrastructure, regulatory environment, environmental constraints and social factors/constraints. This process aimed to:

- capture the current state of knowledge of each basin's shale and tight gas prospectivity, and;
- identify the water resources and environmental assets in each basin that could potentially be utilised and/or be affected by shale and tight gas extraction.

The results are presented in Section 5.3 of this report, and within the basin summary documents in Appendix C.

Results

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

- 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 investment and no other impediment to development (e.g. regulatory restrictions; environmental or social concerns), the potential development timeframes for key plays within these basins was considered to be ten years or less, and hence these basins were shortlisted as priority areas for further research.

Shale and tight gas prospectivity and confidence

The results of the basin audit were used to assign a ‘shale and tight gas prospectivity’ ranking and a ‘confidence’ ranking to each basin. Both rankings are qualitative and are based on the level of knowledge and available data for the given basin (Figure 0-1). Key factors considered in assessing the ‘shale and tight gas prospectivity’ ranking included:

- overall petroleum prospectivity;
- estimated prospective resource area which may reasonably be developed in a ten year timeframe (where such information was available from existing public domain sources);
- prospective resources, and;
- shale and/or tight gas exploration success to date.

The ‘confidence’ rankings are based on both the amount of data available within the basin and the quality of that data. They were assessed on the number of petroleum wells and shale/ tight gas wells drilled to date, line kilometres of seismic data and shale/ tight gas exploration status. Lower data quantity and/or quality resulted in a lower confidence for the prospectivity ranking, whereas a high confidence was used to indicate the ‘shale and tight gas prospectivity’ rating is more informed.

From this assessment:

- The Cooper Basin is ranked highest in terms of both prospectivity and confidence, reflecting the extensive exploration of both conventional and unconventional plays already undertaken in this basin and the exploration success to date.
- The shale and/or tight gas prospectivity of the McArthur, Bowen and Amadeus basins rank as high, based on the quality of known and potential source rocks, while confidence is only moderate reflecting the basins’ more limited exploration history.
- The Otway Basin ranks as moderate–high prospectivity and high confidence due to data density and quality.
- The Isa Superbasin prospectivity ranks as moderate–high due to the booked contingent resources, however confidence is low–moderate due to sparse data distribution and very limited exploration history.
- The Gippsland Basin is ranked moderate for prospectivity based on the relatively small area in which unconventional gas resources may be developed within a 10 year timeframe, however confidence is high due to data density and quality.

- The Georgina Basin is ranked as moderate in terms of prospectivity, reflecting the relatively poor results of recent exploration, with a low–moderate confidence reflecting sparse data distribution.
- The Clarence-Moreton Basin is ranked as low–moderate for both prospectivity and confidence, reflecting the relatively small prospective area, early stage of exploration and limited data.

Both 'shale and tight gas prospectivity' and 'confidence' rankings could be improved with more data collection and by conducting further studies.

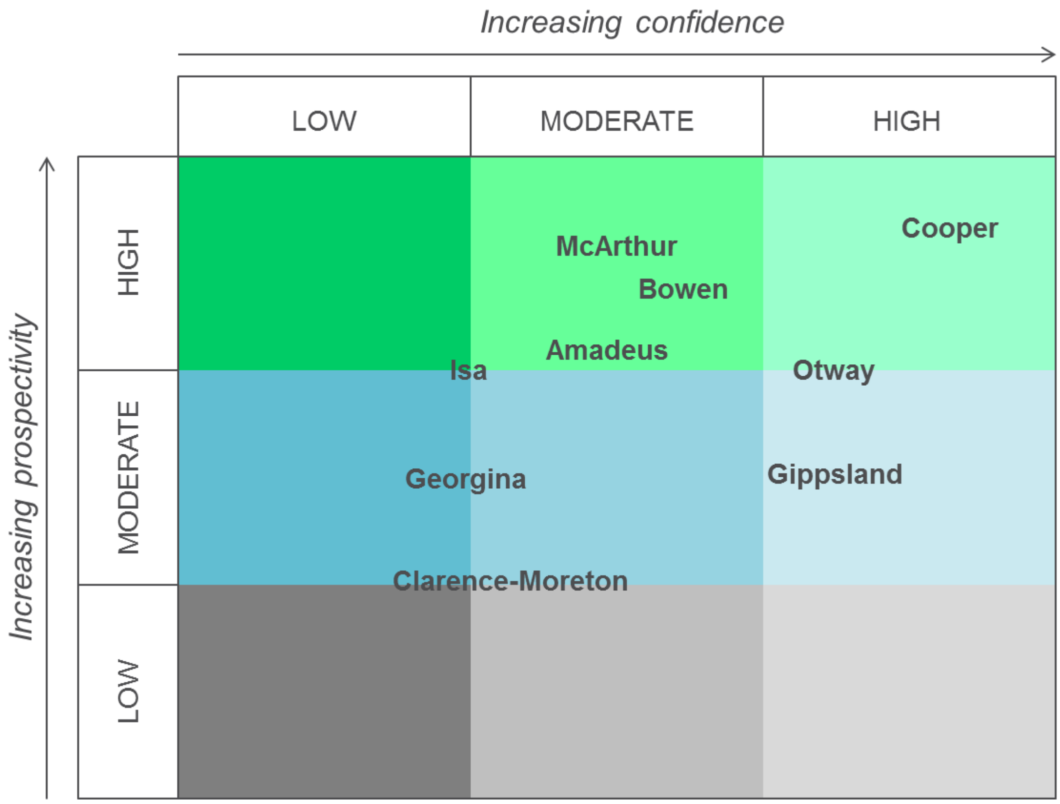

Figure 0-1 Shale/ tight gas prospectivity-confidence matrix for shortlisted basins.

Proximity to market and access to infrastructure

In assessing proximity to the East Coast Gas Market, those basins already producing gas directly into the East Coast Gas Market infrastructure were ranked highest. The Northern Gas Pipeline, scheduled to open by the end of 2018 (Jemena, 2017), will allow gas from basins connected to the Northern Territory Gas Market to be provided to the East Coast Gas Market. However, the pipeline has limited capacity (90 TJ/day), and distance from the customer affects transport costs, although transport and transmission costs are not a consideration of the prioritisation.

The factors considered in assessing access to infrastructure were proximity to existing oil and gas pipelines, additional infrastructure requirements, availability of processing and storage facilities, road and rail access and proximity to townships. A qualitative ranking was applied to each basin regarding access to infrastructure, based on the level of knowledge and available data for the given basin.

From this assessment:

- The Cooper, Bowen, Otway and Gippsland basins all have significant existing infrastructure in place connecting them with the East Coast Gas Market including pipelines and gas processing facilities. All regions are well serviced in terms of road and rail, with proximity to townships.
- The Amadeus and McArthur basins contain existing pipeline infrastructure connecting them with the Northern Territory Gas market, but development of any shale or tight gas plays away from the producing fields would require significant further investment.
- Development of shale or tight gas plays in the Clarence-Moreton Basin would require additional infrastructure development as the prospective area is over 100 km from the existing East Coast Gas Market pipeline network.
- Development of shale or tight gas plays in the Georgina Basin and Isa Superbasin would require major additional infrastructure development. There are currently no gas processing facilities and the prospective areas in both basins lie over 200 km from existing pipeline infrastructure. Both basins are only poorly to moderately well serviced by road and rail, and are sparsely populated with few townships.

These rankings are intended as a relative guide to market access at a whole of basin scale and should not be applied to any individual play. Significant additional analysis would be required to determine additional infrastructure requirements at play, lead or prospect level.

Regulatory Environment

There are moratoria and other regulatory restrictions in New South Wales, Victoria and Tasmania that prevent or impede onshore gas exploration and development. In April 2018 the Northern Territory Government lifted the moratorium on hydraulic fracturing over 51% of the Territory. The South Australian Government have placed a 10 year moratorium on hydraulic fracturing over the south-east of the state. Only Queensland has no current exploration and development restrictions. Western Australia does not contribute to the East Coast Gas Market and was therefore not considered.

Groundwater, surface water, environmental and social considerations

The basin audits provide information on a range of environmental and social factors that need to be considered as part of shale and tight gas development. Water is of key importance, both as a resource to enable hydraulic fracturing operations and as a resource for other users and water-dependent ecosystems that can be affected by the development of tight and shale gas. The environmental datasets examined in this report include those with information on principal aquifer types, registered groundwater bores (from the National Groundwater Information System) and groundwater dependant ecosystems, wetlands and protected areas (such as national parks). Population, land use types and Indigenous Protected Areas (including areas of native title) within the basins' area were included as social factors. National-scale datasets were utilised to enable basin-to-basin comparisons.

Principal aquifer productivity from national-scale data ranges from low-moderate (Clarence-Moreton Basin) to highly productive aquifers in the Amadeus, Bowen, Cooper, Georgina, McArthur, Gippsland and Otway basins.

All basins have both groundwater dependant ecosystems (GDEs) and wetlands present. These areas are potentially sensitive to variations in the level of groundwater extraction. The Otway and Amadeus basins have the smallest GDE area, at 1,500km^2 and 1,600km^2 respectively, while the Bowen and Cooper basins have the largest GDE area coverages at 26,000 km^2 and 13,800 km^2 respectively. The basins with the lowest area of wetlands are the Amadeus and Clarence-Moreton basins with 50 km^2 and 300 km^2 respectively; while large areas of the Cooper Basin (16,200 km^2), Mount Isa Province (6,300 km^2) and McArthur Basin (5,400 km^2) contain environmentally significant wetlands.

The population within the basin assessed varied by four orders of magnitude, from 1,000,400 within the Clarence-Moreton Basin to 400 within Cooper Basin (ABS, 2016).

Outcomes

Basin geology, prospectivity, market access and regulatory environment

Basins most likely to deliver new shale and/or tight gas resources to market within five to ten years need to match the following criteria:

- high prospectivity for shale/ tight gas resources, and;
- moderate to high confidence is due to the level of data collected/ exploration status.

The Amadeus, Bowen, Cooper, Otway and McArthur basins, and Isa Superbasin, meet the above prioritisation criteria. The relatively small prospective areas of the Gippsland and Clarence-Moreton basins, and the poor exploration successes in the Georgina Basin, mean these basins fail to meet the prospectivity criteria.

Regulatory constraints, such as exploration or hydraulic fracturing moratoria, may prevent or significantly impede onshore gas exploration and development. Of the top ranked prospectivity basins, the Cooper and Bowen basins remain unaffected by current restrictions; along with the majority of the prospective area of the Isa Superbasin (located in Queensland). In April 2018 the Northern Territory Government lifted the moratorium on hydraulic fracturing for 51% of the Northern Territory. The Otway basin is impacted by moratorium on hydraulic fracturing in the south-east of South Australia and the on-going ban on hydraulic fracturing in Victoria, which also impacts the Gippsland basin.

Groundwater, surface water, environmental and social considerations

No prioritisation was undertaken with regard to groundwater, surface water, environmental and social considerations, as this requires subjective values to be placed on items that have a diverse range of values attached to them across the community (e.g. National Parks, existing groundwater use).

The national-scale data used in this assessment show that all basins, to greater or lesser degrees, have aquifers capable of supplying groundwater of varying quality. However, local and regional variations do this exist. The level of hydrogeological information – including groundwater systems understanding, groundwater quality, groundwater flow, and groundwater planning and use – varies widely between individual basins assessed. Furthermore, hydrogeological understanding decreases with depth.

The spatial distribution of other social and environmental factors shows a high level of variation between basins, which should be considered when selecting basins for Stage 2.

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The following individuals have contributed to the Stage 1 of the Geological and Bioregional Assessments Program.

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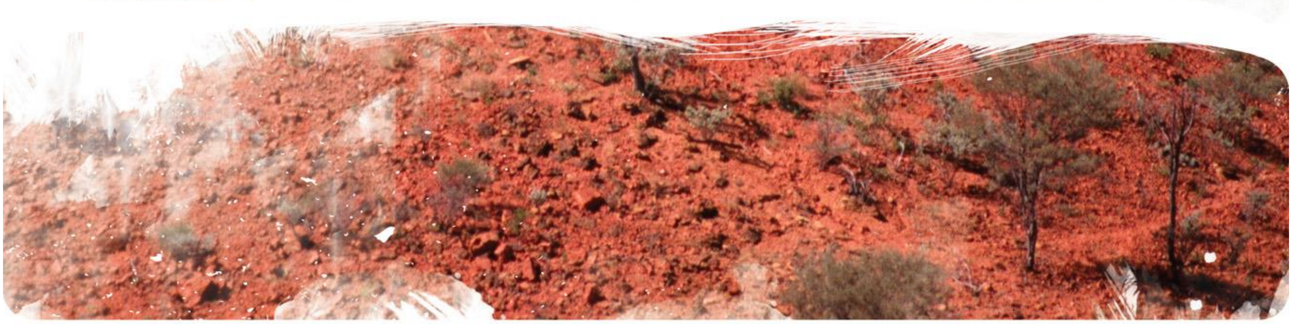
Valuable comments were also provided by Bridgette Lewis and Anthony Budd (Geoscience Australia).

Rapid regional basin prioritisation



1 Introduction

In May 2017, the Australian Government announced a new Geological and Bioregional Assessments Program to be conducted in three onshore areas that are underexplored but prospective for shale and tight gas. 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 tight and shale gas development (https://bioregionalassessments.gov.au/geological-and-bioregional-assessment-program).

The Geological and Bioregional Assessments Program has the following objectives:

- encourage exploration to bring new shale and tight gas resources to the East Coast Gas Market within the next five to ten years;
- increase the understanding of the potential impacts on water and the environment posed by shale and tight gas development, and identification of robust monitoring and management practices to support the industry;
- increase the efficiency of assessment and ongoing regulation, including through advancing robust assessment material aligning with Commonwealth EPBC Act and State approval processes, and improved reporting and data provision/management approaches, and;
- improve community understanding of the industry.

The Geological and Bioregional Assessments Program commenced in July 2017 and will be completed in three stages over a three to four year period, as described below.

- **Stage 1 Rapid Regional Basin Prioritisation:** A rapid regional prioritisation process will narrow the focus of the geological and bioregional resource assessments. After this assessment and consultation with state governments and industry, three basins will be chosen by the Australian Government for detailed study in Stage 2.
- **Stage 2 Geological and Environmental Baseline Assessments:** This will comprise of a regional synthesis of available data in the three selected basins, consisting of:
  - a geological basin assessment to define stratigraphic and structural characteristics that could influence prospectivity, gas extraction and potential environmental risks;
  - data review and synthesis encompassing water quantity and quality, and;
  - a gap analysis to guide further data acquisition such as baseline water monitoring if required.
- **Stage 3 Impact Analysis and Management:** Bioregional assessments will consist of fit-for-purpose analysis to understand the potential impacts of future resource development scenarios on water and the environment. A range of plausible development scenarios will be developed in consultation with industry and the relevant state and territory governments and Commonwealth agencies, to test the range of potential impacts and enable consideration of suitable management measures.

Geoscience Australia (GA) and CSIRO are conducting the assessments. The program is managed by the Department of the Environment and Energy (DoEE) and supported by the Bureau of Meteorology (BoM).

This report contains the results of Stage 1 of the program, the rapid regional basin prioritisation, conducted by GA. It presents the context of the program and describes the evidence based decision making process used to narrow the focus of the Geological and Bioregional Assessments Program to areas of highest priority for further research in Stages 2 and 3.

2 Objective

The objective of Stage 1 of the Geological and Bioregional Assessments Program was to develop and implement a prioritisation process for the DoEE to use in advising the Australian Government on priority areas in which to undertake geological and bioregional resource assessments into the potential impacts on water and the environment from tight and shale gas development.

Large volumes of shale and tight gas resources (about 13 Tcf [13,961 PJ] of contingent [2C] resources as of December 2016) have been identified across various sedimentary basins across Australia (AERA, 2018). However, there remains uncertainty over the current viability of some of these resources, and further, extensive investment is required of currently undeveloped gas reserves and resources, to ensure demand on the East Coast Gas Market are met.

The Geological and Bioregional Assessments Program aims to encourage further shale and tight gas exploration activity through provision of pre-competitive geological and prospectivity data and information relevant to the shale and tight gas prospectivity of three priority sedimentary basins. The rapid regional basin prioritisation focused on selection of basins with the greatest potential to bring new shale and tight gas resources to the East Coast Gas Market within the next five to ten years. Such basins must have moderate to high prospectivity for shale/tight gas resources, moderate to high confidence in data quality and quantity (also reflected in exploration status), and be located close to the East Coast Gas Market or linked to it via appropriate infrastructure (including gas pipelines). Furthermore there needs to be no or only limited regulatory constraints preventing or impeding onshore gas exploration and development in the selected basins.

The Geological and Bioregional Assessments Program also presents a range of groundwater, surface water, environmental and social considerations relevant to each basin. These factors may potentially influence the ability to develop shale and tight gas projects within each basin and should be considered when prioritising and investigating basins.

The potential impacts of shale and tight gas extraction have been documented in various publications (see Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018; Victorian Legislative Council Environment and Planning Committee, 2015; and Cook et al., 2013; and references therein). Independent scientific assessments during the exploration phase for shale and tight gas resources will help to build community understanding of the industry and provide regulators and industry with a common information base to inform decision-making.

The scope of Stage 1 was limited to work that could realistically be completed and reported to the DoEE within the required three month time frame. Since timing precluded the gathering of new data or the extensive processing of existing datasets, the Stage 1 rapid regional prioritisation process was based on a set of key attributes for which data are already available. In addition, the process was designed to make the best use of existing broad-scale spatial data and the basin specific data were only included where no appropriate regional data were available.

3 Outline of rapid regional basin prioritisation methodology

The rapid regional basin prioritisation methodology was designed by GA in consultation with the DoEE to assist in identifying priority areas for further research. The methodology was modified from that developed by GA, the Commonwealth Scientific and Industrial Research Organisation (CSIRO), and the Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) for the Bioregional Assessment Program (GA, ABARES and CSIRO, 2012).

While the Bioregional Assessments were designed in order "to better understand the potential impacts of coal seam gas and large coal mining developments on water resources and water-dependent assets", this Geological and Bioregional Assessments Program focuses on shale and tight gas developments.

The general methodology used to identify priority areas is outlined in Table 3-1 and is described in more detail below.

Table 3-1 Geological and Bioregional Assessments Program Stage 1 rapid regional basin prioritisation process methodology

Step	Item	Description
1	Basin shortlist	Shortlist basins capable of supplying significant volumes of shale and/or tight gas to the East Coast Gas Market within the next 5 to 10 years.
2	Data inventory	Review of existing open file, national scale, petroleum and environmental data and information relevant to the basin audit of the shortlisted basins. In addition regional scale data is included, where relevant, to the audit shortlisted basins, as required.
3	Basin audit	Audit of shortlisted basins, using assessment matrix based on rapid prioritisation criteria.
4	Stakeholder engagement	Participation in interim stakeholder engagement (workshop or bilateral meetings) with relevant state/territory government agencies to facilitate the DoEE in its selection of the three priority basins.
5	Reporting	Final report preparations and delivery.

3.1 Basin shortlist

An initial shortlist of basins capable of supplying significant volumes of tight and/or shale gas to the East Coast Gas Market in the next five to ten years was identified through application of the following screening criteria to all Australian sedimentary basins:

- onshore sedimentary basin, in proximity to the East Coast Gas Market infrastructure;
- sufficient industry exploration activity for shale and/or tight gas plays, and;
- documented contingent (2C) and/or prospective shale and/or tight gas resources.

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 full review of current tight and shale gas exploration activity across eastern and northern Australia required the acquisition and assessment of the latest industry intelligence to update GA's internal database of tight and shale gas resource information. This included a review of contingent (2C) and prospective resources by basin and play type and an audit of key wells drilled targeting shale or tight gas plays. This information is not reported consistently even at a state level, so most information needed to be sourced from Australian Securities Exchange (ASX) media releases and industry websites on a company by company basis. Only information in the public domain was considered.

The details of the basin shortlisting process and associated results are described in Section 5.1 of this report and the full review of shale and tight gas resources and exploration activity for eastern and northern Australia can be found in Appendix A.

3.2 Data inventory

A review was conducted of pre-competitive petroleum and national scale, environmental and cultural data relevant to each shortlisted basin. In addition regional scale data were included, if national scale datasets were unavailable. This data inventory was conducted in two stages as follows.

- Review of datasets from the Bioregional Assessment Program to identify gaps for updating in the Geological and Bioregional Assessments Program.
- Inclusion of additional key geological and petroleum datasets into the extended BA data structure. Key additional datasets included those with the themes of geological provinces, petroleum wells, 2D seismic navigation data, 3D seismic data coverage, oil and gas fields, oil and gas pipelines, other relevant infrastructure (e.g. gas processing facilities).

Further details of the data inventory are described in Section 5.2 of this report and the national scale maps presenting environmental and social data are presented in Appendix B.

3.3 Audit of shortlisted basins

A rapid audit was then undertaken on the shortlisted 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;
- identify the water resources and environmental assets in each basin that could potentially be affected by shale and tight extraction.

Each basin audit was conducted based on the following rapid regional prioritisation criteria, and hence contains a brief summary of the following factors for each shortlisted basin.

- **Basin Geology:** including age, depth, lithology, depositional environment, source rock and reservoir formations, petroleum systems (e.g. known, hypothetical, speculative), summary of key unconventional play types (including formation, source rock characteristics).
- **Resources:** including 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 (by play type); approximate development timeframe.
- **Market access and infrastructure:** road and rail access; proximity of prospective area to existing gas infrastructure, including pipelines and thereby market access.
- **Regulatory:** hydraulic fracturing moratoria; exploration moratoria.
- **Environmental constraints:** including groundwater systems; surface water systems; environmentally sensitive areas, such as groundwater-dependent ecosystems, important wetlands and national parks.
- **Social factors/constraints:** population distribution; existing land use; culturally significant areas.

As the above information was sourced from a diverse range of public domain, government and industry sources, the basin audit process was designed to ensure the following.

- **Consistent and transparent reporting:** To ensure decision making is evidence-based, significant work was required to ensure consistent and transparent reporting across all of the prioritisation criteria. The project required integration of disparate information and spatial data from a range of sources on petroleum geology, unconventional gas resources, environmental conditions and potential stressors.
- **Effective synthesis across state and territory borders:** Where basins cross state/territory borders (e.g. Cooper, Georgina, McArthur and Otway basins and Isa Superbasin), additional work was required to synthesise and standardise the relevant information to give a whole of basin perspective.
- **A fit for purpose product:** Recasting was required to ensure the information in this report is fit for purpose.
- **Capture of uncertainty in knowledge:** The type, coverage, quantity and quality of data vary significantly between basins, resulting in differences in confidence in geological knowledge. Reviewing existing data in a consistent format provides an initial framework for future gap analyses, highlighted areas and themes where acquisition of new pre-competitive information would have the greatest impact.

The results of each prioritisation criteria are presented in tables, maps and matrices in Section 5.3 of this report, and within the basin summary documents in Appendix C.

3.4 Stakeholder engagement

Throughout Stage 1 of this project, GA engaged with the DoEE to discuss and agree on the scope the project. This process included the following steps:

- an initial workshop on 30th June 2017 to discuss possible selection criteria and prioritisation process;
- follow up conversations to refine and finalise the rapid regional prioritisation process and criteria, and;
- finalisation of the Stage 1 project agreement between GA and the DoEE.

