

# Cooper-Eromanga Basin Outlook | 2035

October 2016

CORE  
ENERGY  
GROUP







Cooper-Eromanga Basin Outlook | 2035

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## Preface

This study was commissioned by the South Australian Department of State Development's Energy Resource Division (DSD-ERD) and is intended to inform readers regarding the competitive outlook for the Cooper Basin as a major source of supply to eastern Australian gas markets.

Estimates reflect analysis of information to June 2015. Estimates provided exclude any future cost and well performance improvements that will inevitably be targeted by gas suppliers.

The descriptions (in this report) of the extent and in-place volumes of gas and gas liquids in unconventional plays in the Cooper Basin are joint inputs from Geoscience Australia and DSD-ERD.

Throughout this report the term 'Cooper' intends to reference both the established petroleum provinces of the Cooper Basin and overlying Eromanga Basin.

By 2018 annual demand in the eastern Australia ("EA") gas sector will approach approximately 2,000 PJ, rising from a historical high of approximately 700 PJ. This demand requires an underlying reserve of approximately 40,000 PJ to support 20 years of activity and 80,000 PJ if we consider a 40-year outlook, where EA maintains the level of LNG production and grows domestic production. This growth has placed substantial strain on the eastern Australia conventional and coal seam resource base, requiring operators to extend exploration and development activity into areas which are currently less productive and significantly higher cost, including new unconventional play types.

As of June 2015, the Cooper Basin, inclusive of South Australia ("SA") and Queensland ("Qld"), accounts for less than 80 PJ of annual gas production<sup>1</sup> or approximately 12% of the eastern domestic gas market - which could fall to 4% without new development. However, based upon: estimated marginal cost<sup>2</sup> to deliver ex-Moomba gas to eastern Australian markets (including LNG export from Gladstone); current trends towards cost reductions; current strategies to lift productivity; and significant upside to commercialise new gas plays in the Cooper Basin – while possible – this down-side (worst case) scenario is considered a possible but unlikely scenario.

Joint Geoscience Australia and DSD assessments concluded in 2016, giant gas plays (with multi-TCF potential) in unconventional reservoirs in the Cooper Basin. The prospects for converting a part of these discovered unconventional resources to competitive reserves are realistic. Additionally, the May 2016 United States Geological Survey (USGS) estimate of undiscovered technically recoverable gas from conventional reservoirs in the Cooper Basin is 1,017 PJ with a 95% probability range of 537 to 1,723 PJ.

The challenge for the Cooper Basin and all gas producing regions is to confirm new economic reserves and implementing practices that improve average production per well and overall financial productivity of projects. This is an imperative if the Cooper Basin is to remain a significant contributor to the well-being of South Australia for decades to come. In the unexpected case where infill and unconventional programs are not pursued successfully and ex-

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<sup>1</sup> Note that Cooper Basin has additional oil and gas liquids production.

<sup>2</sup> Marginal cost in this report includes all go-forward operating and capital costs associated with developing the resource. This also includes cost of capital at 10%, royalties and taxes. Table 7.1 in this report provides a summary of marginal costs in terms of AUD/GJ.

Moomba production levels continue to fall, fixed costs will begin to challenge economic viability of the Moomba petroleum processing facilities.

To maintain and grow its share of the gas market, the Cooper Basin must demonstrate that it is more attractive to investors and customers than alternative supply regions; primarily CSG in Qld and New South Wales (“**NSW**”). Ultimately, relative cost of gas extraction and delivery to defined demand centres will be the metric used to determine preferences from a supply portfolio perspective.

To a significant extent the market is expected to respond to this opportunity. Numerous companies are exploring for gas (with various levels of petroleum liquids) in conventional and unconventional plays in South Australia. Despite production depletion in the Cooper and Otway basins – exploration of certain conventional plays in South Australia (such as the western flank of the Patchawarra Trough in the Cooper Basin)<sup>3</sup> still reaps relatively high deliverability gas reserves, albeit in modest-in-size wet gas discoveries.