The DoEE has actively engaged with relevant industry and state and territory government stakeholders to facilitate the scoping of the Geological and Bioregional Assessments Program. To support the DoEE and participating stakeholders with the decision making process, results of Stage 1 have underpinned a) preliminary documentation explaining the screening process and basin audit and b) advice from GA on both the tight and shale gas prospectivity of Australian basins, along with the potential impacts of development of these resources on water resources.

3.5 Reporting

This report contains the results of Stage 1 of the Geological and Bioregional Assessments Program, the rapid regional prioritisation, conducted by GA. It presents the context of the program and describes the evidence based decision making process used to narrow the focus of the geological and bioregional resource assessments to areas of highest priority, based on the prioritisation framework outlined above. This compilation and assessment provides scientific information to inform decisions by the DoEE and stakeholders on the three basins that will proceed to Stages 2 and 3 of the Geological and Bioregional Assessments Program.

4 Gas resources

4.1 Conventional and unconventional gas resources

4.1.1 The Petroleum System

The term ‘petroleum system’ describes the genetic relationship between an active source rock and the resulting oil and gas accumulations (Magoon and Dow, 1994). It includes all the essential elements and processes needed for oil and gas accumulations to exist. These include the source, reservoir, seal, and overburden rocks, the trap formation, and the hydrocarbon generation, migration and accumulation processes. All essential elements and processes must occur in the appropriate time and space in order for petroleum to accumulate (Magoon and Dow, 1994).

Organic material, incorporated during the deposition of sedimentary material, is heated during burial, converting the organic material to hydrocarbons in a process called maturation. A portion of the petroleum formed may be expelled from the source rock, and may then migrate through permeable sediments and structures until it is trapped by an impermeable barrier forming a conventional accumulation, or it escapes to the Earth’s surface. Alternatively, in circumstances where porosity and permeability are limited, some or all of the petroleum may stay trapped in or quite near the source rock, these are known as unconventional accumulations.

4.1.2 Conventional petroleum accumulations

‘Conventional’ petroleum accumulations are so called because they have the longest association with petroleum exploration and production, and are considered the norm i.e. ‘conventional’ by the industry. These accumulations were the first to be exploited by shallow drilling and have provided the majority of oil and gas produced worldwide to date. However, they are relatively rare, comprising a small part of the petroleum continuum.

‘Conventional’ petroleum accumulations occur as discrete accumulations (Figure 4-1) trapped by a geological structure and/or stratigraphic feature, typically bounded by a down-dip contact with water (Figure 4-1) (Schmoker, 1995, 2002). The petroleum was not formed in situ; it migrated from the source rocks into a trap containing porous and permeable reservoir rocks. The petroleum is extracted through relatively few wells, usually with no permeability enhancement needed.

4.1.3 Unconventional accumulations

The term ‘unconventional’ is used to refer to the collection of petroleum accumulations, that include shale oil and gas, oil shales, tight sands, basin-centred gas, coal seam gas, deep coal gas and methane hydrates. ‘Unconventional' and 'conventional' petroleum accumulations can form from the same source rocks (Figure 4-1; Schmoker, 1995, 2002). However, differences in expulsion, transport, and trap mechanisms result in different extraction methods being needed for ‘conventional’ and ‘unconventional’ resources.

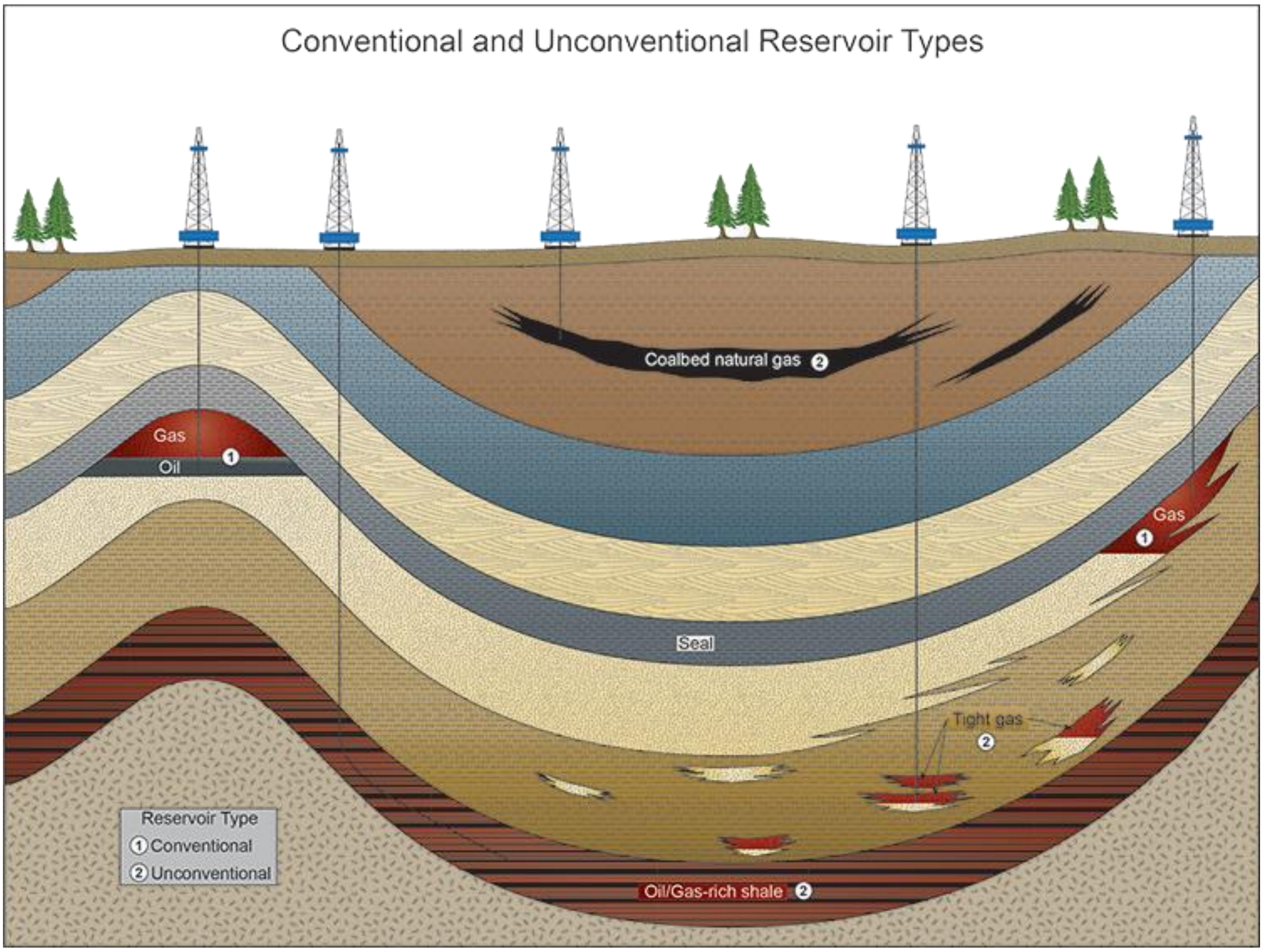


Figure 4-1: Schematic showing some of the types of oil and gas accumulations (after Wyoming State Geological Survey, 2018).

An unconventional accumulation is a single large field (commonly of regional dimensions) that is not composed of discrete, countable fields delineated by downdip water contacts. These accumulations are not significantly influenced by the water column and do not owe their existence directly to the buoyancy of gas in water. The 'fields' that are sometimes named within an accumulation are actually indistinctly bounded areas with better production characteristics (sweet spots) (Schmoker, 2002).

The United States Geological Survey (USGS) has introduced the term 'continuous accumulation' to geologically differentiate between 'conventional' and 'unconventional' petroleum systems (Schmoker, 1995). In Australia the term 'unconventional' is more typically used.

In Australia, the types of unconventional gas accumulations include basin-centred gas, tight gas, shale gas and coal seam gas (AERA, 2018). These are described in more detail below.

4.1.3.1 Tight gas and basin centred gas accumulations

Tight gas reservoirs have been exploited for several decades, including in Australia, and are well understood (Cook et al., 2013). These include discrete tight gas reservoirs where migrated gas accumulates in rocks with low porosity and permeability, in a similar manner to conventional accumulations and more distributed basin centred gas accumulations.

Basin centred gas accumulations are low permeability, gas reservoirs which are commonly abnormally overpressured and lacking a down dip water contact. The hydrocarbons have migrated from a source rock, and the gas is trapped as a 'bubble' within a high pressure, water saturated reservoir. This phenomenon is caused by the relative permeability of gas and water in the reservoir. The combined effect of high water pressure and capillary pressure resulting from narrow pore size in the tight reservoirs prevents hydrocarbons from migrating freely and so they remain trapped. These reservoirs can be laterally and vertically extensive, with gas saturation pervasive throughout. The rate of migration of gas into the reservoir exceeds the rate of gas migrating out of the reservoir, which implies that these reservoirs exist only contemporaneously with active gas generation from a nearby source.

Tight gas plays typically occur between 1,500 m and 4,000 m depth. Pore sizes and pore-throat sizes (diameters), which impact on the reservoir permeability, range from about 2 to 0.03 µm in tight-gas reservoirs (Nelson, 2009). This is in contrast to conventional reservoir rocks where they are generally greater than 2 µm.

4.1.3.2 Shale gas

Shales are a common petroleum source rock, and can retain more petroleum than they expel during maturation. They have low to moderate porosity with pore sizes on the nanometre scale (ranging from 0.1 to 0.005 µm; Nelson, 2009), and have very low permeability. They are sometimes referred to as 'self-sourcing reservoirs'. They occur with significant (10–100 km) lateral continuity and can be of considerable thickness (0.1–100 m) Shale gas plays usually occur at similar depths to tight gas plays.

4.1.3.3 Coal seam gas

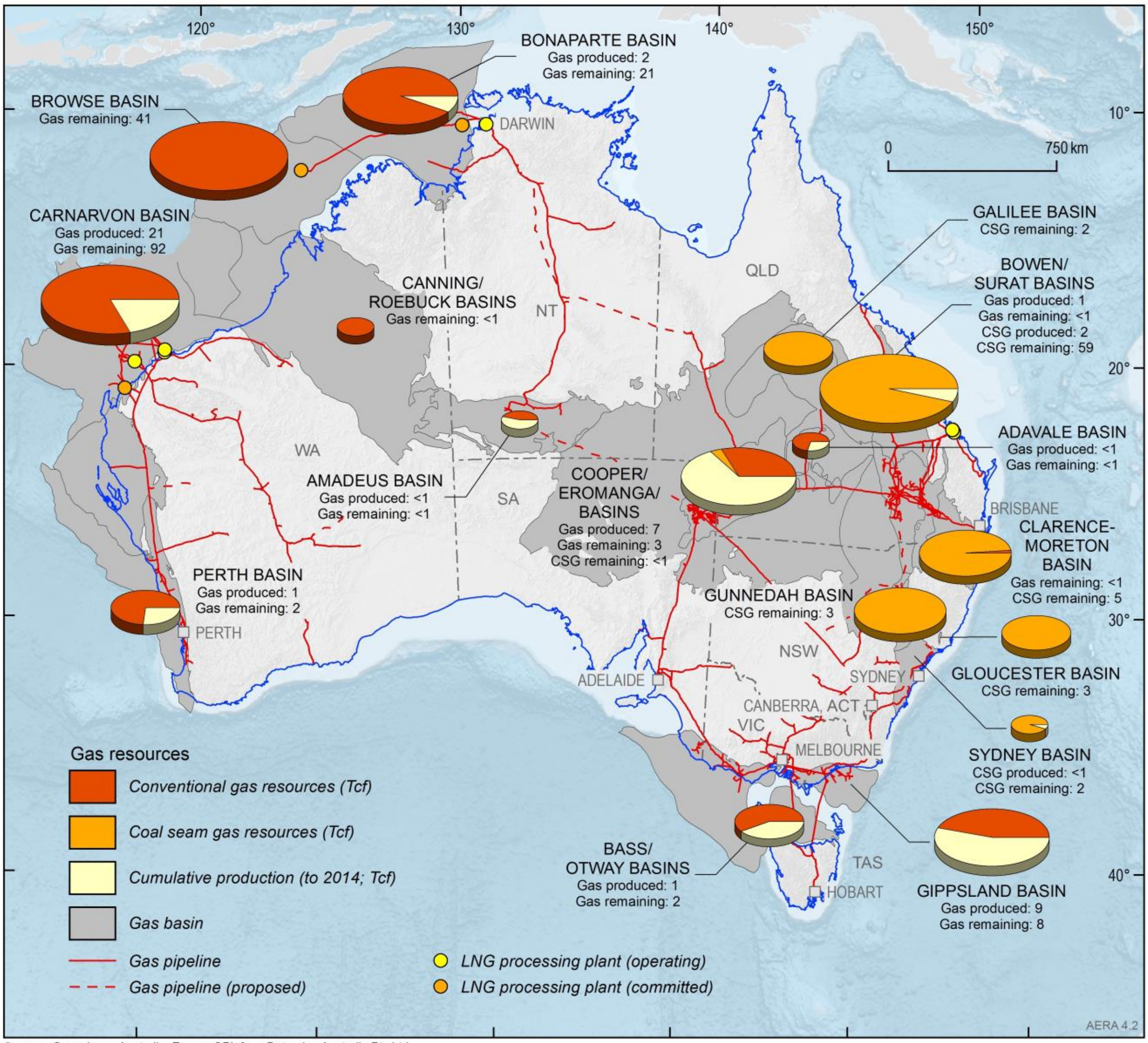
Coals release methane through either thermal or biogenic maturation. As organic material is converted to gas there is a significant increase in volume that fractures the coal. The gas is transiently held in place either in the fractures or adsorbed onto the coals surface by hydrostatic pressure. The large surface area to volume ratio of coals makes them very high capacity reservoirs. In contrast to both shale and tight gas plays, coal seam gas plays are typically found at depths of less than 1,000 m. Gas extracted from coals at depths usually below 2,000 m are often described as 'deep coal gas'. Due to cleat closure and the loss of fracture permeability with depth, fracture simulation is used to release the free gas held within the organic porosity and fracture system within the coal seam. As dewatering is not needed, this makes them similar to shale gas reservoirs (Goldstein et al, 2012; Camac et al., 2018).

4.2 Australia's shale and tight gas resources

Australia has substantial conventional and unconventional gas resources, the latter including coal seam gas (CSG), shale gas and tight gas (Figure 4-2). Total identified gas resources are of the order of 257 Tcf (279,819 PJ), which includes a total of approximately 13 Tcf (13,961 PJ) of contingent (2C) shale and tight gas resources (AERA, 2018).

The lack of current reported shale and tight gas reserves for Australia reflects the very early stage of exploration, a lack of infrastructure in the exploration areas and low oil and gas prices (AERA, 2018). Although Santos reported first shale gas production and 2.8 bcf (3 PJ) reserves from the

Moomba gas field in the Cooper Basin in 2012 (Santos, 2012), these were subsequently downgraded to contingent resources.



Source: Geoscience Australia, Encom GPinfo, a Datamine Australia Pty Ltd.
Whilst all care is taken in the compilation of the petroleum pipelines by Datamine, no warranty is provided re the accuracy or completeness of the information, and 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 reliance is placed on them. Accurate at August 2017.

Figure 4-2

As of December 2016, early exploration had identified a total of 11 Tcf (12,252 PJ) of contingent (2C) shale gas resources across Australia. About 80% of these were reported in the Cooper Basin, with additional resources identified in the Isa Superbasin and Perth Basin (AERA, 2018). In 2017, Origin Energy reported a further 6.6 Tcf (approximately 7,260 PJ) of contingent shale gas resources within the Beetaloo Sub-basin of the McArthur Basin (Origin Energy, 2017). In addition, approximately 2 Tcf (1,709 PJ) of tight gas contingent resources have been identified (AERA, 2018). The known tight gas resources are located in the established conventional gas-producing basins – the Cooper, Perth and Gippsland basins. These resources are located relatively close to infrastructure and are currently being considered for commercial production.

Australia has estimated prospective shale and tight gas-in-place resources of 8,490 Tcf (9,338,993 PJ) and 2,410 Tcf (2,622,022 PJ) respectively (AERA, 2018). Likely shale gas candidate formations have been identified in many basins, including the Amadeus, Bowen, Canning, Clarence-Moreton, Cooper, Eromanga, Georgina, Maryborough, McArthur, Otway basins, Pedirka and Perth basins, along with the Isa Superbasin. In addition, prospective resources of tight gas have been assessed from low-permeability sandstone reservoirs in the Amadeus, Bowen, Canning, Cooper, Gippsland, Otway and Perth basins. It should be noted that prospective resources are poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty. However, if these shale and tight gas resources can be effectively developed, they have the potential to provide a significant source of gas supply to the East Coast Gas Market in the future.

Definitions of ‘reserves’, ‘contingent resources’ and ‘prospective resources’, along with a full definition of the resource classification scheme (PRMS, 2007) can be found in Appendix A.

4.3 Australian gas markets

The following section provides an overview of Australia’s gas industry and regional gas markets, as context for the rapid regional prioritisation process. This content has been summarised from the Australian Energy Regulator’s report “State of the Energy Market May 2017” (AER, 2017) and the Australian Energy Resource Assessment 2014 (GA and BREE, 2014).

4.3.1 Gas supply chain

Figure 4-3 illustrates the simplified operation of the gas industry in Australia. Resources are delivered to domestic and export markets through the successive activities of exploration, development, production, processing and transport. While different technologies can be used for extracting CSG and other unconventional gas, once extracted it is indistinguishable from conventional natural gas and the supply chain is the same.

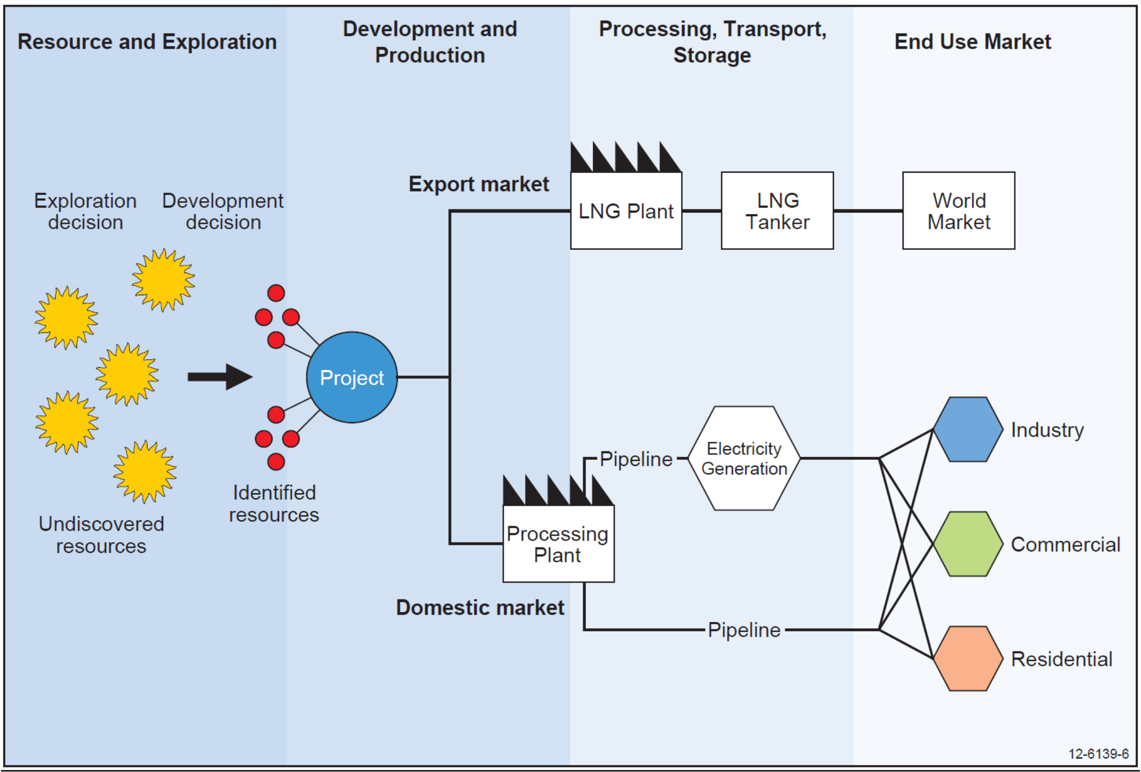


Figure 4-3 Australia's gas supply chain (GA and BREE, 2014).

Key stages in the gas supply chain are described below.

- **Exploration:** The gas supply chain begins with exploration and appraisal of potential reserves for commercial viability. Geoscientists identify areas where hydrocarbons are liable to be trapped in the subsurface, first by using broad regional geological studies to identify potential play types, then as more data are collected, individual drilling targets are identified. For drilling to be undertaken, there must be evidence of a working petroleum system, including the presence of other petroleum discoveries in the case of a proven basin, or indications of the presence of organic-rich rock to act as a gas source in the case of frontier basins. Drilling is required to test whether the targeted area contains oil or gas, both, or neither. Successful wells are commonly tested to recover a sample of the hydrocarbons for analysis to determine gas quality (liquids content and presence of CO_2) and to determine likely production rates.
- **Appraisal:** In the evaluation or appraisal phase, additional information is collected about the identified accumulation, to determine commercial viability and potential reserves. Appraisal drilling and/or the collection of further seismic survey data is commonly required to help determine the extent of the accumulation.
- **Development:** Once a decision to proceed has been made and financial and regulatory requirements addressed, infrastructure and production facilities are developed. Development stages include concept/ feasibility study, FEED (Front End Engineering Design) and development, FID (Final Investment Decision).
- **Production:** Once development is complete, hydrocarbons are extracted at commercially viable quantities, typically from more than one well. In the case of tight and shale gas formations, horizontal drilling may be used and hydraulic fracturing may be undertaken to achieve commercial flow rates.

- **Processing:** The gas extracted from the well requires processing to separate the sales gas from other liquids and gases that may be present, and to remove water, CO_2 and other impurities before it can be transported efficiently by pipeline or ship. As a result, processing tends to occur near the production well. In some fields, gas production is associated with other petroleum products such as crude oil, condensate (light oils) and gas liquids (ethane, propane, butane, isobutane, and pentane).
- **Transport and storage:** Apart from small quantities used on site for electricity generation or other purposes, gas usually requires transport for long distances to major markets. This is managed in Australia by gas pipelines (for domestic use), and in liquefied form (LNG) by tanker (for export) Natural gas not used immediately can be placed in storage until it is needed.

4.3.2 Regional gas markets

The Australian domestic gas market consists of three distinct regional markets (Figure 4-4; AER, 2017).

- The **East Coast Gas Market** includes Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT, and is interconnected by a network of transmission pipelines. The East Coast Gas Market mostly sources gas from the Surat–Bowen and Cooper basins onshore and the offshore Gippsland and Otway basins and is the only market where coal seam gas supplements conventional gas supplies (AER, 2017).
- The **Northern Territory Gas Market** is located in the Northern Territory and is supplied by the Amadeus and Bonaparte basins. It is the smallest producer and consumer of gas in Australia (AER, 2017).
- The **West Coast Gas Market** is located within Western Australia and is supplied by the Carnarvon and Perth basins (AER, 2017).

Each market comprises a network of transmission pipelines which transport gas at high pressure from producing fields to major demand centres (hubs; Figure 4-4). In Australia, pipeline infrastructure is privately owned and 80% of transmission pipelines are unregulated and can set their own terms and conditions (AER, 2017). A full list of the East Coast and Northern Territory gas market pipeline and gas storage facilities are summarised in Table 4-1.

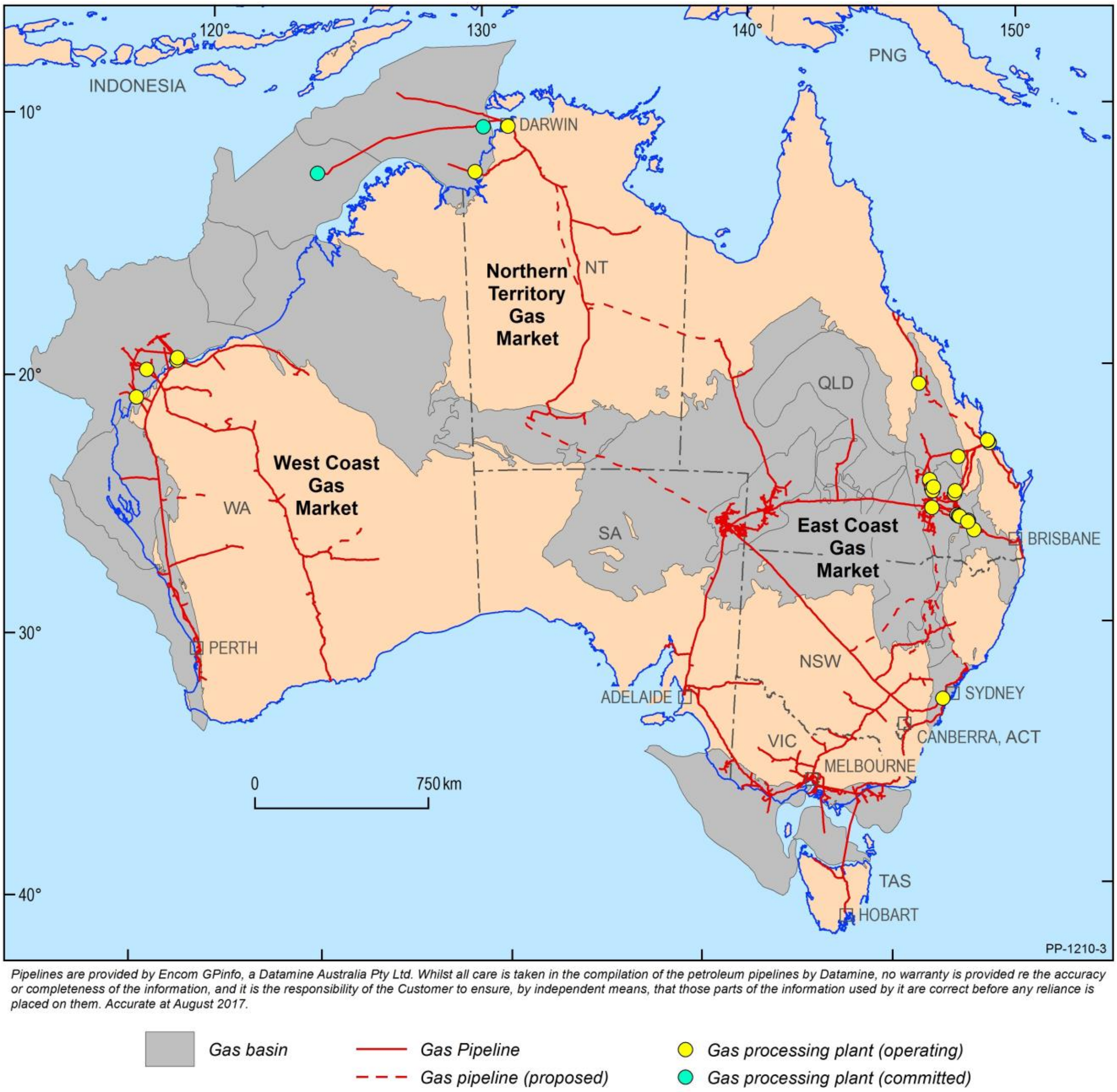


Figure 4-4 Australia's gas pipelines (GA, 2015a) and processing facilities (GA, 2015b).

Table 4-1 Major gas transmission pipelines in eastern and northern Australia (AER, 2017)

Pipeline	Length (km)	Capacity (TJ/day)	Owner
QUEENSLAND			
Roma (Wallumbilla) to Brisbane	438	233 (125 reverse)	APA Group
South West Queensland Pipeline	756	404 (340 reverse)	APA Group
QSN Link	182	404 (340 reverse)	
Queensland Gas Pipeline (Wallumbilla to Gladstone)	627	149 (40 reverse)	Jemena
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	APA Group
GLNG Pipeline	435	1,430	Santos 30%, Petronas 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	334	1,588	APA Group

Pipeline	Length (km)	Capacity (TJ/day)	Owner
APLNG Pipeline	530	1,560	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Berwyndale to Wallumbilla Pipeline	112	164 (276 reverse)	APA Group
Dawson Valley Pipeline	47	30	Westside 51%, Mitsui 49%
Wallumbilla to Darling Downs Pipeline	205	270 (530 reverse)	Origin Energy
Comet Ridge to Wallumbilla Pipeline	127	950 (175 reverse)	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
North Queensland Gas Pipeline	391	108	Victorian Funds Management Corporation
NEW SOUTH WALES			
Moomba to Sydney Pipeline	2,029	439 (381 reverse)	APA Group
Central West Pipeline (Marsden to Dubbo)	255	10	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	294	7	APA Group
Eastern Gas Pipeline (Longford to Sydney)	797	351	Jemena
VICTORIA			
Victorian Transmission System (GasNet)	2,035	1,030	APA Group
South Gippsland Pipeline	250		DUET Group
Vic–NSW Interconnect		153 (196 reverse)	Jemena
SOUTH AUSTRALIA			
Moomba to Adelaide Pipeline	1,184	241 (55 reverse)	QIC Global Infrastructure
SEA Gas Pipeline (Port Campbell to Adelaide)	580	314	APA Group 50%, Retail Employees Superannuation Trust 50%
TASMANIA			
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	Palisade Investment Partners
NORTHERN TERRITORY			
Bonaparte Pipeline	286	80	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)
Amadeus Gas Pipeline (Amadeus Basin to Darwin)	1,658	120	APA Group
Daly Waters to McArthur River Pipeline	332	16	Power and Water
Palm Valley to Alice Springs Pipeline	146	27	Australian Gas Networks (Cheung Kong Infrastructure)

At present, Australia's three gas markets are geographically isolated from one another. As a result, all gas production is either consumed within each market or exported as LNG. However the planned Northern Gas Pipeline (NGP), to run between Tennant Creek and Mount Isa, is expected to start operating in 2018 and will connect the East Coast and Northern Territory gas markets (Jemena, 2017). The NGP will enable the Northern Territory to potentially provide a major new source of gas to meet east coast demand in the long term. While the present volumes are relatively modest in the context of the overall East Coast Gas Market, they would still add important incremental volumes to domestic supply in Queensland (ACCC, 2016).

4.4 Shale and tight gas exploration, development and management

Shale gas and coal seam gas is natural gas that is still within the source rock, not having migrated to a porous and permeable reservoir. Tight gas accumulations occur within poor quality reservoirs i.e. have low porosity and permeability.

As a result of these differences, exploration for unconventional gas differs somewhat from the search for conventional hydrocarbons, especially when the target is a broadly distributed stratigraphic formation such as a coal bed or shale. Seismic surveys and drilling still constitute the major exploration technologies. However, the distribution of the prospective formation is usually well known at the regional scale, and exploration success depends on identifying parts of the formation where the gas resource and reservoir quality are sufficient to sustain a flow of gas on a commercial scale i.e. sweet spots.

The petroleum resource pyramid (McCabe, 1998) compares how a smaller volume of easy to extract conventional gas is generally associated with larger volumes of more difficult and more costly to extract unconventional gas (Figure 4-5; GA and BREE, 2014). For unconventional hydrocarbon resources, additional technology, energy and capital has to be applied to extract the gas.

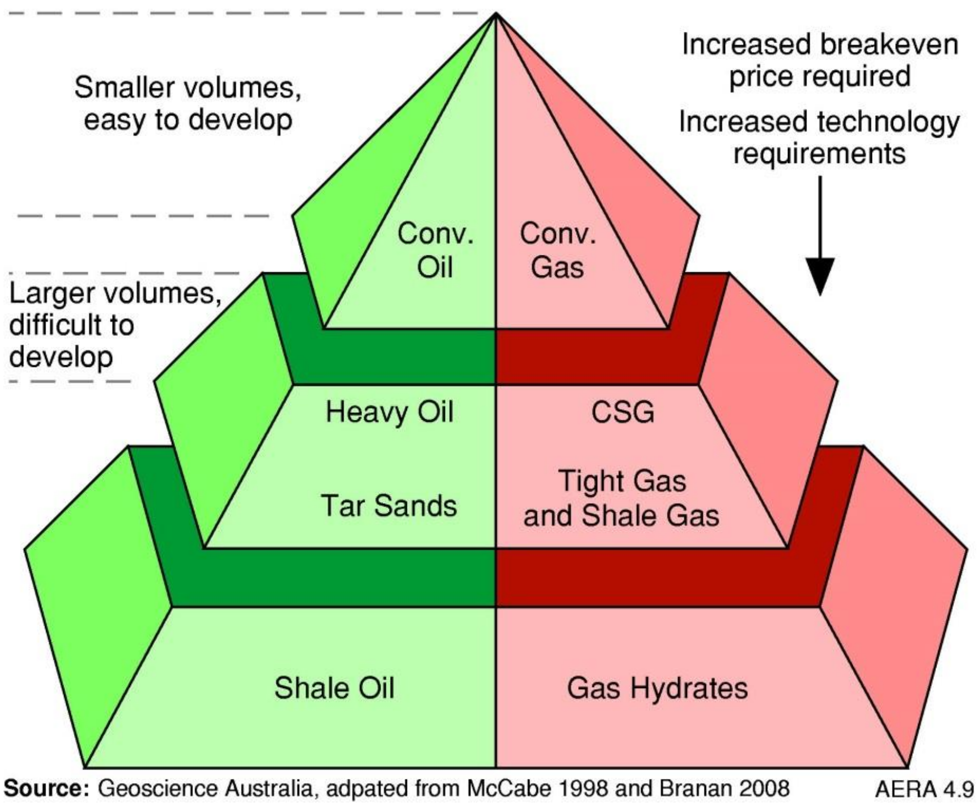


Figure 4-5 Resource pyramid (GA and BREE, 2014).

4.4.1 Extraction technologies

In conventional gas accumulations, the hydrocarbons are located in discrete traps defined by dry holes, with high porosity and permeability. As a result they can typically be developed with a limited number of wells, in which gas flows to the surface under its own pressure. Unconventional gas plays are generally more distributed and have much lower porosity and permeability, restricting movement of gas through the rock. As a result, in order to extract the gas from unconventional plays, artificial stimulation may be required to increase the level of porosity and permeability, which generally involves hydraulic fracturing. In addition, horizontal drilling techniques have improved commercial extraction, particularly for shale gas plays.

A brief discussion on hydraulic fracturing and unconventional gas extraction techniques is summarised below from the following key sources: CSIRO (2017), Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018), Victorian Legislative Council Environment and Planning Committee (2015), Cook et al. (2013) and South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy (2012).

4.4.1.1 Hydraulic fracturing

Hydraulic fracturing, commonly referred to as fracking or fraccing, has been used by the oil and gas industry since the late 1940s to increase the rate and total amount of oil and gas extracted from reservoirs (CSIRO, 2017).

Hydraulic fracturing is a process of inducing fine fractures into the low-permeability rock to allow unconventional hydrocarbons, including shale gas or tight gas, to be extracted from the reservoir. The hydraulic fracturing process requires a well with cemented steel casing that is perforated at the chosen depth in the target reservoir. Hydraulic fracturing fluid, which is water supplemented with proppant and other additives, is pumped down to this target at high pressure, to create or enlarge the fractures and to ‘prop’ them open (CSIRO, 2017). Gas and ‘flowback’ then return up the well, and are separated at the surface (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018; Victorian Legislative Council: Environment and Planning Committee, 2015; Cook et al., 2013; South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy, 2012). Large amounts of water are required for hydraulic fracturing fluids, however only a portion of the water that is used in the hydraulic fracturing process is returned to the surface.

4.4.1.2 Unconventional gas extraction techniques

Horizontal drilling techniques have improved commercial extraction of unconventional hydrocarbons. Horizontal wells targeting shale gas are often 600 m to 3 km in lateral extent, with the well curving from vertical to horizontal to intersect the target formation (Cook et al., 2013). Typically a multi-stage approach is used to fracture a well, with between 10 and 40 stages along a single lateral well. Each stage is isolated and fracked, after which the process moves to the next stage. Horizontal drilling allows multiple wells to be drilled from a single well pad. It is expected that well pads will be in the order of one pad per 10–20 km^2 in Australia, based on current proposals (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018; Victorian Legislative Council Environment and Planning Committee, 2015; Cook et al., 2013; South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy, 2012).

There are significant differences in the extraction techniques for the different forms of unconventional gas (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018)—

- **Coal seam gas:** The extraction of coal seam gas does not always require hydraulic fracturing, but does require the removal of water from the coal, depressurising the seam to release the adsorbed gas, so it, together with the free gas can flow to the surface. Large amounts of brine are commonly produced as a result of this process, which must be treated and disposed.
- **Tight gas:** Porosity and permeabilities are so low that hydraulic fracturing is always necessary to allow the trapped gas to be produced at economic rates, but unlike coal seam gas, it does not need to remove large quantities of existing groundwater for gas to be produced. Vertical wells are most common for tight gas extraction.
- **Shale gas:** As for tight gas, the extraction of gas from shale requires hydraulic fracturing, but does not require the removal of large quantities of existing groundwater. Shale gas extraction is most commonly associated with horizontal drilling.

Unconventional hydrocarbon extraction requires a much greater density of wells than conventional extraction, as the sweep area of an unconventional well is much less than that of a well producing from a high permeability reservoir.

4.4.2 Stages of shale and tight gas exploration and development

The stages of shale and tight gas exploration and development, modified from the Northern Territory Government Scientific Inquiry into Hydraulic Fracturing (Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018), are listed below.

- **Stage 1:** identification of the gas resource – negotiation and securing land access agreements, securing seismic survey and drilling permits and undertaking initial geological, geophysical and geochemical surveys.
- **Stage 2:** early evaluation drilling – seismic mapping of the extent of gas-bearing formations and other geological features such as faults, initial vertical drilling to evaluate shale or tight gas resource properties and collection of core samples.
- **Stage 3:** pilot project drilling – drilling of initial wells to determine reservoir properties and to help optimise operational techniques and initial production testing.
- **Stage 4:** pilot production testing drilling – drilling of multiple horizontal wells from a single pad for shale gas targets or, more commonly, vertical wells for tight gas targets, full optimisation of operation techniques including drilling and multi-stage hydraulic fracturing, pilot production testing, and planning of pipeline corridors for field development.
- **Stage 5:** commercial development – following a commercial decision to proceed (FID), and government approvals for construction of gas plants, pipelines and other infrastructure, the drilling and fracturing of a network of production wells.
- **Final stage:** decommissioning – removal of the wellhead, plugging the well casing with cement and steel, and removal of all production equipment, production waste, pipelines and other infrastructure, and the rehabilitation of all cleared areas.

In general tight gas development follows a slightly less complex pathway to shale gas development, as vertical wells are used for pilot project evaluation and production testing.

5 Rapid regional basin prioritisation

5.1 Shortlist of basins with shale and/or tight gas prospectivity

Basins capable of supplying significant volumes of shale and/or tight gas to Australia's East Coast Gas Market in the next five to ten years were identified by considering: a) basin location and b) the level of industry exploration activity for shale and/or tight gas plays. Basins where shale and/or tight gas exploitation is currently occurring, or is likely to occur in the near future, or where shale and tight gas exploration is ongoing, were shortlisted as priority areas for early research.

5.1.1 Eastern and northern Australian sedimentary basins

The locations of Australian sedimentary basins were sourced from the Australian Geological Provinces database (Stewart et al., 2013). Out of approximately 120 onshore sedimentary basins; approximately 60 are located within 400 km of either existing East Coast or Northern Territory Gas Market infrastructure or infrastructure under construction (Figure 5-1).

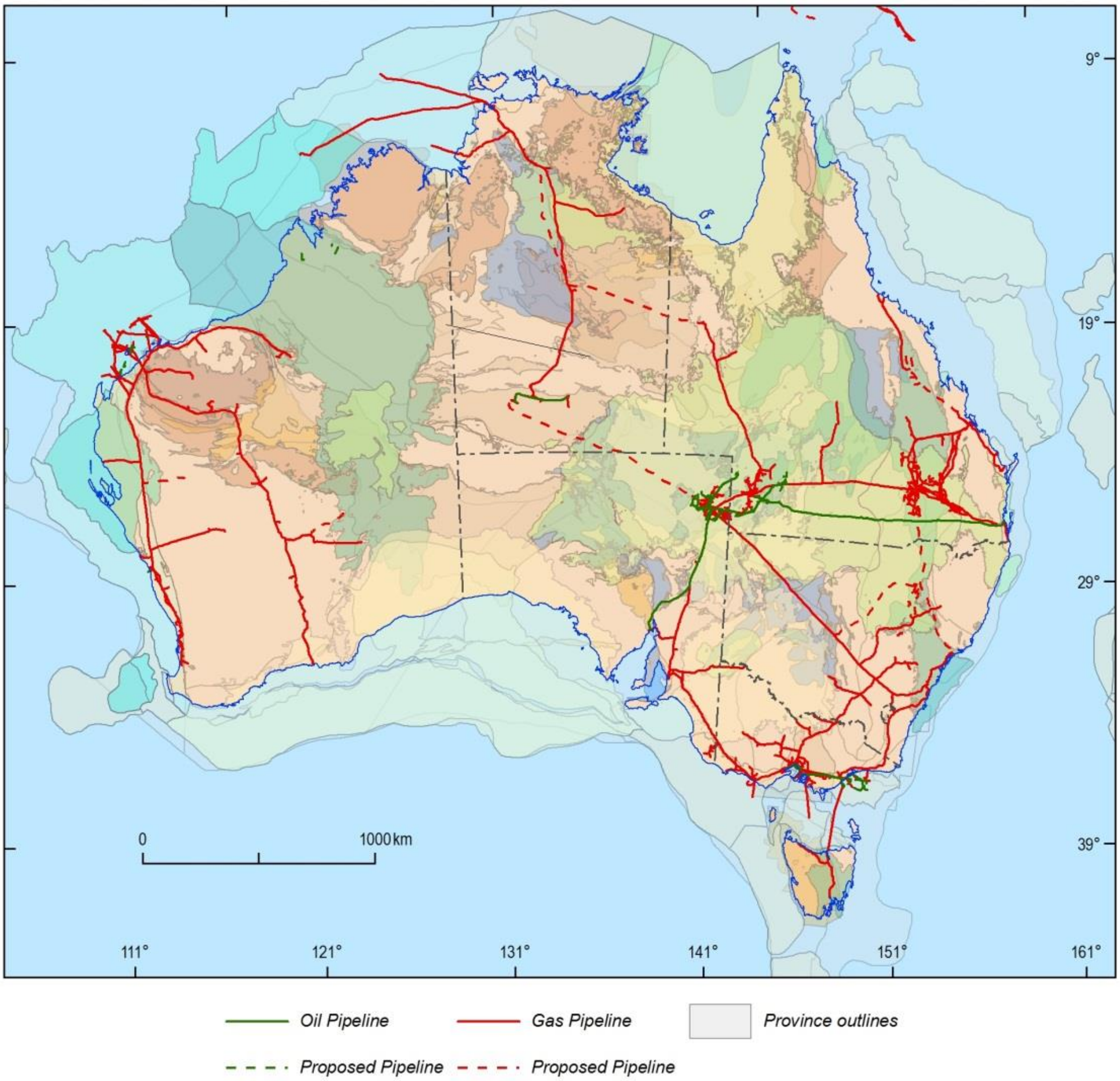


Figure 5-1 Australian sedimentary basins and gas market location. Province outlines from Stewart et al. (2013). Oil and gas pipelines from GA (2015a).

5.1.2 Approximate development timeframe

A review and summary of the exploration status for eastern and northern Australian Basins was undertaken for this study, including an update of reported shale and tight gas contingent and prospective resources. A comprehensive review of the exploration status of all potential shale and tight gas plays is also included. The data underpinning this review is all public domain and key sources include: federal, state and territory government reports and websites, third party reviews and industry intelligence sourced from company websites, ASX media releases and other news articles. The full results of the review, with associated references, are found in Appendix A.

In addition and where possible, wells targeting shale or tight gas plays were identified from a variety of sources including state government reports and industry media releases (e.g. Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, 2018; DNRM, 2017; see Appendix A for full reference list). However it should be noted that this list is not comprehensive and there are inconsistencies between well classifications depending on the data source.

This review identified a total of 27 eastern and northern Australian basins that contain possible tight and/or shale gas plays, as listed in Table A.2, in Appendix A.

An approximate future development timeframe can be estimated based on the stage of existing exploration and development in the basin (Figure 5-2; Table 5-1), assuming sustained investment and no other impediment to development (e.g. regulatory restrictions and environmental or social concerns). For gas to be brought to the East Coast Gas Market within a five to ten year time frame, active exploration for shale and or tight gas resources must already be underway in the basin, with possible plays, leads or prospects already identified.

Table 5-1 Approximate timeframe for delivery to market by stage of development. This assumes sustained funding of activities and no other impediment to development (e.g. regulatory restrictions; environmental or social concerns).