The near-term challenge is the commercialisation of one or more potential large gas accumulations in at least 8 (five in the Cooper and three in the Otway basin) distinct unconventional reservoir plays that have and will be explored in coming years in South Australia. With such a diversity of independent unconventional plays, the chances are high that at least one large accumulation of these unconventional plays will be commercialised. In short, there are realistic expectations for economic success in proving multi-TCF gas reserves in one or more of the unconventional reservoir plays in the Cooper and/or Otway basins. That expected success has the prospects to underpin decades more gas supply from South Australia for both domestic gas and export LNG markets.

This study reveals relative competitive positions for 17 developed gas plays that are already connected to eastern Australian markets, as well as certain gas fields in the Northern Territory for which there are plans to connect to the eastern Australian gas market.

These relative competitive positions pre-date considerable and ongoing efforts on the part of South Australian oil and gas producers to lift productivity and reduce costs. This will nonetheless provide a foundation for further discussion and analysis of the preferred path forward to optimise the value of Cooper Basin gas resources.

**Paul Taliangis**  
Chief Executive  
Core Energy Group Pty. Ltd.

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<sup>3</sup> Includes reference to Santos and Beach exploration success

# 1. Executive Summary

## 1.1 Introduction

Core Energy (“**Core**”) has been engaged by the South Australian Department of State Development’s Energy Resources Division (“**DSD-ERD**”) to undertake an independent assessment of the outlook for oil and gas development and production from the Cooper Basin to 2035. The main focus of the study is an analysis of alternative gas supply sources to meet both domestic and LNG export demand, including an analysis of estimated marginal costs of SA Cooper Basin gas supply relative to competing supply options.

As stated in the Preface, the descriptions of the extent and in-place volumes of gas and gas-liquids in unconventional plays in the Cooper Basin are inputs from Geoscience Australia and DSD-ERD.

## 1.2 Methodology

### 1.2.1 Risk Management Framework

Core has used a risk management framework to define key risk areas as a basis for establishing study focus areas.

### 1.2.2 Market

Core has derived scenarios of gas markets available to Cooper Basin based on existing (as at June 2015) domestic and LNG contracts, and an eastern Australia wide analysis of demand and supply (as at June 2015). More recent (2016) response to lower oil prices, that has stimulated several companies to write down a proportion of their reserves, is not yet reflected in analyses.

### 1.2.3 Existing Development Wells

Core has used historical well performance data to develop a projection of Cooper Basin gas and oil production for existing development wells. This report also reflects public reports of significant recent exploration results – such as the Washington 1 well that confirms prospects for a significant unconventional source rock play<sup>4</sup>.

### 1.2.4 Planned Development Wells

Well type curves have been derived to develop a scenario of future production from new development activity in the: western flank oil program; infill gas program; and unconventional plays. The latter type curve is the median of five potential well profiles considered. If the most productive type curve for wells producing from unconventional reservoirs is used – then the estimated marginal cost could fall to around AUD4/GJ.<sup>5</sup>

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<sup>4</sup> See: <http://www.spenewsaustralasia.org/article.aspx?p=1&id=3735>

<sup>5</sup> Please note this marginal cost includes the cost of capital, assumed to be 10%.