Phase of development	Metric	Time frame for gas delivery to market
No exploration activity	no well drilled	>10 years
Preliminary exploration	investigation at play level; initial drilling but no discovery	8 to >10 years
Exploration	investigation at play prospect level; discovery well	5–10 years
Early appraisal	discovery but not mature; contingent resources	5–10 years
Appraisal	discovery mature for development decision; contingent resources/ reserves	5–8 years
Development	committed for or under development; reserves booked	≤5 years

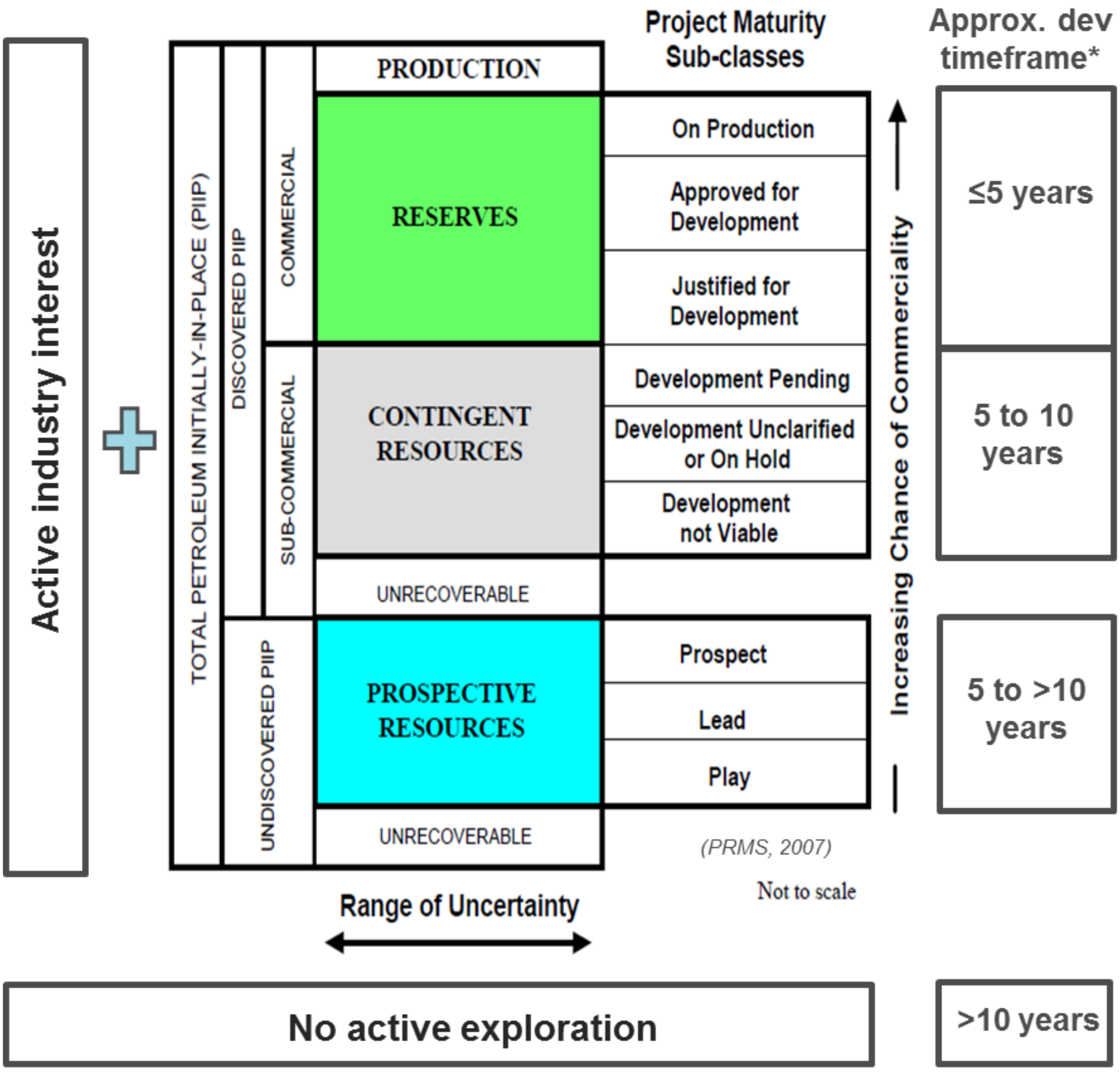


Figure 5-2 Modified PRMS scheme (PRMS, 2007), with approximate development timeframes, assuming sustained funding of activities and no other impediment to development (e.g. regulatory restrictions; environmental or social concerns).

The exploration status of basins with identified shale and/ or tight gas plays is summarised in Table 5-2 and Figure 5-3. Key results are as follows:

- The Cooper Basin is at an advanced appraisal phase. If there were no other impediment to development in these areas, such as regulatory restrictions or environmental or social concerns, the likely development timeframe is estimated to be between five and eight years.
- The Gippsland and McArthur basin and Isa Superbasin are in the early appraisal phase, with a suggested development timeframe of five to ten years (again assuming no other impediment to development).
- Exploration is underway to varying extents in a further five basins (Amadeus, Bowen, Clarence-Moreton, Georgina and Otway basins), with expected development timeframes of eight to more than ten years.

- Development in the Pedirka, Gunnedah and Maryborough basins is likely to take much more than ten years. Although these basins contain potential plays shale and/or tight gas plays, there is no current activity or exploration is at such an early stage that it is difficult to assess its potential.
- The prospective recoverable resource estimate of 82 Tcf (approximately 90,000 PJ) for the Toolebuc Formation shale gas play in the Eromanga Basin by AWT International (2013) has not been included in this analysis, as this large resource size is inconsistent with poorer than expected exploration results (Exoma Energy, 2012; DNMR, 2017). Significant additional work would be required to prove the viability of this play (DNRM, 2017) and hence the development timeframe is estimated to be much greater than ten years.
- Contingent resources (2C) of 0.14 Tcf (157 PJ) have recently been estimated from sandstones in the Albany structure in the Galilee Basin (Comet Ridge, 2017). However based on the public information available, it is unclear what proportion of this (if any) represents tight gas, so this contingent resource estimate is excluded from the analysis at this point. In addition, these contingent resources have been estimated from existing exploration wells. Further drilling would be required to test this structure; therefore development timeframe is still estimated to be much greater than ten years.
- There is no current industry activity in all other basins containing shale and/or tight gas plays (see Appendix A for full basin list). In these basins any development is likely to take much more than 10 years.

Based on this analysis, nine onshore basins were identified in which active exploration for shale and or tight gas resources is already underway and possible plays, leads or prospects have already been identified. These basins were considered to have development timeframes of ten years or less assuming sustained investment and no other impediment to development and hence have been shortlisted as priority areas for further early research.

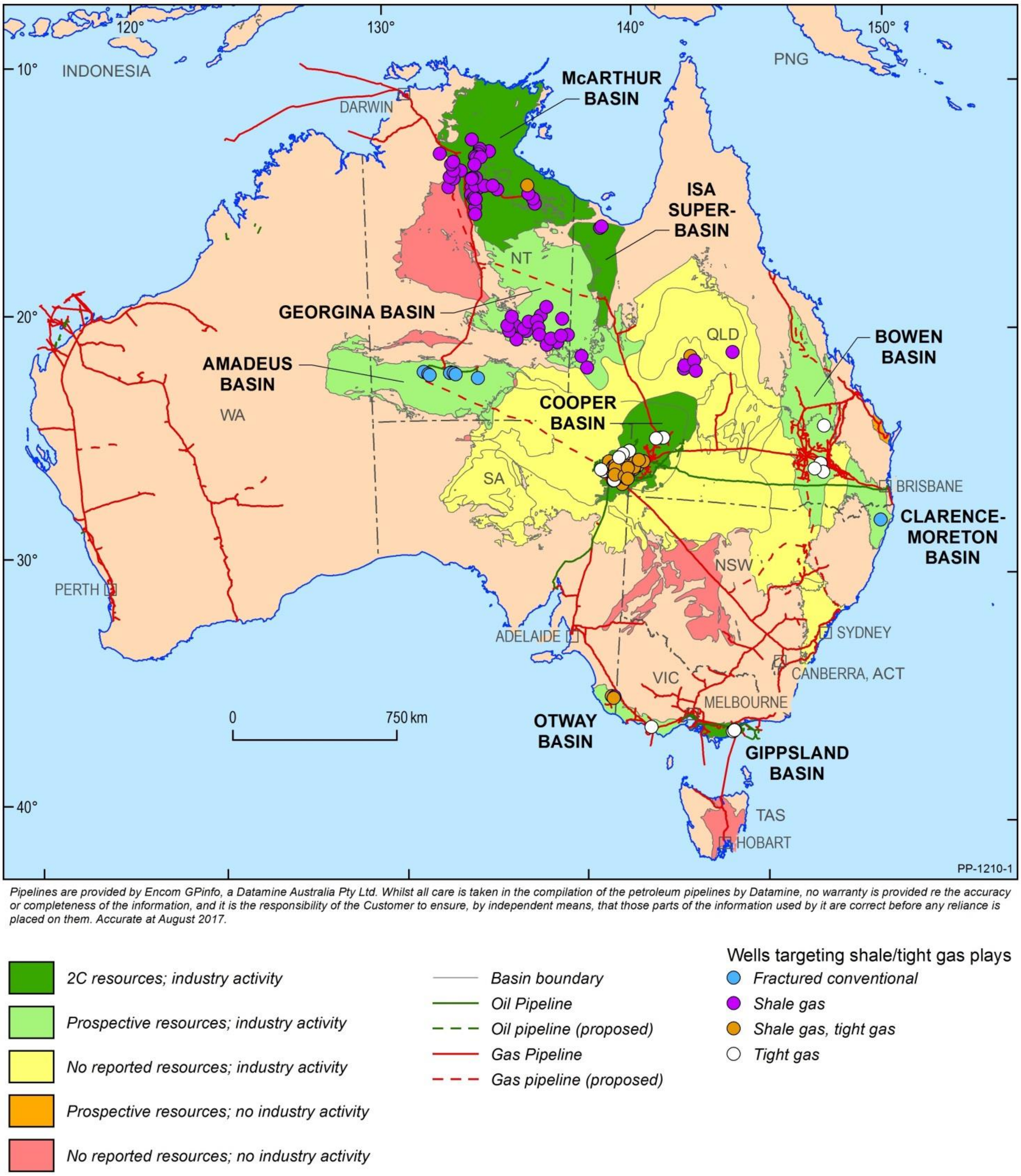


Figure 5-3 Australian basins classified by level of exploration activity for shale/ tight gas. Labelled sedimentary basins are those with reported 2C or prospective resources and on-going industry activity (as permitted by current regulatory environments). Basin outlines are sourced from Stewart et al. (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 5-2 Shale and tight gas exploration status of Australian basins based on AERA (2018) and additional references presented in Appendix A. Note basins with no reported resources and no industry activity were excluded. *AWT International (2013) reported prospective resources for the Toolebuc Formation shale gas play in the Eromanga Basin, but subsequent drilling results were poorer than expected so this number is now considered unreliable and has been disregarded for this study. **Contingent resources have been booked in the Galilee Basin (Comet Ridge, 2017), however it is unclear what proportion of this (if any) represents tight rather than conventional gas. ***Assuming a generic 10% recovery factor on reported gas-in-place for comparison purposes.

Basin	State	2C resources (Tcf)^	Potentially recoverable gas-in-place (Tcf)	Industry activity	Possible development timeframe	Include in basin audit
Cooper Basin	SA, QLD	9.58	58	Appraisal/ minor past production	5–8 years	Yes
Isa Superbasin	QLD, NT	0.15	22	Early appraisal	5–10 years	Yes
McArthur Basin	NT	6.6	20.2***	Early appraisal	5–10 years	Yes
Gippsland Basin (Onshore)	VIC	0.72	19.2	Early appraisal	5–10 years	Yes
Bowen Basin	QLD	0	97	Exploration	8–10 years	Yes
Georgina Basin	NT, QLD	0	50	Exploration	8–10 years	Yes
Otway Basin (Onshore)	SA, VIC	0	7.4	Exploration	8–10 years	Yes
Amadeus Basin	NT	0	26	Exploration	8–10 years	Yes
Clarence-Moreton Basin	QLD, NSW	0	21	Exploration	8–10 years	Yes
Pedirka Basin	NT,SA	0	34	No exploration activity	>10 years	No
Gunnedah Basin	NSW	0	13	No exploration activity	>10 years	No
Maryborough Basin	QLD	0	7	No exploration activity	>10 years	No
Galilee Basin	QLD	0**	0	?Preliminary exploration	>10 years	No
Eromanga Basin	NT, SA, QLD	0	0*	Exploration activity ceased due to poorer than expected results	>10 years	No
TOTAL		17.1	393.1			

Although documented contingent and prospective resource numbers provide a useful guide for both the prospectivity of a basin and its stage within the exploration cycle (Table 6-3), inconsistencies in resource assessment methodologies and reporting are significant and the following issues need to be considered when using these data.

- Contingent resources are independently assessed but still need to be considered carefully. For example, a gross 2C resource of 6.6 Tcf (approximately 7,260 PJ) has been reported by Origin Energy in the McArthur Basin based on the results of only 1 well, with a recovery factor of 16% (Close et al., 2017; Origin Energy, 2017). This is an important result, but uncertainties remain large and further testing is required (Revie, 2017a, b).

- The uncertainties in prospective resource volumes are greater still, as these numbers are based on much more limited information. It is also difficult to compare and contrast prospective resource estimates from different sources due to significant differences in both assessment method and area.
- Public domain prospective resource estimates are not available for all play types of interest. For example, no tight gas prospective resources have been estimated for the basin-centred gas play in the Taroom Trough (Bowen Basin), despite similarities with the Nappamerri Trough in the Cooper Basin.

Due to these inconsistencies, resource estimates cannot be used to directly rank the relative shale/ tight gas prospectivity of these nine basins. To more fully and effectively assess the shale and tight gas prospectivity of each of these basins, additional information on the regional geology and petroleum prospectivity must be taken into consideration.

5.2 Data inventory

A review of existing open file national scale, petroleum and environmental data and information was undertaken and used to underpin the geological and bioregional audit of the shortlisted basins. Regional scale data were also included where no national scale dataset contained the relevant information.

Data compilation was undertaken in two stages, as follows.

- Relevant datasets compiled for the original Bioregional Assessment Program were identified and checked for currency.
- Additional geological and petroleum datasets were identified and incorporated into the existing Bioregional Assessment data structure for use in the basin audit. New datasets included petroleum wells, 2D seismic navigation data, 3D seismic survey locations, oil and gas pipelines and petroleum processing facilities.

The data inventory and analysis involved the collection, spatial analysis and interpretation of a number of existing national datasets relevant to regional geology, petroleum exploration, groundwater, surface water, environmental assets and social factors.

Where possible, the most recent data has been used. In some cases, an older dataset provides better spatial coverage and consistency, licensing conditions or applicability. The datasets considered as part of this assessment were limited to those that were considered appropriate and were publically available at the time of draft preparation (August 2017). To enable sufficient time for analysis, datasets were downloaded or acquired in July and August 2017.

The datasets provide information on a range of factors seen as pertinent in the Rapid Regional Basin Prioritisation Phase. They inform aspects relating to groundwater, surface water, environmental assets and social factors. The rationale for the use of these datasets as well as a brief description of the assessment undertaken with each is provided in the following sub-sections. Table 5-3 and Table 5-4 present summaries of the datasets used. Maps of the datasets are presented in Appendix B (Figures B.1–B.19) and Appendix C. To augment the national-scale data, a brief literature review was undertaken for each basin. This literature review focused on: regional geology, petroleum exploration, hydrogeology and groundwater resources, surface water systems, and groundwater–surface water interactions.

A full list of the datasets incorporated in the data inventory can be found in Table 5-3 and Table 5-4 and all regional maps referred to in the data audit can be found in Appendix B. It is expected that in future stages of assessment, the range of factors and analysis undertaken will be broadened as basin shortlisting is progressed. Reviews of each basin, as well as tabulated results compiled from the national datasets are provided in the Appendix C of this report.

5.2.1 Topographic datasets

Administrative boundaries and infrastructure

Both administrative boundaries and infrastructure (road and rail) shown on the infrastructure maps in Appendix C were sourced from the Australian Topographic Base Map (Web Mercator) MapServer. The Australian Topographic base map service is a seamless national dataset coverage for the whole of Australia. The map is a representation of the GA 1:250k topographic specification and portrays a detailed graphic representation of features that appear on the Earth's surface.

Digital elevation data

The GEODATA 9 Second Digital Elevation Model (DEM-9S) Version 3 is a grid of ground level elevation points covering the whole of Australia with a grid spacing of 9 seconds in longitude and latitude (approximately 250 metres) in the GDA94 coordinate system (Hutchison et al., 2008).

5.2.2 Geological datasets

Geologic Provinces

To identify the areas of interest, the extent of the sedimentary basin associated with the potentially prospective shale and/or tight gas areas was used as the extent for analysis. These sedimentary basins are compiled within the Australian Geological Provinces dataset, along with other geological provinces such as orogenic belts. The nine chosen sedimentary basins (see Section 5.1) were extracted from the Australian Geological Provinces (Stewart et al., 2013). It was decided to use the entire polygon area for each province as the areas of interest for further analysis conducted for this report. These outlines provide a clipping and analytical extent for the various other datasets considered in this stage.

Surface Geology

The surface geology used in each basin location map in Appendix C is sourced from either the Surface Geology of Australia 1:1M scale dataset (2012 edition) (Raymond et al., 2009) or 1:2.5M (2012 edition) (Raymond et al., 2012). These are seamless national coverages of outcrop and surficial geology. The data maps outcropping bedrock geology and unconsolidated or poorly consolidated regolith material covering bedrock. Geological units are represented as polygon and line geometries, and are attributed with information regarding stratigraphic nomenclature and hierarchy, age, lithology, and primary data source. The dataset also contains geological contacts, structural features such as faults and shears, and miscellaneous supporting lines like the boundaries of water and ice bodies.

5.2.3 Petroleum datasets

Petroleum wells

Petroleum well header data was sourced directly from the state and territory government websites. A full list of data sources can be found in Table 5-3. The national scale distribution of petroleum wells is shown on Figure 5-4, while the data coverage maps in Appendix C show the distribution of petroleum well data within each shortlisted basin in greater detail.

Seismic data

Both 2D seismic navigation and 3D seismic areas for each state were sourced directly from the state and territory government websites. Navigation data for deep crustal seismic was also included within the inventory, where available. A full list of data sources can be found in Table 5-3. The national scale distribution of 2D seismic data is shown on Figure 5-4, while the data coverage maps in Appendix C show the distribution of all seismic data within each shortlisted basin in greater detail.

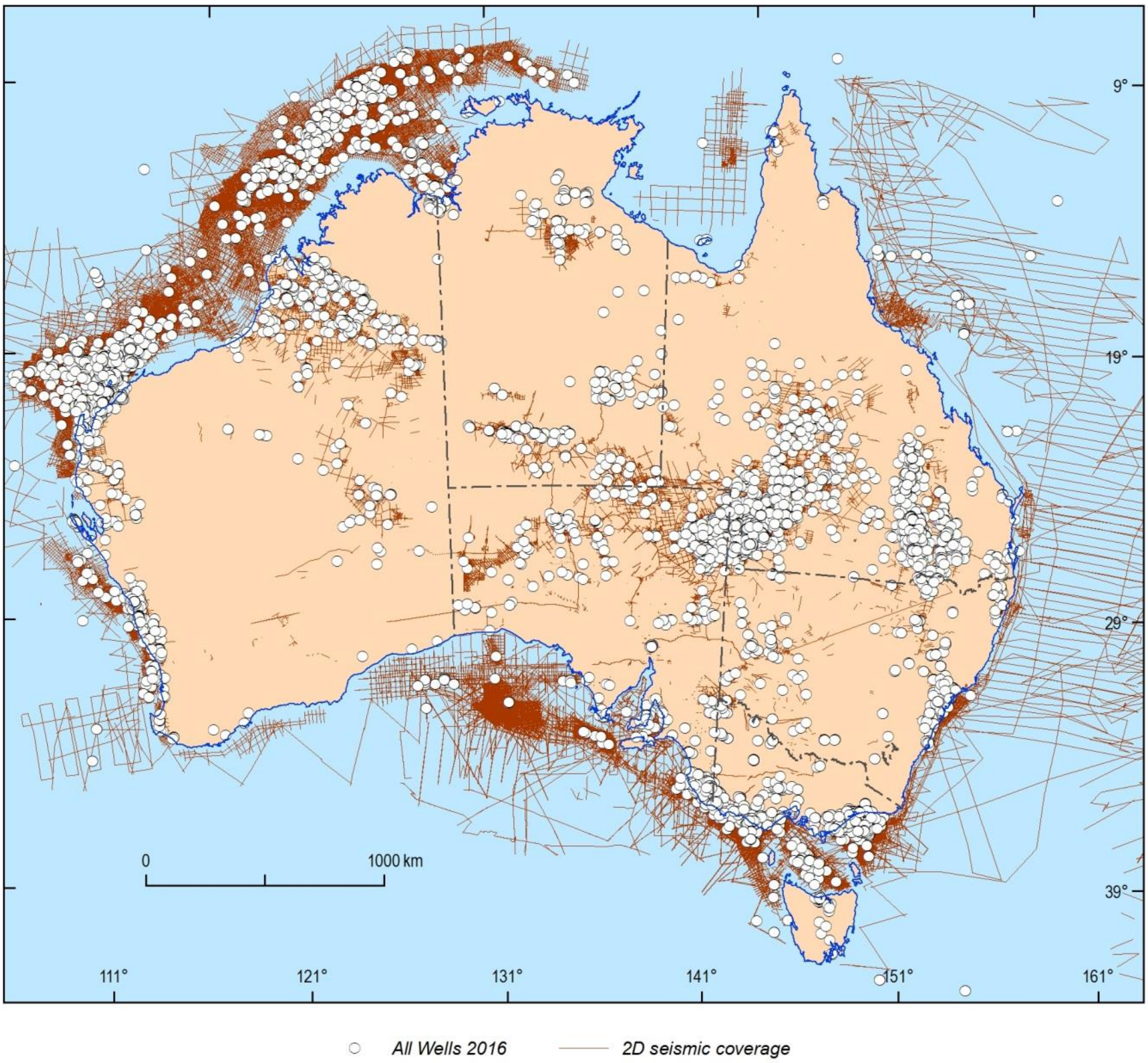


Figure 5-4 Distribution of petroleum wells and 2D seismic data across Australia.

Oil and gas pipelines

The National Onshore Gas Pipelines Dataset represents the spatial locations of pipelines for the transmission of natural gas within mainland Australia complimented with feature attribution (GA, 2015).

Gas processing facilities

The location of gas processing facilities is extracted from the Offshore Oil and Gas Platforms dataset, which includes infrastructure facilities for the extraction, processing and/or storage of oil and natural gas (GA, 2015b).

Field Outlines

Field outlines shown in the basin audit images are sourced from Encom GPInfo, a Pitney Bowes Software (PBS) Pty Ltd product. Although 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 users to ensure, by independent means, that those parts of the information used by it are correct before any reliability is placed on them.

Table 5-3 National-scale datasets relating to geology and petroleum used in this report, indicating the sources and the date when the datasets were downloaded. A full list of the datasets incorporated in the data inventory can be found in Appendix B.

Information	Dataset	Description	Reference	Website link or ISBN	Date downloaded	Refer to map in Appendices
Extent of sedimentary basins	Geological province extents	Australian Geological Provinces, 2013.01 edition, Geoscience Australia	Stewart et al. (2013)	www.ga.gov.au/metadata-gateway/metadata/record/74371	18/07/2017	Depicted on all regional maps.
Geological Map	Geological Map	Surface Geology of Australia 1:1 million scale dataset 2012 edition, Geoscience Australia	Raymond (2009)	https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=69455	11/08/2017	Appendix C – location maps
Geological Map	Geological Map	Surface Geology of Australia 1:2.5 million scale dataset 2009 edition, Geoscience Australia	Raymond et al. (2012)	https://data.gov.au/dataset/surface-geology-of-australia-1-1-million-scale-dataset-2012-edition	11/08/2017	Appendix C – location maps
2D seismic navigation	NSW Seismic lines	Seismic lines	GSNSW (2017)	https://minview.geoscience.nsw.gov.au/#/?bm=bm2&z=6&lat=148.9143431&lon=-32.6560775&l=gp8:y:100	29/08/2017	Appendix C – data distribution maps
Petroleum well header	Petroleum well header	Collar information for mineral and coal drill holes, and petroleum wells (including coal seam gas) that are recorded in the Mineral Resources' drilling database.	DREMP (2017)	http://dwh.minerals.nsw.gov.au/CI/warehouse	29/08/2017	Appendix C – data distribution maps
2D seismic navigation	Northern Territory Statewide Geophysics - Seismic Lines	seismic survey lines shot in the Northern Territory of Australia on land and over coastal waters (2 or 3D), Department of Primary Industry and Resources	NTGS (2017a)	http://www.ntlis.nt.gov.au/metadata/export_data?type=html&metadata_id=FB25348A02CB16B2E040CD9B2144584B	23/07/2017	Appendix C – data distribution maps
Petroleum well header	Petroleum well header - NT	Geoscience exploration and mining information system (GEMIS) – Petroleum wells	NTGS (2017b)	http://www.geoscience.nt.gov.au/gemis/ntgsjspui/handle/1/79187	23/07/2017	Appendix C – data distribution maps
2D seismic navigation	Seismic survey 2D - Queensland	Department of Natural Resources and Mines (2017), The location of lines along which 2D seismic reflection surveys have been acquired by exploration companies in Queensland	DNRME (2017a)	http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid={13A3258F-6E27-443C-A956-9DD5DA41E3CC}	11/08/2017	Appendix C – data distribution maps

Information	Dataset	Description	Reference	Website link or ISBN	Date downloaded	Refer to map in Appendices
Petroleum well header	Petroleum well locations - Queensland	Location of petroleum wells to identify where petroleum exploration and production wells have been drilled in Queensland.	DNRME (2017b)	http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid=%7bCBBE665F-60A8-4116-87C8-AEBF0D21B97C%7d	11/08/2017	Appendix C – data distribution maps
3D seismic surveys	Seismic survey 3D - Queensland	Department of Natural Resources and Mines (2014), The areas in which 3D seismic reflection surveys have been acquired by exploration companies in Queensland.	DNRME (2017c)	http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid={9D42C49B-4C83-490F-870C-7E2AB376CF86}	11/08/2017	Appendix C – data distribution maps
Deep crustal seismic surveys	Seismic survey deep - Queensland	Department of Natural Resources and Mines (2014), Line locations of deep crustal seismic reflection surveys that have been conducted in available Queensland	DNRME (2017d)	http://qldspatial.information.qld.gov.au/catalogue/custom/detail.page?fid={49ABBD21-C752-4D88-847B-6C85B9B6E867}	11/08/2017	Appendix C – data distribution maps
3D seismic surveys	3D Seismic Survey Areas	Department of State Development, Resources and Energy (2017), Location of ground traverses along which seismic surveys have been carried out as part of geophysical exploration for petroleum resources and research studies	DPCSA (2017a)	https://map.sarig.sa.gov.au/	27/07/2017	Appendix C – data distribution maps
2D seismic navigation	Seismic lines	Location of ground traverses along which seismic surveys have been carried out as part of geophysical exploration for petroleum resources and research studies.	DPCSA (2017b)	https://map.sarig.sa.gov.au/	4/09/2017	Appendix C – data distribution maps
Petroleum well header	Petroleum Wells	Department of State Development, Resources and Energy (2017), Department of State Development, Resources and Energy	DPCSA (2017c)	https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/catapp/sarig/cat/Record;jsessionid=EE0C9DD86F81E2C6E6FB298C99D568AD	27/07/2017	Appendix C – data distribution maps
2D seismic navigation	Seismic Survey Lines - for Petroleum Industry Exploration	Seismic Survey Lines - for Petroleum Industry Exploration, Geological Survey Victoria	GSV (2017a)	https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/catapp/sarig/cat/Record	11/08/2017	Appendix C – data distribution maps

Information	Dataset	Description	Reference	Website link or ISBN	Date downloaded	Refer to map in Appendices
3D seismic surveys	Seismic 3D Survey Areas - for Petroleum Industry Exploration	The polygons depict the outline of 3D surveys. These outlines illustrate the survey outlines but are not consistently defined. Geological Survey Victoria	GSV (2009)	http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002766&extractionProviderId=1	11/08/2017	Appendix C – data distribution maps
Petroleum well header	Petroleum Wells.	Petroleum Wells (from Minerals and Petroleum's DbMap database), Geological Survey Victoria	GSV (2017b)	http://services.land.vic.gov.au/SpatialDatamart/viewMetadata.html?anzlicId=ANZVI0803002954&extractionProviderId=1	11/08/2017	Appendix C – data distribution maps
Oil and gas pipelines	National Oil and Gas Infrastructure	Web service providing access to the National Oil and Gas Infrastructure datasets. These datasets present the spatial locations of onshore oil and gas pipelines for the transmission of oil and gas within mainland Australia. They also present the location of oil and gas platforms within Australia's territorial waters.	GA (2015a)	http://services.ga.gov.au/site_9/rest/services/Oil_Gas_Infrastructure/MapServer	23/07/2017	Appendix C – infrastructure maps
Gas processing facilities	Offshore oil and gas platforms	Point dataset containing offshore Oil and Gas Platforms located in Australian waters that include infrastructure facilities for the extraction, processing and/or storage of oil and natural gas.	GA (2015b)	https://ecat.ga.gov.au/geonetwork/srv/eng/search#!0a4a79dc-978a-0e89-e054-00144fdd4fa6	23/07/2017	Appendix C – infrastructure maps

5.2.4 Groundwater, surface water, environmental assets and social datasets

Maps of the datasets described below are presented in Appendix B Regional Maps.

5.2.4.1 **National hydrogeology**

The national hydrogeology dataset (Jacobsen and Lau, 1987) provide the framework of national hydrogeology by describing areas over the entire country as one of five categories: extensive highly-productive porous aquifers; extensive low-moderate productivity porous aquifers; extensive highly-productive fractured or fissured aquifers; extensive low-moderate productivity fractured or fissured aquifers; and local aquifers of low productivity. Highly productive aquifers are defined as having “extensive aquifer distribution with most bore yields greater than 5 Litres per second (L/s)”; Low-moderate productivity is defined as having “extensive aquifer distribution with most bore yields of 0.5–5 L/s”; while a low classification is defined as having “local aquifer distribution, bore yields less than 0.5 L/s”. Whilst being a broad-scale dataset, the nationally consistent approach allows for inter-basin comparisons. More detailed hydrogeological information is presented for individual basins in the Basin Audit (Appendix C).

5.2.4.2 **Groundwater bores**

Groundwater bores provide insights into the groundwater system. Measurements taken from the bores provide information on groundwater quality, quantity, and flow directions. Bore construction records provide information on the lithology, purpose, bore depth and casing information. To obtain the location and information about groundwater bores, a national dataset known as the National Groundwater Information System (NGIS), version 1.3, was used (BoM, 2016). The NGIS contains a nationwide inventory on groundwater bores that have been registered with the relevant State or Territory Authority with sufficient information to allow the national compilation. For this phase of work, analysis was undertaken on all bores within the NGIS regardless of usage (operational or not). Future stages of work will require a more detailed assessment of bores within the dataset.

5.2.4.3 **Groundwater bore density**

Groundwater bore density was used to elucidate the current state of groundwater bore development in each basin. It is recognised that having many bores indicates a high likelihood of finding groundwater, but also a high likelihood of that groundwater is being used. The Australian Groundwater Insight bore density grid was obtained at 25 km^2 resolution (BoM, 2015).

5.2.4.4 **Bore depth**

To provide an indication of the depth of the aquifers being tapped, the bore depth (metres below ground level) was used. It has been assumed that in most cases, drilling of a bore would stop once a sufficient water supply had been found. As such, it has been assumed that the bore depth is a useful proxy in representing the aquifer depth. In calculating bore depth statistics, all bores shallower than 2 m were excluded from calculations: this was done to exclude what was considered to be incorrectly entered data.

5.2.4.5 Groundwater salinity

A significant number of the bores in the NGIS had groundwater salinity values (measured in electrical conductivity (EC) as microsiemens per centimetre, µS/cm) associated with them. Electrical conductivity is a simple and commonly used method for estimating water salinity. The number of measurements for each bore was highly variable, and ranged from a single measurement up to thousands of measurements. To facilitate mapping and identifying spatial trends, the average salinity value for each bore was taken.

The electrical conductivity data was converted into total dissolved solids (TDS) expressed in mg/L, a commonly reported salinity unit. For this purpose a conversion factor of 0.64, as suggested by the Australian Drinking Water Guidelines (NHMRC and NRMMC, 2011), was used.

5.2.4.6 Wetlands

Wetlands have a strong relationship to the water cycle and are often intimately linked with groundwater springs or surface water systems. Wetlands are a surface expression of groundwater systems and groundwater–surface water interactions. They are also a critical part of the natural environment: they protect waterways in terms floods and water quality, provide habitat for noteworthy ecosystems, and have aesthetic, social, economic and cultural values (DoEE, 2017). For this assessment, both Ramsar wetlands (DoEE, 2016a) and those listed under the Directory of Important Wetlands in Australia (DIWA) were considered (DEWHA, 2010).

Ramsar wetlands are those that are rare or unique wetlands, or are important for conserving ecological diversity. These are included on the List of Wetlands of International Importance developed under the Ramsar convention, and catalogued as Australian Ramsar Wetlands (DoEE, 2016a).

The Directory of Important Wetlands in Australia (DIWA) provides a list of nationally significant wetlands (DEWHA, 2010). For a wetland to be listed in DIWA, it must meet at least one of the following criteria:

- A good example of a wetland type occurring within a biogeographic region in Australia.
- A wetland which plays an important ecological or hydrological role in the natural functioning of a major wetland system/complex.
- A wetland which is important as the habitat for animal taxa at a vulnerable stage in their life cycles, or provides a refuge when adverse conditions such as drought prevail.
- The wetland supports 1% or more of the national populations of any native plant or animal taxa.
- The wetland supports native plant or animal taxa or communities which are considered endangered or vulnerable at the national level.
- The wetland is of outstanding historical or cultural significance.

For this assessment, the spatial coverage of both the Ramsar wetlands and DIWA wetlands were overlaid on the geological basins to provide coverage maps.

5.2.4.7 **Groundwater dependant ecosystems**

The Bureau of Meteorology has published an Atlas of Groundwater Dependant Ecosystems (GDE Atlas; BoM, 2017). Data from this atlas was used to identify GDEs in the nine basins.

Groundwater Dependant Ecosystems (GDEs) by nature are intimately linked with groundwater springs or other subsurface source of water and therefore vulnerable to changes in the hydrological cycle.

Two categories of GDE in the atlas were used for analysis:

- "Aquatic ecosystems": these rely on the surface expression of groundwater, and include rivers, wetlands and springs
- "Terrestrial ecosystems": these rely on the subsurface presence of groundwater, such as vegetation. As such, the majority of the landmass is covered by some kind of terrestrial GDE indication

A third category, "subterranean ecosystems" which include cave and stygofauna, was not included as it has not been mapped nationally.

From the GDE Atlas (BoM, 2017), the calculated total area with at least a moderate potential for GDEs (i.e. also including high potential and known classifications), either from national or regional studies, were summed. All of the areas within these classes are treated identically. The total area of aquatic and terrestrial ecosystems with at least moderate potential has been calculated.

Given the many of the methods for compiling this atlas are based on regional and remotely-sensed techniques, it is acknowledged that that there may be other areas, on smaller scales, that are not depicted in this atlas. Also, it is acknowledged that there has been no consideration into the relative value of ecosystems within this atlas – it is possible that some are critical to important species, while others are just a small area of the habitat for far-reaching species. However, such an assessment beyond the level of GDE potential and likelihood, and given the data available in the GDE Atlas, would be highly subjective – as such, it was decided to treat all the area of GDE with at least a moderate potential as equal.

5.2.4.8 **Protected areas**

To highlight areas where national parks and other protected areas could affect the prospect of development, a spatial representation of these reserves was used. Although many parks are managed by state/territory governments, the Collaborative Australian Protected Area Database (CAPAD) has compiled these across the country (DoEE, 2016b). As such, it is a nationally-consistent framework to depict these protected areas. There are many categories in the database, with some existing only in certain states/territories, as differences in laws between states/territories require such classification. As such, the analysis provided for this report has not made a distinction between these types. It is acknowledged that areas such as World Heritage Areas and National Parks may be of greater importance than some Regional Parks and Nature Refuges; however, for the purpose of this analysis, the total area has been considered as a whole. This means that the reported values from this analysis are assisting understanding the area that has some kind of protection, without assuming any quantified relative importance of these types. Indigenous

Protected Areas were not considered as part of this analysis: these areas were mapped with Native Title areas.

5.2.4.9 **Native title and indigenous protected areas**

National data layers representing Native Title (not including Aboriginal freehold land) and declared Indigenous Protected Areas were overlain to show the spatial distribution of these in the basins of interest. Data was sourced from the Indigenous Protected Areas of the CAPAD dataset (DoEE, 2016b) as well as from the Native Title Determination Outcomes (both exclusive and non-exclusive native title) from the National Native Title Tribunal (NNTT, 2017).

Native Title does not confer legislative protection to areas per se, but many determinations allow Indigenous Australians who hold native title, or who have a pending native title claim, the right to be consulted and, in some cases, to participate in decisions about activities proposed to be undertaken on the land (NNTT, 2017).

5.2.4.10 **Population and population density**

The population density grid was used to show the population distribution within the basins and used to estimate total population (ABS, 2016). This represents levels of urbanisation and intense development.

5.2.4.11 **Land use**

A spatial representation of land uses has been included to indicate what areas are covered by existing land uses that may conflict with the ability for shale and tight gas to be developed. A national classification framework has been developed as part of the Australian Collaborative Land Use and Management Program (ACLUMP), which lead to the Catchment-scale Land Use Mapping (CLUM) dataset (ABARES, 2016). Although there are finer-scale details that alter this, the CLUM dataset is a nationally-consistent framework. For this analysis, the total area of each category of land use encountered in each basin has been calculated, allowing a percentage of basin coverage list to be tabulated. Some land uses are more likely to create conflict than others; however, for the purposes of this analysis, a list of the land use classes with the greatest area has been compiled.

5.2.4.12 **River catchment areas**

To determine the river systems overlying the basins of interest, the catchment areas for rivers were required. A nationally-mapped categorisation of drainage divisions (level 1) and river regions (level 2) has been included in the Australian Hydrological Geospatial Fabric (“Geofabric”), as produced by the Bureau of Meteorology (BoM, 2014). Each river region is named after the major river in the area. The main purpose of reporting these river regions is to inform the surface water hydrology.

Table 5-4 National-scale datasets relating to ground water, surface water, environmental assets and social factors used in this report, indicating the sources and the date when the datasets were downloaded.

Information	Dataset	Source	Website link or ISBN	Date downloaded	Refer to map in Appendix B:
Extent of sedimentary basins	Geological Province extents	GA (2013): Australian Geological Provinces, 2013.01 edition	www.ga.gov.au/metadata-gateway/metadata/record/74371	18/07/2017	Depicted on all regional maps.
National Hydrogeology	Hydrogeology: Principal aquifer type	Jacobson and Lau (1987), Hydrology of Australia, Geoscience Australia.	https://ecat.ga.gov.au/geonetwork/srv/eng/search#!a05f7892-72bf-7506-e044-00144fdd4fa6	10/07/2017	National Hydrogeology – Figure B.1
Groundwater bores	NGIS registered bores	BoM (2016), National Groundwater Information System, v.1.3.	http://www.bom.gov.au/water/groundwater/ngis/	7/07/2017	NGIS (Bore Depth) – Figure B.2 NGIS (Salinity) – Figure B.3
Density of bores	Grid of density of NGIS bore points	BoM (2015) Australian Groundwater Insight – Bore density 2015	http://www.bom.gov.au/water/groundwater/insight/#/bore/density	18/07/2017	NGIS (Bore Density) – Figure B.4
Wetlands of international importance	Declared Ramsar wetlands	DoEE (2016a): Australian Ramsar Wetlands	http://www.environment.gov.au/fed/catalog/search/resource/downloadData.page?uuid=%7B3F208CDF-28ED-4B1F-B965-A733EB58D952%7D	19/07/2017	Wetlands – Figure B.5
Wetlands of national importance	Directory of Important Wetlands in Australia	DEWHA (2010): A Directory of Important Wetlands in Australia (DIWA) Spatial Database, third edition	http://www.environment.gov.au/fed/catalog/search/resource/details.page?uuid=%7BE6C815D9-FB67-4372-AC25-81C7473CCD21%7D	10/08/2017	Wetlands – Figure B.5
Spatial representation of groundwater-dependent ecosystems	GDE Atlas	BoM (2017): Groundwater Dependent Ecosystems Atlas	http://www.bom.gov.au/water/groundwater/gde/map.shtml	28/07/2017	Groundwater Dependant Ecosystems – Figure B.6
Extent of protected areas	CAPAD polygon areas	DoEE (2016b): Collaborative Australian Protected Area Database	https://www.environment.gov.au/land/nrs/science/capad/2016	18/07/2017	Collaborative Australian Protected Areas – Figure B.7
Native Title	Areas where Native Title exists	NNTT (2017): Native Title Determination Outcomes	http://www.ntv.nntt.gov.au/intramaps/download/download.asp	7/7/2017	Native Title and Indigenous Protected Areas – Figure B.8

Information	Dataset	Source	Website link or ISBN	Date downloaded	Refer to map in Appendix B:
Population density	Population density grid	ABS (2016): Australian Population Grid	http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/3218.02015-16?OpenDocument	7/07/2017	Population Density – Figure B.9
Land use	CLUM	ABARES (2016): Catchment-scale Land Use Mapping of Australia	http://data.gov.au/dataset/catchment-scale-land-use-of-australia-update-may-2016	18/07/2017	Land use – Figure B.10
Rivers and Catchments	Geofabric	BoM (2014): Australian Hydrological Geospatial Fabric (“Geofabric”), version 2.1.1	http://www.bom.gov.au/water/geofabric/download.shtml	2/08/2017	Surface Water – Figures B.11–.19

5.3 Audit of shortlisted basins

A rapid audit was then undertaken on the shortlisted basins (Figure 5-5) in order to prioritise areas for further research (Appendix C). This process aimed to:

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

The audit was conducted based on the following rapid regional rapid prioritisation criteria as agreed by GA and the DoEE, and hence contains a brief summary of the following topics for each shortlisted 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 moratoria; exploration moratoria.
- **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, environmental conditions and potential stressors. The results of each prioritisation theme are clearly presented in tables, maps, matrices and within the basin summary documents in Appendix C for the DoEE's consideration when deciding on priority areas for further geological and bioregional assessment work.

Figure 5-5 Location of shortlisted onshore basins considered for audit.

5.3.1 *Basin geology, prospectivity, market infrastructure access and regulatory environment*

The initial basin shortlist was developed based on the stage of industry activity and reported resource information. However, as previously discussed, uncertainty in the estimates reported means basins cannot be ranked directly based on this data alone. As a result, the audit of geology and prospectivity information for each shortlisted basin provides the additional information required to effectively evaluate which basins have the greatest shale and tight gas prospectivity.

5.3.1.1 Basin geology and prospectivity summaries

Each audit summarised the basin geology and prospectivity, and included the following information:

- play type;
- petroleum systems;
- source rock and reservoir formations, lithology, depositional environment, age and depth; and,
- source rock characteristics (e.g. TOC, HI, maturity, kerogen type).

This section presents a synthesis of the basin geology and shale and tight gas prospectivity results of the basin audit. Further details and references are presented for each of the nine basins in Appendix C.

5.3.1.1.1 **Amadeus Basin**

The Neoproterozoic to Late Devonian Amadeus Basin is located mainly in the Northern Territory. It contains up to 14 km of clastic, carbonate and evaporitic sedimentary rocks that were deposited in shallow marine to continental environments (Edgoose, 2013; Munson, 2014). The basin is a producing hydrocarbon province currently supplying gas and oil to Darwin. Unconventional exploration interest is focused on shale and tight gas plays in the upper Cambrian-lower Ordovician Larapinta Group (Central Petroleum, 2017). No contingent shale or tight gas resources have been recorded for the basin, although a total mean prospective technically recoverable resource of 26.2 Tcf of gas has been estimated for the lower Larapinta Group (AERA 2018). This includes 11.3 Tcf of shale gas in the Horn Valley Siltstone (prospective area 7,395 km^2), 9.8 Tcf of tight gas in the Pacoota Sandstone (prospective area 3,440 km^2) and 5.1 Tcf of tight gas in Stairway Sandstone (prospective area 3,440 km^2) (DSWPET, 2011).

5.3.1.1.2 **Bowen Basin**

The Permian–Triassic Bowen Basin is located in southeastern Queensland and extends into northern New South Wales. The basin contains up to 10 km of shallow marine to terrestrial clastic sediments including important coal resources, and is overlain by the Surat Basin (Korsch and Totterdell, 2009; Jell, 2013). The Bowen Basin succession contains multiple proven and potential source rocks, particularly within the upper Permian coal measures (DNRM, 2017). The basin is an established hydrocarbon province (Gondwanan petroleum system) hosting >100 conventional oil and gas discoveries and provides conventional and coal seam gas to the East Coast Gas Market. Unconventional exploration in the basin is at an early stage, with the focus on tight and some shale gas plays in the Taroom Trough. Prospective shale gas resources from the Black Alley Shale have been estimated at 97 Tcf over an area of 51,252 km^2 (AWT International, 2013; AERA, 2018).

5.3.1.1.3 Clarence-Moreton Basin

The Triassic–Cretaceous Clarence-Moreton Basin is located in northeastern New South Wales and southeastern Queensland, and adjoins the Surat Basin in the west. The basin contains up to 4 km of dominantly fluvio-lacustrine sedimentary rocks, and includes some rich potential source rocks (Wells and O'Brien, 1994). The basin is relatively poorly explored for conventional hydrocarbons, but drilling has resulted in abundant gas and minor oil shows and one discovery. Unconventional exploration is at a very early stage in the basin, with some tight gas intervals intersected in the lower Jurassic section. 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 an area of 4,407 km^2 (AWT International, 2013; AERA, 2018).

5.3.1.1.4 Cooper Basin

The upper Carboniferous–Middle Triassic Cooper Basin is located in northeastern South Australia and southwestern Queensland. The basin contains in excess of 4.5 km of dominantly fluvial–lacustrine sedimentary rocks, including thick coal measures, and is overlain by the Eromanga Basin (Gravestock et al,. 1998; Jell, 2013; Hall et al., 2015, 2016a). The Cooper–Eromanga Basin has a proven petroleum system (Gondwanan) and is Australia's premier onshore conventional hydrocarbon province, providing gas to the East Coast Gas Market. Currently, 256 gas fields and 166 oil fields are in production. The Cooper Basin also hosts a range of unconventional play types including basin-centred gas and tight gas, deep (> 2,000 m) coal gas, and shale gas plays (Goldstein et al., 2012; Hall et al., 2016b). There has been extensive exploration for both shale and tight gas in the South Australian part of the basin and a more limited amount in the Queensland portion. A total of 9.58 Tcf of 2C resources have been booked for the basin by a range of companies and potentially recoverable shale and tight gas-in-place resources are estimated at 7 Tcf and 51 Tcf respectively (refer to Appendix A for prospective areas; calculated with a 5% recovery factor at P50; AERA, 2018).