### 1.2.5 Converting Discovered Resource into Reserves

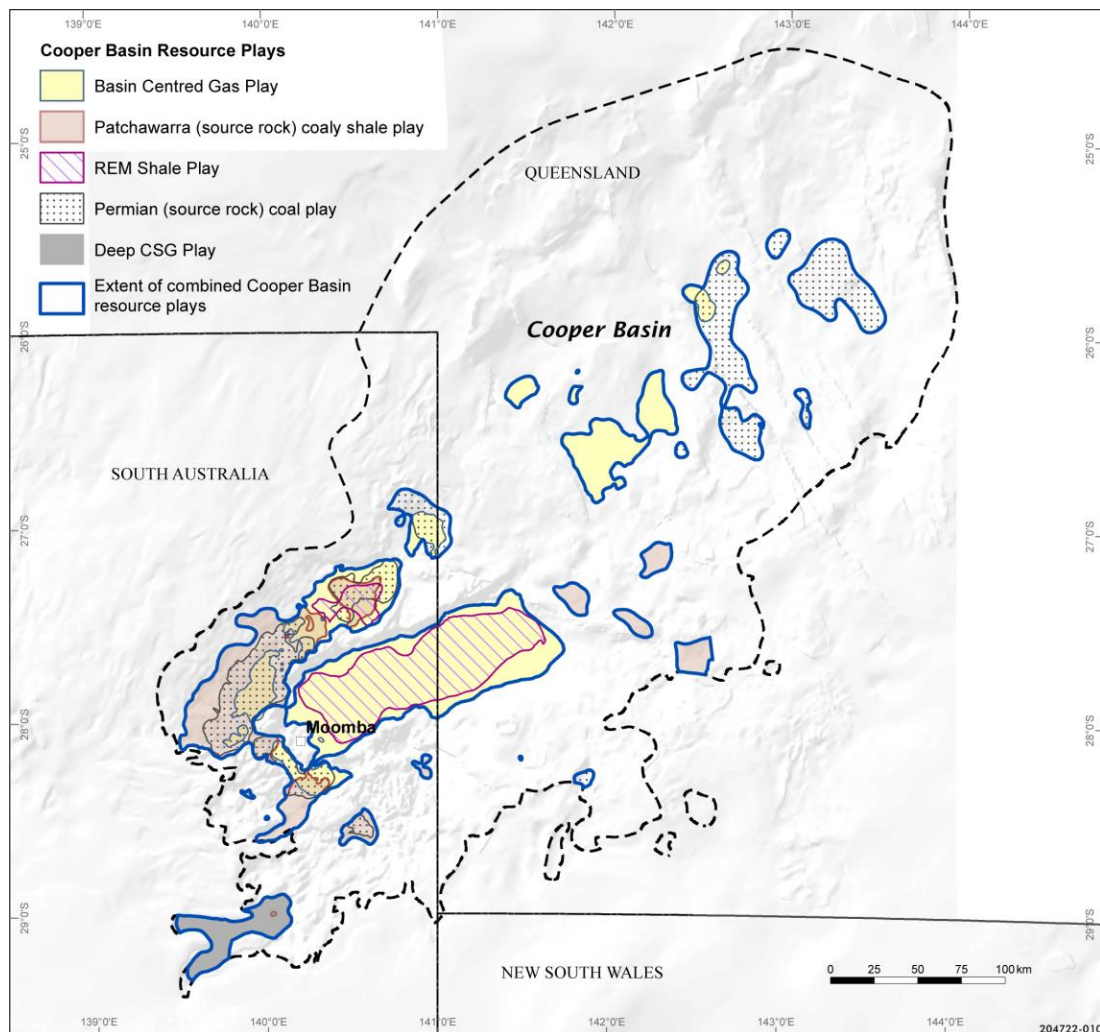
Core Energy refers to The Roadmap for Unconventional Gas Projects in South Australia (DSD-ERD, 2012) for descriptions of gas plays with multi-TCF potential in unconventional reservoirs in the Cooper Basin, conversations with DSD-ERD, and public statements from industry to offer the following statements:

- Deep source rock plays are being explored for in at least three play trends in the Cooper Basin; and
- Tight (low permeability) composite shale siltstone and sandstone reservoirs are being explored for in at least two play trends in the Cooper Basin.

Figure 1.1 locates the five main unconventional reservoirs plays in the SA-Qld Cooper Basin:

- Basin Centred Gas (BCG) Play (shale, siltstone, tight sandstone)
- Roseneath-Epsilon-Murteree (REM) Play (shale, siltstone, tight sandstone)
- Permian (source rock) Coal Play
- Patchawarra (source rock) Coaly Shale Play
- Deep Coal Seam Gas (CSG) Play

Figure 1.1 Cooper Basin Resource Plays Courtesy of DSD-ERD, 2016



The unconventional shale plays in the Cooper Basin have been the subject of two key independent assessments with the potential risked recoverable resource estimated to be between 50 to 80 TCF of gas.<sup>6</sup> The resource potential of the shale and tight gas plays have been assessed by AEMO with a total prospective gas resource in place of approximately 180 TCF.<sup>7</sup>

DSD-ERD has worked closely with Geoscience Australia to develop key datasets including generative potential of 5 actively explored Cooper Basin unconventional resource plays across SA-QLD. Based on these datasets, in February 2016 DSD-ERD documented preliminary deterministic estimates that indicate aggregate potential (across these five plays) in excess of 600 TCF Sales Gas (C1-C5) in Place (GIP) and in excess of 80 billion Bbls of Oil (C6+) in Place (OIP) (Table 1.1). DSD-ERD has advised that probabilistic estimates of technically recoverable resource for each of the 5 actively explored unconventional plays will be advanced in 2016/17.