5.3.1.1.5 Georgina Basin

The Neoproterozoic–Devonian Georgina Basin is located in the Northern Territory and Queensland. The basin contains up to 4 km of marine, fluvial and glacial sediments. Although the basin is relatively under-explored, it contains rich marine source rocks and a proven Cambrian petroleum system (Larapintine) (Munson et al., 2013). Recent exploration in the Georgina Basin has mainly focused on unconventional hydrocarbons (Willink and Allison, 2015), with ~22 wells drilled in the southern Georgina Basin targeting shale oil, shale gas and basin-centred gas plays. However, drilling results to date have met with mixed success, and uncertainties due to lack of geological knowledge in this data poor area are considerable. Several regional scale prospective resource estimates have been published for shale gas plays in the Georgina Basin (e.g. DSWPET, 2011; AWT International, 2013); however these were conducted prior to recent drilling results.

5.3.1.1.6 Gippsland Basin (onshore)

The Cretaceous–Cenozoic onshore Gippsland Basin is located in eastern Victoria. The onshore basin contains up to 4 km of clastic and carbonate sedimentary rocks deposited in fluvial, deltaic and marine environments. The offshore part of the basin has a proven petroleum system (Austral 2 and 3) and is one of Australia's premier hydrocarbon provinces, hosting several giant oil and gas fields. Although numerous oil and gas shows have been recorded in wells drilled in the onshore part of the basin, no conventional discoveries have been made since relatively small volumes of oil were produced at Lakes Entrance in the 1920s and 1930s. Limited unconventional exploration has been undertaken in the onshore basin, targeting tight gas in the Lower Cretaceous Strzelecki Group in the Seaspray Depression (Goldie Divko, 2015), with 2C resources of ~0.72 Tcf reported for the Trifon-Gangell and Wombat accumulations (Lakes Oil, 2017). A recent volumetric study by Geoscience Australia based on publicly available data estimates the potentially recoverable tight and shale gas-in-place resources in the Strzelecki Group at 13.6 Tcf and 5.6 Tcf respectively (refer to Appendix A for prospective areas; calculated with a 5% recovery factor at P50; AERA, 2018). However if present, all prospective shale gas resources and any prospective tight gas resources located away from the Seaspray depression are considered to be speculative to be considered viable for development within a 10 year timeframe.

5.3.1.1.7 Isa Superbasin

The Paleo-Mesoproterozoic Isa Superbasin is located in northwestern Queensland and is part 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 the superbasin boundary remains very poorly defined. The basin contains a shallow to deep marine succession up to 15 km thick, which includes rich potential source rocks containing over 5% Total Organic Carbon (TOC) (Betts and Lister, 2001; Southgate et al., 2000). Although the superbasin is poorly explored and has sparse data coverage, it has recently been the focus for frontier conventional and unconventional gas exploration in the relatively undeformed northern part of the superbasin. Drilling of shale gas targets has been successful with gas flowing from a multi-stage, hydraulically stimulated shale formation. This has resulted in 0.15 Tcf of 2C resources begin booked for the basin, in addition to reported prospective resources of 22.1 Tcf for the Lawn Hill and Riversleigh Shale across permit ATP1087 (Armour Energy, 2017).

5.3.1.1.8 McArthur Basin

The Paleo-Mesoproterozoic McArthur Basin is located in the Northern Territory and Queensland; it includes the Beetaloo Sub-basin in the southwest. The McArthur Basin contains a mixed carbonate and siliciclastic succession approximately 12 km thick, which was deposited in shallow marine, fluvial and lacustrine environments (Munson, 2014). The basin contains several rich source rocks (including the Barney Creek, Velkerri and Kyalla formations) that have been the focus of unconventional exploration. More than 30 wells have been drilled, mainly in the Beetaloo Sub-basin where extended production testing of Amungee NW-1H led to the booking of a gross 2C resource of 6.6 Tcf (equivalent to a net share of 2.3 Tcf for Origin; Close et al., 2017; Origin Energy, 2017). 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).

5.3.1.1.9 Otway Basin (onshore)

The Jurassic–Cenozoic onshore Otway Basin is located in Victoria and extends into southeast South Australia. The basin contains a fluvio-lacustrine, deltaic and marine, carbonate and clastic succession up to 4 km thick (Krassay et al., 2004). The basin contains proven petroleum systems (Austral 1 and 2) and gas has been produced from conventional fields in Cretaceous sequences in the Penola Trough and Port Campbell Embayment. The majority of the 270 wells drilled in the onshore basin targeted conventional petroleum. Both the key conventional source rocks, and the main shale and tight gas targets, are the Casterton Formation–Crayfish Subgroup and Eumeralla Formation (Goldstein et al., 2012; Goldie Divko, 2015). The potentially recoverable, tight and shale gas-in-place resources are estimated at 5.8 Tcf and 1.6 Tcf respectively (refer to Appendix A for prospective areas; calculated with a 5% recovery factor at P50; AERA, 2018).

5.3.1.2 Basin geology and prospectivity prioritisation results

The results of the basin audit were used to assign a shale/ tight gas prospectivity ranking to each basin. Key factors considered in assessing regional shale and/or tight gas prospectivity included:

- overall petroleum prospectivity;
- estimated prospective resource area which with the potential to be developed within a ten year timeframe, where such information was available from existing public domain sources;
- prospective resources, and;
- shale/tight gas exploration success to date.

"Shale and/or tight gas prospectivity" ranks are defined below.

- **High:** overall prospectivity is high; large prospective resource area for shale/ tight gas which may be suitable for development in a ten year timeframe (>20,000 km^2); shale/ tight gas exploration success to date.
- **Moderate:** overall prospectivity is moderate; small prospective resource area for shale/ tight gas suitable for development in a ten year timeframe (>5,000 km^2); variable exploration success to date.

This ranking is qualitative and is based on the level of knowledge and available data for the given basin, as summarised in Table 5-5.

The confidence rankings are based on both the amount of data available within the basin and the quality of that data. Key factors considered in assessing regional shale and/or tight gas prospectivity included:

- basin area;
- number of petroleum wells and shale/ tight gas wells drilled to date;
- line km of seismic data;
- overall exploration status, and;
- shale/tight gas exploration status.

Less data with lower quality resulted in low confidence for the prospectivity ranking, whereas a high confidence was used to indicate the prospectivity rating is underpinned by more data. The petroleum data confidence ranking results are summarised Table 5-6.

Table 5-5 Summary of onshore basin prospectivity rankings. * Area based on formation extent only; ** Area based on formation and gas window extent.

Basin	Age	Petroleum system	Overall petroleum prospectivity	Basin Area (km^2)	Possible area of prospective resource	Success to date	Shale/ tight gas relative prospectivity ranking
Amadeus Basin	Neoproterozoic–Late Devonian	Larapintine, Centralian	High	180,000	Large*	Unknown	Moderate–high
Bowen Basin	Permian–Triassic	Gondwanan	High	154,000	Large**	Low–moderate	High
Clarence-Moreton Basin	Late Triassic–Early Cretaceous	?Murta	Moderate	38,000	Small**	Too few wells drilled	Low–moderate
Cooper Basin	?Pennsylvanian– Middle Triassic	Gondwanan	High	127,000	Large**	High: contingent resources booked	High
Georgina Basin	Neoproterozoic–Devonian	Larapintine	Moderate	330,000	Large*	Moderate	Moderate
Gippsland Basin (onshore)	Cretaceous–Cenozoic	Austral 2	Moderate	15,000	Small**	High: contingent resources booked	Moderate
Isa Superbasin	Paleoproterozoic–Mesoproterozoic	Undefined	Moderate–high	56,000	Large*	High: contingent resources booked	Moderate–high
McArthur Basin	Paleoproterozoic–Mesoproterozoic	Urapungan; McArthur	High	180,000	Large*	High: contingent resources booked	High
Otway Basin (onshore)	Jurassic–Cenozoic	Austral 1 and 2	Moderate–high	26,000	Medium**	High	Moderate–high

Table 5-6: Summary of onshore basin confidence rankings based on data density and overall exploration status.

Basin	Area (km^2)	No of petroleum wells	Approx. no of shale/ tight gas wells	Seismic line (km)	Exploration status - conventional	Exploration status – shale/tight gas	Confidence in geological knowledge
Amadeus Basin	180,000	~40	Unknown	12,986	Producing/ mature	Under-explored	Moderate
Bowen Basin	154,000	>300	>6	57,035	Producing/ mature	Preliminary exploration/ under-explored	Moderate
Clarence-Moreton Basin	38,000	~50	1	2,909	Exploration/ appraisal	Under-explored	Low–moderate
Cooper Basin	127,000	>3,000	>40	>81,000	Producing/ mature	Advanced exploration/ appraisal	High
Georgina Basin	354,000	>70	>22	11,767	Exploration/ appraisal	Preliminary exploration/ under-explored	Low–moderate
Gippsland Basin (Onshore)	11,500	198	>2	3,620	Producing/ mature	Appraisal	High
Isa Superbasin	56,000	~13	4	6,869	Under-explored	Appraisal/ under-explored	Low– moderate
McArthur Basin	285,000	~35	>33	7,823	Under-explored	Appraisal	Moderate
Otway Basin (Onshore)	26,500	~270	4	30,000	Producing/ mature	Exploration/ under-explored	High

Figure 5-6 provides a visual summary of the relative shale and/or tight gas prospectivity of the basins compared with the confidence we have of the current knowledge of the basins. From this assessment:

- The Cooper Basin is ranked high in terms of both prospectivity and confidence, reflecting the extensive exploration for shale and tight gas resources already undertaken in this basin.
- The McArthur, Bowen and Amadeus basins prospectivity ranks as high, based on the quality of known and potential source rocks, while confidence is only a moderate reflecting the basins' more limited exploration history.
- The Otway Basin ranks as moderate–high prospectivity and high confidence due to data density and quality.
- The Isa Superbasin prospectivity ranks as moderate–high due to the booked contingent resources, however confidence is low–moderate due reflecting the sparse data distribution and very limited exploration history.
- The Gippsland Basin is ranked moderate for prospectivity reflecting the relatively small area of potential unconventional gas resources which may reasonably be developed within a 10 year timeframe, however confidence is high due to data density and quality.
- The Georgina Basin is ranked as moderate in terms of prospectivity, reflecting the relatively poor results of recent exploration, with a low–moderate confidence reflecting sparse data distribution.
- The Clarence-Moreton Basin is ranked as low–moderate for both prospectivity and confidence, reflecting the relatively small prospective area, early stage of exploration and limited data.

These rankings could be improved with more data collection to increase the knowledge of the basin, and by conducting further studies as described in the basin recommendations list.

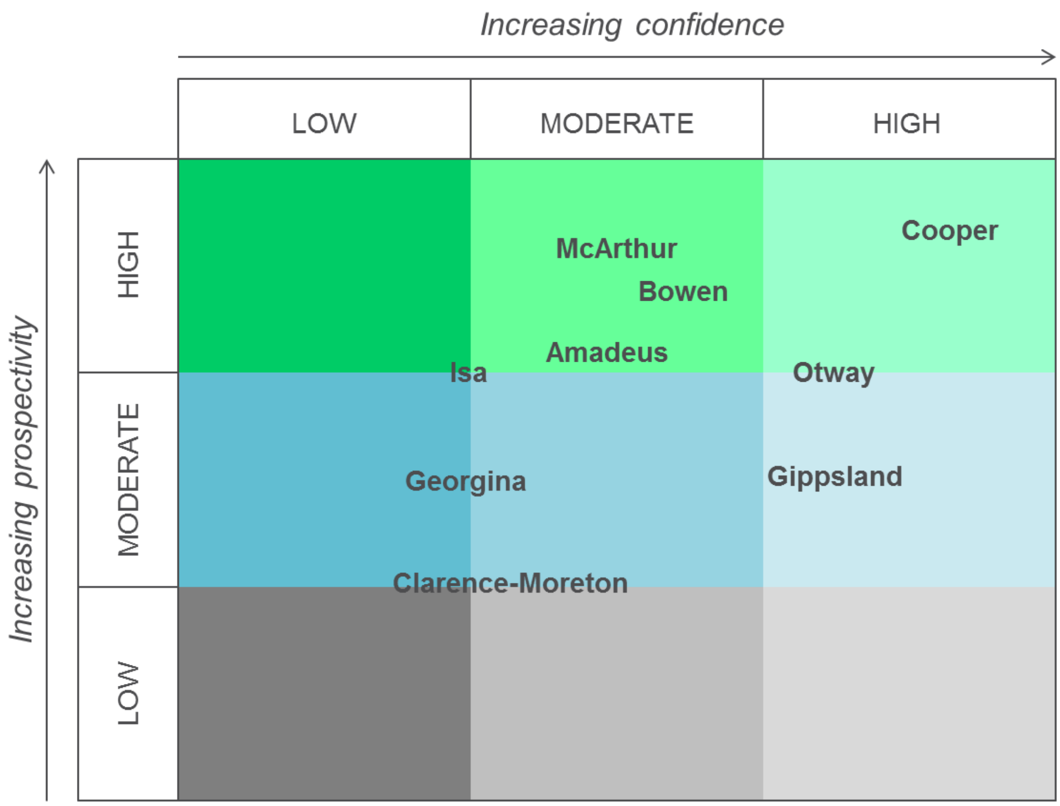


Figure 5-6 Shale/ tight gas prospectivity-confidence matrix for shortlisted basins.

5.3.1.3 Prioritisation based on market infrastructure access

The factors considered in assessing access to infrastructure and markets were:

- Proximity to the east coast gas market via pipelines
- Additional infrastructure requirements
- Processing/ storage facilities
- Road and rail access
- Townships

The results of the assessment are shown in Table 5-7 and Figure 5-7.

In assessing proximity to the East Coast Gas Market infrastructure, those basins already producing gas directly into the East Coast Gas Market were ranked highest. A pipeline linking northern and East Coast gas markets, scheduled to open by the end of 2018 (Jemena, 2017), will allow gas to be supplied from northern Australian basins to the east coast. However, the pipeline has limited capacity (90 TJ/day), and large distances will mean high transport costs.

Most of the priority basins contain gas pipelines, with five of the basins containing processing and storage facilities (Table 5-7). However, a key issue is the distance from pipelines to potentially prospective areas. Some basins will require only minor additional infrastructure. Other basins, especially those located in northern Australia, would require construction of significant additional infrastructure to bring gas to market. Development of plays in the McArthur Basin, southern Georgina Basin and Isa Superbasin, would all require construction of additional pipelines.

The ranking applied to basins regarding access to infrastructure is qualitative and is based on the level of knowledge and available data for the given basin. Ranking categories are:

- **Minor:** Only minor additional infrastructure required, depending on development location. Well serviced and moderately to well developed.
- **Moderate:** Moderate additional pipeline infrastructure required if development occurs away from existing developments. Variable levels of service and development.
- **Major:** Major additional infrastructure required to connect existing pipelines to most prospective areas for shale/ tight gas. Only poorly to moderately serviced or undeveloped.

Figure 5-7 provides a visual summary of the relative shale and/or tight gas prospectivity of the basins compared with access to infrastructure. From this assessment:

- The Cooper, Bowen, Otway and Gippsland basins all have significant existing infrastructure in place connecting them with the East Coast Gas Market, including pipelines and gas processing facilities. All regionals are well serviced in terms of road and rail, with proximity to at least moderately well-developed townships.
- The Amadeus and McArthur basins contains existing pipeline infrastructure, but development of any unconventional plays away from the producing fields would require significant further investment. Both basins are also located much further from the East Coast Gas Market.
- Development of shale and/or tight gas plays in the Clarence-Moreton Basin would require additional infrastructure development as the prospective area is over 100 km from the existing East Coast Gas Market pipeline network.
- Development of shale and/or tight gas plays in the Georgina Basin and Isa Superbasin would require major additional infrastructure development. There are currently no gas processing facilities and the prospective areas lie over 200 km from existing pipeline infrastructure. In addition, both areas are only poorly to moderately well serviced by road and rail, and are sparsely populated with few townships.

These rankings are intended as a guide to compare the access to market infrastructure at a whole of basin scale and should not be applied to any individual play. To determine additional infrastructure at play, lead or prospect level, significant additional analysis would be required.

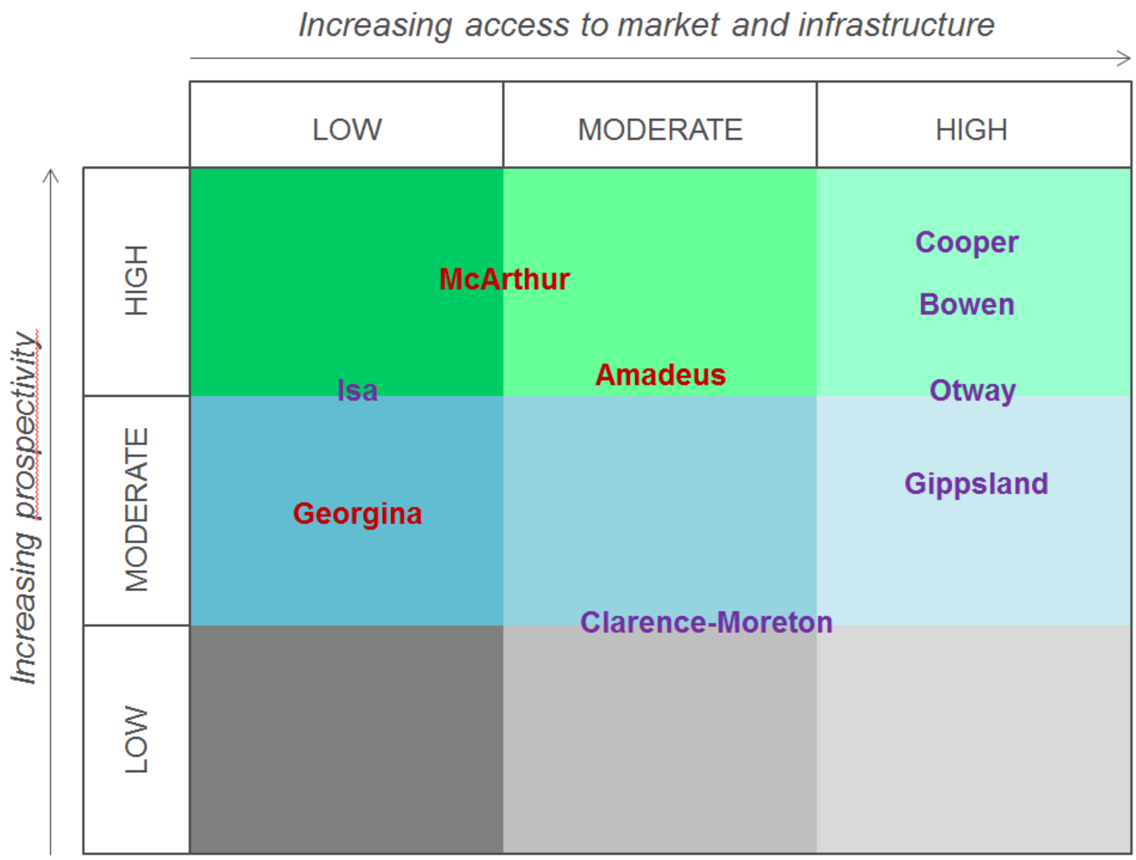


Figure 5-7: Shale/ tight gas prospectivity-infrastructure matrix for shortlisted basins. Red: basin located closer to the Northern Territory Gas Market. Purple: basin in proximity to the East Coast Gas Market.

Table 5-7 Summary of market access and infrastructure.

Basin	Gas market	Pipeline	Pipeline to prospective area (km)	Gas processing plants	Road and rail access	Townships	Additional infrastructure requirements
Amadeus Basin	Northern Territory	Amadeus Gas (Amadeus Basin to Darwin); Palm Valley to Alice Springs Pipeline	0–200	Mereenie; Palm Valley	Poorly to moderately well serviced	Limited development	Moderate
Bowen Basin	East Coast	Southwest Queensland Pipeline; Queensland Gas Pipeline; Roma to Brisbane Pipeline	<100	Rolleston; Central; Wallumbilla; Kincora; Silver Springs	Well serviced	Developed	Minor
Clarence-Moreton Basin	East Coast	Roma to Brisbane Pipeline	100–200	None	Well serviced	Well developed	Moderate-minor
Cooper Basin	East Coast	Moomba to Adelaide Pipeline; Moomba to Sydney Pipeline; Carpentaria Pipeline	<100	Moomba; Ballera	Moderately well serviced	Limited development	Minor
Georgina Basin	Northern Territory	Amadeus Gas Pipeline (Amadeus Basin to Darwin); Northern Gas Pipeline (under construction)	>200	None	Poorly to moderately well serviced	Undeveloped	Major
Gippsland Basin	East Coast	Victorian Transmission System (GasNet); South Gippsland Pipeline; Tasmania Gas Pipeline	<100	Longford; Long Island; Patricia/Baleen	Well serviced	Well developed	Minor
Isa Superbasin	Northern Territory	Carpentaria Pipeline	>200km	None	Poorly serviced	Undeveloped	Major
McArthur Basin	Northern Territory	Daly Waters to McArthur River Pipeline; Amadeus Gas Pipeline	0–200km	None	Poorly to moderately well serviced	Undeveloped	Moderate–major
Otway Basin	East Coast	SEA Gas Pipeline (Port Campbell to Adelaide)	<100	Katnook; Otway; Heytesbury; Iona; Minerva	Well serviced	Well developed	Minor

5.3.1.4 Prioritisation based on regulatory environment

Policy decisions made by governments and regulators affect the level and diversity of supply in the East Coast Gas Market. All Australian states and territories have stringent regulatory frameworks in place to manage impacts of petroleum exploration and production.

There are moratoria and other regulatory restrictions in New South Wales, Victoria and Tasmania preventing or impeding onshore gas exploration and development. In the Northern Territory, a moratorium is in place while consideration is being given to the recommendations on an inquiry into hydraulic fracturing. Only South Australia and Queensland have no current restrictions for exploration and development. Details of these differing regulatory environments by state and territory discussed in the basin audits and are summarised below in Table 5-8.

Table 5-8 Summary of moratoria and other regulatory restrictions preventing or impeding onshore shale and/or gas exploration and development by states connected to the East Coast and Northern Territory gas markets.

State/Territory	Moratoria and other regulatory restrictions	Timeframe	Key source
NT	Temporary moratorium on hydraulic fracturing lifted for 51% of the NT in April 2018	April 2018	Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (2018)
NSW	Restrictions of hydraulic fracturing activity	On-going	NSW Government (2012a, b)
QLD	No restrictions		
SA	10 Year Moratorium on hydraulic fracturing in south-east SA	Until 2028	DPCSA (2017b)
TAS	Moratorium on hydraulic fracturing	Until 2020	Tasmanian Government (2015)
VIC	Permanent ban on hydraulic fracturing	On-going	Victorian Legislative Council: Environment and Planning Committee (2015); Victorian Government (2017)

5.3.2 Groundwater, surface water, environmental and social considerations

The purpose of this section is to present a brief summary of the groundwater, surface water, environmental and social considerations to assist in the basin selection for assessment in Stage 2. It is not to rank the basins, which would require subjective values to be placed on items (National parks, for example) that have a diverse range of values attached to them across the community.

5.3.2.1 National-scale data summary

Table 5-9 presents the summary of the national-scale groundwater, surface water, environmental and social considerations as described in Section 5.2.4 and the following syntheses are provided:

- All basins assessed contain, to greater or lesser degrees, aquifers capable of supplying varied quality of groundwater, with principal aquifer productivity ranging from low-moderate (Clarence-Moreton Basin) to highly productive (most other basins). Local and regional variations to this will exist and will require further investigations at later stages of basin analysis.

- All basins contained groundwater dependant ecosystems. The Otway and Amadeus basins have the smallest area (1,500 km^2 and 1,600km^2 respectively), the Mount Isa Province and Bowen Basin have the greatest (38,000 km^2 and 26,000km^2 respectively). Wetlands were also present in all basins, ranging from 50 km^2 in the Amadeus Basin to 16,200 km^2 in the Cooper Basin.
- Protected areas (such as national parks and reserves) and land subject to Native Title and Indigenous Protected Areas were present in all basins; however the area covered varied considerably. Protected Areas were largest in the McArthur and Cooper basins (19,600 km^2 and 15,400 km^2 respectively) and lowest in the Gippsland and Clarence-Moreton basins (1,200 km^2 and 3,600 km^2 respectively). With regards to Native Title and Indigenous Protected Areas, the Otway and Clarence-Moreton basins have the least (1,400 km^2 and 2,000 km^2 respectively), whilst the McArthur Basin and Mount Isa Province have the greatest area (135,800 km^2 and 116,400 km^2 respectively).
- Population within basins is highly variable. The lowest population was the Cooper Basin (population 400) and the highest was the Clarence-Moreton Basin (population 1,000,400). The number of registered groundwater bores in each basin is generally related to population, with the top three most populous basins also showing the greatest number of registered bores.
- The predominant land use for all basins was grazing (either native vegetation or modified pastures). The exception is the Amadeus Basin, where Protected Areas are the largest single land use.

Table 5-9 Summary table of the key characteristics on groundwater and surface water resources, and environmental and social factors. Further details are found in the relevant section of Appendix C for each basin.

Basin	Hydrogeology and surface water				Environmental			Social		
(Refer to basin audit in Appendix C)	No. Bores/ Density (bores/km^2)	Bore Depth m (mean)	Principal Aquifer Productivity (1)	Groundwater Salinity range (TDS mg/L)(2)	GDE (area km^2)*	Protected Areas (area km^2)*	Wetlands (area km^2)*	Population*	Native Title / Indigenous Protected areas (area km^2)*	Land Use Top 3 (by area)
Amadeus Basin	3,712 (0.02)	83	Variable: Low to Highly Productive	500–4,000	1,600	5,100	50	8,200	53,800	1. Protected areas 2. Grazing native vegetation 3. Nature conservation
Bowen Basin	14,769 (0.10)	148	Highly Productive (south) Low-moderate Productivity (north)	500–2,000+	26,000	6,000	700	80,900	11,100	1. Grazing native vegetation 2. Dryland cropping 3. Production forestry
Clarence-Moreton Basin	36,480 (0.95)	49	Low-Moderate Productivity	40–24,300	2,700	3,600	300	1,000,400	2,000	1. Grazing native vegetation 2. Grazing modified pastures 3. Dryland cropping
Cooper Basin	4,066 (0.03)	1,505	Highly Productive	900–18,000	13,800	15,400	16,200	400	61,600	1. Grazing native vegetation 2. Nature conservation 3. Mining and waste
Georgina Basin	5,797 (0.02)	91	Highly Productive	390–5,000+	7,700	9,700	6,500	3,700	188,200	1. Grazing native vegetation 2. Other Protected areas 3. Minimal use
Gippsland Basin (Onshore)	32,564 (2.82)	75	Highly Productive	200–13,000	1,800	1,200	1,600	396,200	2,100	1. Grazing modified pastures 2. Plantation forestry 3. Nature Conservation
McArthur Basin	4,700 (0.02)	63	Highly Productive (south); Low-moderate Productivity (north)	50–105,000	8,900	19,600	5,400	29,800	135,800	1. Grazing native vegetation 2. Other Protected areas 3. Nature conservation
Mount Isa Province, including the Isa Superbasin	6,009 (0.02)	158	Variable: Low – Highly Productive	390–5,000+	38,000	10,000	6,300	25,000	116,400	1. Grazing native vegetation 2. Other Protected areas 3. Nature Conservation
Otway Basin (Onshore)	51,458 (1.94)	43	Highly Productive	500–200,000	1,500	3,900	500	358,400	1,400	1. Grazing modified pastures 2. Plantation forestry 3. Nature conservation

(1) Based on the principal aquifer productivity classification as per Jacobson, G, and Lau JE, (1987), *"Hydrogeology of Australia"*. Where clear spatial trends are present, or an approximately even division of classification exists, a range is given. Highly productive – extensive aquifer distribution with most bore yields greater than 5 L/s; Low-moderate productivity – extensive aquifer distribution with most bore yields of 0.5–5 L/s; Low – local aquifer distribution, bore yields less than 0.5 L/s.

(2) Groundwater salinity level reflects a generalised level within basin, based on data presented in Appendix C. Higher and lower values are expected to be encountered within the basin.

* Rounded to nearest 100 (values >1,000) otherwise rounded to nearest 10.

5.3.2.2 Basin summary: groundwater, surface water, environmental and social considerations

This section presents a summary of the basin groundwater, surface water, environmental and social factors results of the basin audit, whilst further details are presented in Appendix C.

5.3.2.2.1 Amadeus Basin

The Amadeus Basin is characterised by aquifers of variable productivity, ranging from low to highly productive with over 3,700 registered groundwater bores. The main aquifers are the Mereenie, Pacoota, and Hermannsburg sandstones, Jay Creek Limestone/Shannon Formation and Goyder Formation, and the alluvial and aeolian Cenozoic sediments. Groundwater flow is generally from the edge of the basin towards the centre and from west to east (Lau and Jacobson, 1991).

The largest groundwater user in the Amadeus Basin is the Roe Creek borefield, which supplies Alice Springs. Production of groundwater is primarily from the Mereenie Sandstone although 20% of total water supply is also sourced from the Pacoota, Shannon and Goyder aquifer (Power and Water Corporation, 2016; NT DLRM, 2016; English et al., 2012; Lloyd and Jacobson, 1987).

Because of low rainfall, recharge rates are lower than current extraction rates and so groundwater levels in the Roe Creek borefield are currently declining by about one metre every year. However, there are still sufficient groundwater reserves available in the eastern Amadeus Basin to maintain water supplies to Alice Springs for hundreds of years (Power and Water Corporation, 2016; NT DLRM, 2016).

Groundwater quality in the eastern Amadeus Basin is relatively fresh (500–1,000 mg/L TDS) near the Roe Creek borefield with higher saline groundwater >4,000 mg/L at depth and to the south and west (Macqueen and Knott, 1982).

Surface water flows across the Amadeus Basin are ephemeral. The major drainage systems in the Amadeus Basin are the Hugh, Finke and Todd rivers, which contain no surface storages (BoM, 2014; NT DLRM, 2016). Surface water information is limited to river height, primarily on the Todd River and its tributaries with no surface water quality information monitored. The basin supports an estimated 1,600 km^2 of groundwater dependant ecosystems.

The Amadeus Basin contains 5,100 km^2 of protected areas, including national parks and 50 km^2 of wetlands of national importance – the largest nationally important wetland by area is the Karinga Creek Palaeodrainage System. National Parks include Finke Gorge, Watarrka, Tjoritja / West MacDonnell, and Uluru–Kata Tjuta. Most of the region is sparsely populated (basin population 8,200), with significant Aboriginal Protected Areas and areas of Native Title (53,000 km^2 in total); apart from protected areas, the majority of land is used for native vegetation grazing.

See Appendix C.1 for more details and references on the Amadeus Basin.

5.3.2.2.2 Bowen Basin

The Bowen Basin is characterised by aquifers of variable productivity, ranging from low–moderate productivity in the north, to highly productive in the south and contains over 14,700 registered groundwater bores. The northern half of the Bowen Basin geology is either exposed or covered by a thin veneer of Cenozoic aged units. In contrast, the southern portion of the basin is covered by the Surat Basin, which is in turn overlain, to varying degrees, by Cenozoic alluvial and volcanic cover units.

The dominant groundwater resource in the south occurs within aquifers of the Surat Basin, which constitutes part of the Great Artesian Basin. In the north, the Triassic Clematis Group sandstones and Permian coals contain deep aquifers that tend to be exploited where shallower options are not available. Recharge occurs where aquifers outcrop, with flow towards the deeper basin centres. Most groundwater is poor in quality, suited only for stock and some domestic purposes. Groundwater salinity increases from recharge areas (occasionally 250 mg/L or less) towards the south and west to over 2,000 mg/L (Radke et al., 2000).

Groundwater is managed under Queensland legislation, with water plans for the Great Artesian Basin covering the southern portion of the basin; however many Bowen Basin groundwater bores are unmetered, so extraction rates are difficult to estimate.

The main river systems over the northern Bowen Basin are tributaries to the Fitzroy River, such as the Nogoa, Comet, Dawson, and Brown rivers. To the south the Condamine–Balonne river system drains into the Murray-Darling Basin, and has extensive floodplains and alluvial aquifers. Salinity is variable in the Fitzroy River, with the lowest values occurring in the headwaters; the upper Condamine River is fresh to brackish. Streamflow increases down catchment in both systems with seasonal and annual variation and there are many surface water storages. The basin supports a range of groundwater dependant ecosystems covering an estimated area of 26,000 km^2.

Within the Bowen Basin there are approximately 6,000 km^2 of protected areas, including over twenty national parks, as well as 600 km^2 of wetlands of national importance. Population density is variable across the district (total population 80,900) and is concentrated around significant population centres such as Emerald and Roma. Stock grazing on native vegetation, dryland cropping and production forestry are the dominant types of land use. A total of 11,100 km^2 of land is covered by native title or indigenous protected area.

See Appendix C.2 for more details and references on the Bowen Basin.

5.3.2.2.3 Clarence-Moreton Basin

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 (Rassam et al., 2014) and Maranoa Balonne Condamine Bioregional Assessments (Welsh et al., 2014). The following summary draws heavily on the work completed as part of these assessments.

The Clarence-Moreton Basin is characterised by aquifers of generally low-moderate productivity, and it contains over 36,400 registered groundwater bores (BoM, 2016). The main groundwater systems are Mesozoic aquifers within the Clarence-Moreton Basin, and aquifers in various Cenozoic alluvial systems (e.g. Condamine Alluvium) and volcanic units (e.g. Main Range Volcanics).

Highly variable groundwater salinity values are found in alluvial aquifers (40–18,000 mg/L), and deeper Triassic–Jurassic aquifers in the Walloon Coal Measures, Koukandowie Formation, Gatton Sandstone and the Woogaroo Subgroup (300–24,300 mg/L); in contrast with the less variable salinity in the Main Range Volcanics (200–1,900 mg/L) and the upper Jurassic Grafton and Orara formations (360–2,300 mg/L) (OGIA, 2016; Rassam et al., 2014). With the exception of pumping and irrigation stresses, alluvial groundwater flow is topographically driven; while sedimentary rock groundwater flow directions are not well understood, they are presumed to exhibit north-easterly flow.

The majority of aquifers are managed under Water Sharing Plans and/or Water Resource Plans, with estimated sustainable diversion limits and licensed entitlements provided aquifer by aquifer.

The Clarence-Moreton Basin is overlain by several river catchments draining east to the Pacific Ocean near the Queensland–New South Wales border, and the westward flowing Condamine–Culgoa River system draining into the Murray-Darling Basin. The Condamine–Culgoa, Richmond, Logan-Albert and Brisbane River systems have licensed water harvesting. Several active and discontinued river gauges provide streamflow and electrical conductivity measurements. The basin supports approximately 2,700 km^2 of groundwater dependant ecosystems.

The Clarence-Moreton Basin contains 3,600 km^2 of protected areas, including numerous national parks and 300 km^2 of wetlands of national importance and the Ramsar-listed Moreton Bay wetland. Dense human population clusters occur in this area overlapping parts of South-east Queensland (which intersects parts of Brisbane-Ipswich and Toowoomba) and north-eastern New South Wales (e.g. Lismore and Grafton). Total population for the basin exceeds 1,000,000 and is the most populous basin under consideration. Stock grazing on native and modified land and dryland cropping are the dominant types of land use. A total of 2,000 km^2 of land is covered by native title or indigenous protected area.

See Appendix C.3 for more details and references on the Clarence-Moreton Basin.

5.3.2.2.4 **Cooper Basin**

As part of the Bioregional Assessment Program into coal mining and CSG 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.

Groundwater systems occur within the Cooper Basin, along with the overlying Eromanga Basin and Lake Eyre Basin. Groundwater is predominantly extracted from aquifers in the overlying Eromanga Basin sequence (part of the Great Artesian Basin), and to a lesser extent, Lake Eyre Basin aquifers. A limited amount of co-produced groundwater is extracted from petroleum and gas wells within the Cooper Basin sequence.

Aquifers in the Eromanga Basin sequence are generally classified as highly productive (Jacobson and Lau, 1987; Table 5-9). The confined aquifers of the Eromanga Basin sequence are intersected by numerous artesian and sub-artesian bores. Water produced from these bores has salinity levels suitable for stock, domestic and town uses. There are over 4,000 registered groundwater bores in the Cooper Basin footprint.

Salinity values within aquifers of the Eromanga Basin dictate the types of use. Winton–Mackunda aquifers are used for stock water, while Coorikiana Sandstone has higher salinities and poor yields and is therefore not widely used for groundwater extraction. Groundwater salinity in the Eromanga Basin is typically less than 6,000 mg/L (usually ~ 3,000 mg/L), while underlying Cooper Basin units are more saline, and reaching up to 18,000 mg/L (Smith et al., 2015).

Queensland legislation requires licenses for both artesian and connected sub-artesian bores extracting water from the Great Artesian Basin, while South Australia has a Water Allocation Plan that limits drawdown in the vicinity of springs (such as those found in this western Eromanga Basin area). South Australia also provides a total groundwater extraction allocation to the petroleum industry of 60 ML/day (Smith et al., 2015).

Overlying the Cooper Basin are areas within the Cooper Creek–Bulloo River and Diamantina–Georgina Rivers catchments. In these arid areas rivers are ephemeral and anastomosing, and floodplains are wide (in excess of 60 km) Streamflow is highly variable between years and highly seasonal. Since there are no perennial watercourses, major dams and storages, there is negligible use of surface water.

Surface water salinity in the Cooper Creek is generally low (EC usually less than 200 µS/cm), but turbidity can be high at times of mid flow (Cockayne et al., 2013; Smith et al., 2015). The Queensland Government has reserved 2,000 ML of unallocated water in the Cooper Creek catchment; while the Georgina and Diamantina Water Resource Plan 2004 provides a general reserve for the lower Diamantina of 1,000 ML as well as an allocation across the entire catchment 1,500 ML for projects of state significance. The basin supports approximately 13,800 km^2 of groundwater dependant ecosystems.

Within the Cooper Basin there are 15,400 km^2 of protected areas, including national parks and 16,200 km^2 of wetlands of national importance. One significant site is the Coongie Lakes, which are wetlands of international significance and listed by the Ramsar Convention. The region is very sparsely populated (total basin population 400), with almost half the area coinciding with Native Title areas (61,600km^2). The main land use is for stock grazing on native vegetation.

See Appendix C.4 for more details and references on the Cooper Basin.

5.3.2.2.5 Georgina Basin

The primary groundwater bearing units identified in the Georgina Basin are the widespread, highly productive Paleozoic succession of carbonate formations (e.g. Gum Ridge and Anthony Lagoon formations). Less significant groundwater resources are found in fractured rock (e.g. Beetle Creek Formation) and porous rock (e.g. Steamboat Sandstone) aquifers. Sporadic occurrences of Cenozoic age sediments provide regionally significant groundwater resources. Towards the centre of the basin major aquifer units are typically intersected between 100–200 m below ground level, while towards the basin margin they are at shallower depths. The basin has over 5,700 registered groundwater bores. The southeastern portion of the basin area contains aquifers within the overlying Eromanga Basin sequence, which forms part of the Great Artesian Basin.

Groundwater salinity levels are generally low in the Middle Cambrian Limestones and are generally lower than the non-carbonate aquifers, ranging from around from 390 mg/L to over 900 mg/L Total Dissolved Solids (TDS) Rare areas of high salinity exceeding 5,000 mg/L TDS exist in former evaporite beds. Cenozoic aquifers of the Ti-Tree and Western Davenport region typically show groundwater of sufficient quality for irrigation and stock purposes. Groundwater salinity in the major aquifers of the Great Artesian Basin in this region range between 500–1,200 mg/L TDS (Ransley et al., 2015).

Within the Georgina Basin groundwater is generally the main water resource for consumptive use including: mining, irrigation and stock and domestic.

Several river catchments overlie the Georgina Basin, with most draining north towards the Gulf of Carpentaria, while parts of the Diamantina-Georgina (south to Lake Eyre) and Victoria–Wiso (northwest to Tanami–Timor Sea coast) are also observed. Most of these are ephemeral, with strongly seasonal flow. There are two exceptions: the perennial Gregory and O’Shannassy rivers. There is negligible use of surface water in the region, as groundwater is much more dependable. Losing reaches of ephemeral streams recharge the underlying aquifers, while discharge springs and associated groundwater-dependent ecosystems (7,700 km^2) has been mapped.

Within the Georgina Basin there are 9,700 km^2 of protected areas, including national parks (Limmen, Boodjamulla (Lawn Hill), Lytwelepenty /Davenport Ranges, Dulcie Range, and Camooweal Caves National Parks) and 6,500 km^2 of wetlands of national importance. The region is sparsely populated (basin population 3,700), but has about half the area coinciding with Native Title areas (188,200km^2); the main land use is for grazing stock on native vegetation.

See Appendix C.5 for more details and references on the onshore Georgina Basin.

5.3.2.2.6 Gippsland Basin

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, 2015a) 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 section.

The Cretaceous–Cenozoic Gippsland Basin is contains several stratigraphic packages, which correspond to distinct aquifer systems: the upper system of Sale Group sediments, the middle system of the Latrobe Valley and Seaspray groups, the lower system of the Latrobe Group, and the deep Strzelecki Group. Each of the first three systems consist of various aquifer and aquitard units, the aquifers being classed as highly productive, while the deep Strzelecki Group has low permeability and is generally considered as hydraulic basement along with Palaeozoic basement rocks. The basin contains over 32,500 registered groundwater bores.

Low salinity groundwater is found in the upper aquifers onshore (some less than 500 mg/L TDS), with salinity increasing towards the east and in some deeper units. Higher salinity groundwater (3,500 – 13,000 mg/L TDS) are evident in the bedrock aquifer (Yates et al., 2015).

Several Groundwater Management Units have plans and entitlements established. Groundwater is used for irrigation, urban supplies, stock and domestic, industrial purposes, cooling power stations, and supporting 1,800 km^2 of identified groundwater-dependent ecosystems.

The majority of the Gippsland Basin is overlain by rivers in the Mitchell–Thomson and South Gippsland regions, with small parts of the Snowy River and East Gippsland river regions. River water tends to be fresh, with the exception of relatively more saline and turbid rivers of South Gippsland river region. The majority of surface waters are less than 500 µS/cm EC and 10 Nephelometric Turbidity Units (Yates et al., 2015). Streamflow is measured at some 13 monitoring stations.

Surface water is used for irrigation (e.g. Macalister Irrigation District) as well as stock and domestic, urban, commercial and power generation purposes. Rivers tend to be gaining, with a strong hydraulic connection; however in high-flow periods, excess surface water recharges groundwater systems.

Within the Gippsland Basin there are 1,200km^2 of protected areas, including national parks, and also 1,600 km^2 of wetlands of national importance, including three Ramsar Wetlands at Gippsland Lakes, Western Port and Corner Inlet. There are significant population centres stretching from the edge of Melbourne with the Mornington Peninsula in the west, the Latrobe Valley in the centre, and Sale in the east (total basin population over 395,000 people). Most land is used for various types of production from dryland agriculture and plantation forestry.

See Appendix C.6 for more details and references on the Gippsland Basin.

5.3.2.2.7 McArthur Basin

Groundwater within the McArthur Basin itself is often in minor, localised, fractured aquifers; however the Dook Creek Formation dolostone acts in part as a regional aquifer. The main groundwater resources are found in overlying basins, specifically limestones (e.g. Gum Ridge and Anthony Lagoon formations) of Cambrian basins (Georgina–Wiso–Daly basins) and sandstones of Cretaceous basins (Carpentaria and Money Shoal basins) that overlie portions of the McArthur Basin.

Most regional aquifers contain good quality water, although dissolving limestones accumulates calcium and other solutes; whereas the Roper Group sandstones (Beetaloo Sub-basin of McArthur Basin) are often hypersaline. The basin has over 4,700 registered groundwater bores.

Regional groundwater flow occurs only in the major aquifers, which tend to slowly transmit water long distances towards discharge features, particularly the perennial Roper and Daly Rivers. Recharge is often indirect, and is greater where Cretaceous cover is limited. The combination of high wet-season recharge and low existing groundwater development results in full recovery of groundwater levels annually. Vertical connectivity is not well understood. Discharge is via evapotranspiration and spring/river baseflow. Groundwater is used for regional community water supply, stock and domestic use and mining projects. Groundwater supports an estimated 8900 km^2 of groundwater dependant ecosystems in the basin.

Overlying the McArthur Basin are multiple river catchments, draining east to the western Carpentaria Coast and to the north to the Arafura and Timor seas. The Roper River is a major perennial river, while a number of coastal rivers have perennial segments. These perennial reaches align with underlying regional aquifers (Dook Creek Formation dolostones, Cambrian limestones, and Cretaceous sandstones) which provide baseflow. Where supporting aquifers are absent, the rivers become losing streams, which combined with the high evapotranspiration leads to reduced flows downstream.

Limestone aquifers tend to provide high EC baseflow to the Roper River, which increases with evapotranspiration. Wet season storm events produce less saline but more turbid water with the substantially higher streamflow. About 96% of rainfall and 91% of runoff occurs in the wet season – this allows ephemeral streams to flow, and raises the stage on perennial rivers. During the dry season, ephemeral streams form a series of disconnected pools.

Within the McArthur Basin there are 5,400 km^2 of wetlands associated with the groundwater discharge and coastal locations. There are also 19,600 km^2 of protected areas such as national parks, conservation reserves and nature reserves. In the north-western corner of the McArthur Basin are parts of the Kakadu National Park and its associated Ramsar-listed wetlands of international significance and world heritage sites. The region is sparsely populated (basin population 29,800), and has almost half the area coinciding with either Native Title areas or Aboriginal Protected Areas, such as parts of Arnhem Land; outside protected areas. The main land use is for stock grazing on native vegetation.

See Appendix C.7 for more details and references on the McArthur Basin.

5.3.2.2.8 Mount Isa Province, including the Isa Superbasin

As the Isa Superbasin spatial extent remains poorly defined, with no formal outline included in Geoscience Australia's Geological Provinces Database (Stewart et al., 2013), the groundwater summary of the Isa Superbasin was evaluated in the context of the broader Mount Isa Province. The groundwater system across the province can be categorised into three broad hydrogeological zones, east, west and central zones. In the east, the overlying Jurassic–Cretaceous aquifers of the Great Artesian Basin in the Carpentaria and Eromanga basins represent a significant source of groundwater. The western margin of the Mount Isa Province is overlain by the Georgina Basin, where Cambrian limestones (e.g. Gum Ridge and Anthony Lagoon formations) are typically classified extensive and highly productive aquifers. The central area, including the Precambrian Mount Isa Inlier, lacks these overlying aquifers, so is described as a region of local aquifers of generally low productivity.

Groundwater quality is variable across the zones, however typically acceptable for livestock, irrigation and domestic supply. A salinity range of 500–1,200 mg/L TDS in the major Great Artesian Basin aquifers and Georgina Basin aquifers is recorded, with some regions of significantly higher concentrations such as in former evaporite beds. Little groundwater development has occurred in the western (Northern Territory) side, while some development in the central region has been noted. An estimated 37,700 km^2 of groundwater dependant ecosystems are present in the basin.

Major surface water systems include the Diamantina–Georgina Rivers, Nicholson–Leichhardt Rivers and the Flinders–Norman Rivers. Generally streamflow in the Mount Isa Province is seasonal and depends on monsoonal rains. A number of significant population centres, however, rely on surface water for domestic and industrial supply. These include Mount Isa sourcing water from Lake Moondarra and Lake Julius, and Cloncurry sourcing water from Chinaman Weir on the Cloncurry River. The Gregory and Victoria Rivers contain fresh water, while fresh to marginal water is found in the Roper River and Gunpowder Creek. Springs of the Great Artesian Basin occur as groundwater discharge features and have associated groundwater-dependent ecosystems.

Within the Mount Isa Province there are over 10,000 km^2 of protected areas, including national parks (Diamantina, Boodjamulla (Lawn Hill), Astrebla Downs, and Camooweal Caves National Parks) and also 6,300 km^2 of wetlands of national importance. Outside major population centres such as Mount Isa and Cloncurry, the region is sparsely populated (basin population 25,000). Large areas of Native Title or indigenous protected areas are present (116,400 km^2) occur, while the main land use is for stock grazing on native vegetation.

See Appendix C.8 for more details and references on the Isa Superbasin and Mount Isa Province.

5.3.2.2.9 Otway Basin

A number of studies (Bush, 2009; Clark et al., 2015; DELWP and GSV, 2015b) have detailed the geology and hydrogeology of the Otway Basin. This section synthesises the existing knowledge of the hydrogeology of the Otway Basin.

The main aquifers of the Otway Basin are: Oligocene–Miocene limestones (e.g. Gambier Limestone and Port Campbell Limestone) which behave as an unconfined aquifer; and a lower Paleocene–Eocene sandy aquifer system (e.g. Dilwyn Formation and Mepunga Formation). Other Cenozoic aquifers are typically local or intermediate-flow systems, including fractured and weathered basalts of the Newer Volcanics Province. Underlying these are Mesozoic sedimentary rock aquifers, such as the Sherbrook Group and Otway Group. Aquifers are classified as generally highly productive and the basin has over 51,000 registered groundwater bores (BoM, 2016).

Groundwater flow is mostly based on topography, with a south- or southwesterly flow direction. Salinity in the upper limestones is mostly less than 1,500 mg/L TDS, but can vary up to 7,000 mg/L TDS; in the Paleocene-Eocene sands, salinity increases from 500 mg/L TDS in recharge areas towards 5,600 mg/L TDS near the coast (Leonard, 2003).

There are 16 Groundwater Management Units in Victoria, along with one in South Australia. These are mostly less than 50% developed, but some central-eastern parts are up to 80% developed. The groundwater resource is used for irrigation, salinity control, stock and domestic, urban, and power generation purposes. It is estimated that there are approximately 1,500 km^2 of groundwater dependant ecosystems in the basin.

Surface water occurs in several river catchments flowing south into the sea. Water quality is quite variable. Streamflow is seasonal, with winter-spring high flow and summer-autumn low flow; however in examples such as the Barwon River, this flow is regulated to provide water to Geelong and other towns as well as farm supply. The entitlements from the Otway Coast, Barwon and Moorabool catchments are used for irrigation (79%), urban and commercial (15%), stock and domestic, and power generation purposes.

Groundwater–surface water interactions are variable along the rivers. They are generally losing in the upland reaches and gaining in the mid-reaches, and variable along the lower reaches.

Within the Otway Basin are over 3,900 km^2 of protected areas, including national parks and also 500 km^2 of wetlands of national importance, and five Ramsar Wetlands: Western District Lakes, Port Phillip Bay (Western Shoreline) and Bellarine Peninsula – Lake Connewarre, Bool and Hacks Lagoons, Piccaninnie Ponds Karst Wetlands, and Port Phillip Bay (Western Shoreline) and Bellarine Peninsula – Swan Bay. Various towns and cities occur between Geelong in the east and Mount Gambier in the west (total basin population 358,400) Land use is dominated by stock grazing modified pastures and dryland forestry.

See Appendix C.9 for more details and references on the onshore Otway Basin.

6 Summary

This report contains the results of Stage 1 of the Geological and Bioregional Assessments Program, the rapid regional basin prioritisation, designed and conducted by Geoscience Australia (GA) and managed by the Department of the Environment and Energy (DoEE). This report presents the context of the program and describes the evidence based decision making process used in Stage 1 to narrow the focus of the geological and bioregional resource assessments on which a final prioritisation can be undertaken by the DoEE and participating stakeholders.

6.1 Basin geology, prospectivity, market access and regulatory environment

Shortlist of high priority basins

Of the onshore basins situated near existing east-coast gas market pipelines, nine were identified in which active exploration for shale and/or tight gas resources is already underway and possible plays, 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 investment and no other impediment to development (e.g. regulatory restrictions; environmental or social concerns), these basins were considered to have potential development timeframes of ten years or less, and hence were shortlisted as priority areas for further early research, as part of the basin audit.

Shale and tight gas prospectivity and confidence

The results of the basin audit were used to assign a ‘shale and tight gas prospectivity’ ranking and a ‘confidence’ ranking to each basin. Both rankings are qualitative and were based on the level of knowledge and available data for the given basin. Key factors considered in assessing regional shale and tight gas prospectivity included overall petroleum prospectivity; estimated prospective resource area (km^2), where such information was available from existing public domain sources, prospective resources, and shale/ tight gas exploration success to date. The confidence rankings were based on both the amount of data available within the basin and the quality of that data and were assessed based on basin area, number of petroleum wells and shale/ tight gas wells drilled to date, line km of seismic data, overall exploration status and, shale/ tight gas exploration status. Less data of lower quality resulted in low confidence for the prospectivity ranking.

From this assessment:

- The Cooper Basin is ranked high in terms of both prospectivity and confidence, reflecting the extensive exploration for shale and tight gas resources already undertaken in this basin.
- The McArthur, Bowen and Amadeus basins' prospectivity ranks as high, based on the quality of known and potential source rocks, while confidence is only moderate reflecting the more limited exploration history in these basins.
- The onshore Otway Basin ranks as moderate–high prospectivity and high confidence due to data density and relative quality.
- The Isa Superbasin's prospectivity ranks as moderate–high due to the booked contingent resources, however confidence is low– moderate reflecting the sparse data distribution and very limited exploration history.
- The Gippsland Basin is ranked moderate for prospectivity based the relatively small area of potential unconventional gas resources which may be developed within a 10 year timeframe, however confidence is high due to data density and quality.
- The Georgina Basin is ranked as moderate in terms of prospectivity, reflecting the relatively poor results of recent exploration, with a low–moderate confidence reflecting sparse data distribution.
- The Clarence-Moreton Basin is ranked as low–moderate for both prospectivity and confidence, reflecting the relatively small prospective area, early stage of exploration and limited data.

These rankings could be improved with more data collection to increase the knowledge of the basin, and by conducting further studies as described in the basin recommendations list.

Proximity to market and access to infrastructure

In assessing proximity to the East Coast Gas Market, those basins already producing gas directly into this market were ranked highest. The Northern Gas Pipeline (NGP), linking the Northern Territory Gas Market to the East Coast Gas Market and scheduled to open by the end of 2018 (Jemena, 2017), will allow gas from northern Australian basins to be supplied to the East Coast Gas Market. However, the pipeline has limited capacity, and large distances will mean high transport costs.

The factors considered in assessing access to infrastructure were proximity to existing oil and gas pipelines, additional infrastructure requirements, gas processing and storage facilities, road and rail access and proximity to townships. A ranking applied to each basin regarding access to infrastructure is qualitative and was based on the level of knowledge and available data for the given basin.

From this assessment:

- The Cooper, Bowen, Otway and Gippsland basins all have significant existing infrastructure in place connecting them with the East Coast Gas Market, including pipelines and gas processing facilities. All regionals are well serviced in terms of road and rail, with proximity to at least moderately well-developed townships.
- The Amadeus and McArthur basins contain existing pipeline infrastructure and processing facilities, but development of any unconventional plays away from the producing fields would require significant further investment. Both basins are also located much further from the East Coast Gas Market.
- Development of shale and/or tight gas plays Clarence-Moreton Basin would require additional infrastructure development as the prospective area is over 100 km from the existing East Coast Gas Market pipeline network.
- Development of shale and/or tight gas plays in the Georgina Basin and Isa Superbasin would require major additional infrastructure development. There are currently no gas processing facilities and the prospective areas lie over 200 km from existing pipeline infrastructure. In addition, both areas are only poorly to moderately well serviced by road and rail, and are sparsely populated with few townships.

These rankings are intended as a guide to compare the access to market at a whole of basin scale and should not be applied to any individual play. To determine additional infrastructure at play, lead or prospect level, significant additional analysis would be required.

Regulatory Environment

Policy decisions made by governments and regulators affect the level and diversity of supply to the East Coast Gas Market. All Australian states and territories have strong regulatory frameworks in place to manage impacts of petroleum exploration and production.

There are moratoria and other regulatory restrictions in New South Wales, Victoria and Tasmania that prevent or impede onshore gas exploration and development. In April 2017 the Northern Territory Government lifted the moratorium on hydraulic fracturing over 51% of the Territory. The South Australian Government have placed a 10 year moratorium on hydraulic fracturing over the south-east of the state. Only Queensland has no current exploration and development restrictions. Western Australia does not contribute to the East Coast Gas Market and was therefore not considered.

Synthesis

Table 6-1 summarises the results of the rapid regional rapid prioritisation by theme for each shortlisted basin. Basins most likely to deliver new shale and/or tight gas resources to the East Coast Gas Market within five to ten years need to match the following criteria:

- high prospectivity for shale/ tight gas resources, which may be developed within a ten year timeframe;
- moderate to high confidence due to the level of data collected/ exploration status, and;
- located close to the East Coast Gas Market via existing infrastructure (including gas pipelines).

The Amadeus, Bowen, Cooper, Otway and McArthur basins, and Isa Superbasin, meet all of the above prioritisation criteria. The relatively small prospective area of the Gippsland and Clarence-Moreton basins, and the poor exploration successes in the Georgina Basin, mean these basins fail to meet the prospectivity criteria.

Regulatory constraints, such as exploration or hydraulic fracturing moratoria, may prevent or significantly impede onshore gas exploration and development. Of the top ranked prospectivity basins, the Cooper and Bowen basins remain unaffected by current restrictions; along with the majority of the prospective area of the Isa Superbasin (located in Queensland). In April 2018 the Northern Territory Government lifted the moratorium on hydraulic fracturing for 51% of the Northern Territory. The Otway basin is impacted by moratorium on hydraulic fracturing in the south-east of South Australia and the on-going ban on hydraulic fracturing in Victoria, which also impacts the Gippsland basin.

Table 6-1 Summary of rapid regional rapid prioritisation results for each shortlisted basin by the following themes: basin geology, shale/ tight gas resource prospectivity, gas market, additional infrastructure requirements and regulatory environment.

Basin	State	Shale/ tight gas prospectivity	Petroleum Data Confidence	Gas market	Additional infrastructure requirements	Regulatory environment
Amadeus	NT	Moderate–high	Moderate	Northern Territory	Moderate	Moratorium under consideration (NT)
Bowen	QLD	High	Moderate	East Coast	Minor	No moratorium (QLD)
Clarence-Moreton	NSW, QLD	Low–moderate	Low–moderate	East Coast	Moderate–minor	Restrictions (NSW)
Cooper	QLD, SA	High	High	East Coast	Minor	No moratorium (QLD, SA)
Georgina	NT, QLD	Moderate	Low–moderate	Northern Territory	Major	Moratoria under consideration (NT); No moratorium (QLD)
Gippsland	VIC	Moderate	High	East Coast	Minor	Ban (VIC)
Isa	NT, QLD	Moderate–high	Low–moderate	Northern Territory	Major	Moratoria under consideration (NT); No moratorium (QLD)
McArthur	NT	High	Moderate	Northern Territory	Moderate–major	Moratorium under consideration (NT)
Otway	SA, VIC	Moderate–high	High	East Coast	Minor	Ban (VIC); No moratorium (SA)

6.2 Groundwater, surface water, environmental and social considerations

Securing a water supply is a key consideration for shale and tight gas operations. It is typically met by groundwater and/or surface water resources in the vicinity of such operations. Whilst the national-scale data used in this report shows generally favourable aquifer productivity in most of the shortlisted basins assessed, local and regional variations will exist.

The basin audit assessment showed that the level of hydrogeological information – including groundwater systems understanding, groundwater quality, groundwater flow, and groundwater planning and use – varies widely between individual basins assessed and decreased with depth. The assessment showed that all basins, to greater or lesser degrees, have aquifers capable of supplying groundwater of varying quality. However, in some cases, these aquifers occur in overlying strata associated with younger sedimentary basins. For example, the southern portion of the Bowen Basin and the entire Cooper Basin is overlain by the Surat and Eromanga basins respectively, both of which contain important aquifers that constitute part of the Great Artesian Basin.

Principal aquifer productivity from national-scale data (Jacobson and Lau, 1987) ranges from low-moderate (Clarence-Moreton Basin) to highly productive aquifers in the Amadeus, Bowen, Cooper, Georgina, McArthur and Otway basins.

All basins had both GDEs and wetlands present. The basins with the least area of GDEs are the Otway and Amadeus Basins, with 1,500 km^2 and 1,600 km^2 respectively; while the Bowen and Cooper basins have the largest GDE area coverages at 26,000 km^2 and 13,800 km^2 respectively. The basins with the lowest area of wetlands are the Amadeus and Clarence-Moreton with 50 km^2 and 300 km^2 respectively; while large areas of the Cooper Basin (16,200 km^2), Mount Isa Province (6,300 km^2), which includes the Isa Superbasin, and the McArthur Basin (5,400 km^2) contain important wetlands. Groundwater dependant ecosystems and wetlands represent sensitive, often unique assets. Careful water management is required to protect GDEs from the impacts of any additional groundwater extraction.

Several basins assessed are subject to seasonal river flows, for example, the Amadeus and Cooper basins, where watercourses are ephemeral. Only a few perennial rivers occur in dry climate regions where regional aquifers provide baseflow. For example, within the McArthur Basin, the Roper River receives groundwater baseflow contribution from Cambrian limestone aquifers.

Protected areas (such as national parks and reserves) and land subject to Native Title and Indigenous Protected Areas are present in all basins to varying degrees. The Gippsland (1,200 km^2) and Clarence-Moreton (3,600 km^2) basins have the least area covered by Protected areas; Native Title and Indigenous Protected Areas were least prevalent in the Otway (1,400 km^2) and Clarence-Moreton (2,000 km^2) basins.

Human population varied widely between basins. The least populous basin, by a considerable margin, was the Cooper Basin (population 400) followed by the Georgina Basin (3,700); the highest was Clarence-Moreton Basin (population 1,000,400) which included the outskirts of Brisbane, while both the Gippsland and Otway basins (populations 396,200 and 358,400 respectively) contain large towns. The level of population gives an indication of the other water and land users in the region.

Despite some basins showing significant urban influence, the dominant land use for all basins is grazing (either native vegetation or modified pastures) with the exception of the Amadeus Basin where Protected Areas was the largest single land use. Other significant land uses include cropping (e.g. Bowen and Clarence-Moreton basins), forestry (e.g. Gippsland and Otway basins), and nature conservation (e.g. McArthur and Cooper basins).

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List of shortened forms

Table 6-2: List of shortened forms.

Short Form	Long Form
ABARES	Australian Bureau of Agricultural and Resource Economics and Sciences
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AERA	Australian Energy Resources Assessment
ASX	Australian Securities Exchange
BoM	Bureau of Meteorology
CAPAD	Collaborative Australia Protected Areas Database
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DELWP	Department of Environment, Land, Water and Planning
DIWA	Directory of Important Wetlands in Australia
DNRM	Department of Natural Resources and Mines (Queensland)
DNRME	Department of Natural Resources, Mines and Energy (Queensland)
DPCSA	Department of the Premier and Cabinet, South Australia
DREMP	Division of Resources and Energy, Minerals and Petroleum, New South Wales
DoEE	Department of the Environment and Energy
GA	Geoscience Australia
GAB	Great Artesian Basin
GDE(s)	groundwater-dependent ecosystem(s)
GIP	gas-in-place
GIS	geographic information system
GSNSW	Geological Survey New South Wales
GSV	Geological Survey of Victoria
LNG	liquefied natural gas
NHMRC	National Health and Medical Research Council
NNTT	National Native Title Tribunal
NRM region(s)	natural resource management region(s)
NRMMC	National Resource Management Ministerial Council
NTGS	Northern Territory Geological Survey
OGIA	Office of Groundwater Impact Assessment
PRMS	Petroleum Resource Management System

Energy measurement and conversion factors

The following text provides back ground information on energy measurements and conversion factors (from AERA, 2018).

Energy is the ability to do work. The International System of Units (SI) unit of energy across all energy types is the Joule (J). It is defined as the amount of work done by a force of one newton exerted over a distance of one metre.

Power is the rate at which work is delivered. The SI unit of power is the watt (W) One watt is equal to one joule per second (1 W = 1 J/sec) Watt is the common unit for electrical power (sometimes expressed as We) although may be used for thermal power (Wt).

Consumption of electric energy is measured in kilowatt-hours (kWh), which is equal to the power in kilowatts (kW) times the time period (hours (h)).

energy (kWh) = power (kW) x time (h)

The average annual energy production or consumption can be expressed in kilowatt-hours per year (kWh/year) For example, a power plant with a capacity of one MW produces 1000 kWh when the plant runs consistently for one hour. If the power plant runs consistently with no downtime for a year (8760 hours), the generator produces 8 760 000 kWh (8 760 MWh) in a year.

Both Joules and Watts are more commonly recorded in multiples.

EJ	Exajoule - 10^{18} joules
GJ	Gigajoule - 10^{9} joules
Gt	Gigatonne - 10^{9} tonnes
GW	Gigawatt - 10^{9} watts
kt	Kilotonne - thousand (10^{3}) tonnes
kW	Kilowatt - thousand (10^{3}) watts
kWh	Kilowatt-hours - thousand (10^{3}) watt-hours
ML	Megalitre - million (10^{6}) litres
mmbbl	Million (10^{6}) barrels
Mt	Million (10^{6}) tonnes
MW	Megawatts - 10^{6} watts
MWh	Megawatt-hours - 10^{6} watt-hours
PJ	Petajoules - 10^{15} joules
Tcf	Trillion (10^{12}) cubic feet
TJ	Terajoules - 10^{12} joules
TWh	Terawatt-hours - 10^{12} watt-hours

Decimal numbering system

Multiples of energy measurements in Australia are expressed in standard international decimal classification terms:

Multiple	Scientific exp.	Term	Abbreviation
Thousand	10^3	Kilo	k
Million	10^6	Mega	M
Billion	10^9	Giga	G
Trillion	10^{12}	Tera	T
Quadrillion	10^{15}	Peta	P
Quintillion	10^{18}	Exa	E

Energy measurement

Energy production and consumption are typically reported in the SI unit as petajoules (PJ) as used here but in some cases are reported in barrels of oil equivalent (BOE) and million tonnes of oil equivalent (MTOE).

Individual energy resources are commonly reported according to prevailing industry conventions. Petroleum is reported by volume and weight according to either the SI or the United States system as used by the American Petroleum Institute.

Energy resource	Measure	Abbreviation
Oil and condensate	Production, reserves: Litres (usually millions or billions)or barrels (usually thousands or millions) Refinery throughput/capacity: Litres (usually thousands or millions) or barrels per day (usually thousands or millions)	L, ML, GL bbl, kbbl, mmbbl ML, GL per day bd, kbd, mmbd
Natural gas	Cubic feet (usually billions or trillions)Or cubic metres (usually millions or billions of cubic metres)	Bcf, Tcf m^3, mcm, bcm
LNG	Tonnes (usually millions) Production rate: Million tonnes per year	t, Mt Mtpa
LPG	Litres (usually megalitres) or barrels (usually millions)	L, ML bbl, mmbl
Coal	Tonnes (usually millions or billions) Production rate: tonnes per year (usually kilotonnesor million tonnes per year)	t, Mt, Gt tpa, Mtpa
Uranium	Tonnes (usually kilotonnes) of uranium or of uranium oxide	t U; kt U t U_3O_8; kt U_3O_8
Electricity	Capacity: watts, kilowatts, etc Production or use: watt-hours, kilowatt-hours, etc	W, kW, MW Wh, kWh, MWh
Bioenergy bagasse, biomass	Tonnes (or thousands of tonnes)	t, kt

Fuel-specific to standard unit conversion factors

Oil and condensate	**1 barrel**	**=**	**158.987 litres**
	1 gigalitre (GL)	=	6.2898 million barrels
	1 tonne (t)	=	1250 litres (indigenous)/ 1160 litres (imported)
Ethanol	1 tonne	=	1266 litres
Methanol	1 tonne	=	1263 litres
LPG			
average	1 tonne	=	1760 - 1960 litres
naturally occurring	1 tonne	=	1866 litres
Natural gas	1 cubic metre (m^3)	=	35.315 cubic feet (cf)
Liquefied natural gas	1 tonne	=	2174 litres
Electricity	1 kilowatt-hour (kWh)	=	3.6 megajoules (MJ)

Energy content conversion factors

The energy content of individual resources may vary, depending on the source, the quality of the resource, impurities content, extent of pre-processing, technologies used, and so on. The following table provides a range of measured energy contents for gas fuels and, where appropriate, the accepted average conversion factor.

	PJ/Bcf	**MJ/m³**
Natural gas		
• Victoria	1.0987	38.8
• Queensland	1.1185	39.5
• Western Australia	1.1751	41.5
• South Australia, New South Wales	1.0845	38.3
• Northern Territory	1.1468	40.5
Average	1.6282	57.5
Ethane (average)	1.6282	57.5
Town gas		
• synthetic natural gas	1.1043	39.0
• other town gas	0.7079	25.0
• Coke oven gas	0.5125	18.1
• Blast furnace gas	0.1133	4.0

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