**Table 1.1 Cooper Basin Resource Play Summary**

Resource assessment based on assumptions as outlined above adopting deterministic methodology (DSD-ERD, as presented by Barry Goldstein to the South Australian Resource Exploration Investment Conference, 20 April 2016).<sup>8</sup>

Basic Data	Resource Play	South Australia					Queensland			
		BCG	REM	Permian coal	Patch coaly shale	Deep CSG	BCG	REM	Permian coal	Patch coaly shale
Physical Extent	Prospective Area (km2)	7202	3169	4031	5124	1031	5116	1996	4274	994
	Avg. Net Thickness (m)	114	90	31	59	170	183	121	18	22
	Depth (m)	>3000	>3000	>2600	>2600	>1400	>3000	>3000	>2600	>2600
Reservoir Properties	Reservoir Pressure	O/press	O/press	Normal	Normal	Normal	O/press	O/press	Normal	Normal
	Porosity (%)	4 - 7	2 - 4	n/a	n/a	n/a	4 - 7	2 - 4	n/a	n/a
	Avg. TOC (wt %)	n/a	2.7 – 3.5	68	33	68	n/a	2.7 – 3.5	68	33
	CO2 (%)	27 - 37	37	30 - 35	35	tbd	27 - 37	37	30 - 35	35
	BGi (scf/rcf)	257	257	205	205	tbd	257	257	205	205
	Thermal Maturity (% Ro)	2 – 3.5	2 -3.5	0.9 – 2.0	0.9 – 2.0	>0.7	2 – 3.5	2 – 3.5	0.9 – 2.0	0.9 – 2.0
Resource	Deterministic OIP (bn bbl)	-	-	39.94	23.59	-	-	-	14.44	2.13
	Deterministic Sales GIP (TCF)	150.54	33.58	113.77	53.15	tbd	208.49	36.80	67.28	5.03

<sup>6</sup> Refer to: AWT International, 2013. Shale Gas Prospectivity Potential. Report prepared for the Australian Council of Learned Academies, viewed 26/05/15, <http://www.acola.org.au/PDF/SAF06Consultants/AWTShale%20Gas%20Prospectivity%20Potential%20Jan2013.pdf> ; and

Energy Information Agency (EIA) 2013. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries outside the United States. U.S. Department of Energy. Washington DC, viewed 23/02/15, <http://www.eia.gov/analysis/studies/worldshalegas/> .

<sup>7</sup> Refer to: AEMO Gas Statement of Opportunity report and related analysis, 2014-2016.

<sup>8</sup> To download this SAREIC presentation – go to [http://petroleum.statedevelopment.sa.gov.au/data/assets/pdf\\_file/0006/274875/SAREIC\\_20\\_April\\_2016\\_-\\_Energy\\_Resource\\_Insights\\_for\\_Investment.pdf](http://petroleum.statedevelopment.sa.gov.au/data/assets/pdf_file/0006/274875/SAREIC_20_April_2016_-_Energy_Resource_Insights_for_Investment.pdf)

To June 2015, a significant number of exploration wells have been drilled to deliberately target unconventional and a number of these explored plays have been the subject of extended flow tests in (more than 50 wells, including both new wells and undertaking tests in pre-existing wells).

Production from the first Cooper Basin shale gas well (Moomba 191) was announced by Santos in August 2012.

On 24 February 2014 – it was announced that Senex Energy and Origin Energy Limited had agreed to evaluate the prospects for gas in tight sandstones, shale and deep coal plays in key areas of South Australia's southern Cooper Basin. This program may involve a work program of up to \$252 million involving the drilling of at least 15 wells and substantial 2D and 3D seismic acquisition programs. This project appears to be a part of the upstream petroleum assets that are offered for sale by Origin Energy in 2016.<sup>9</sup>

On 3 December 2015, Drillsearch Energy stated, "The Washington 1 unconventional exploration well in PEL 570 reached a total depth of 3,660 metres in October and encountered elevated gas shows in the Permian Source Rocks across the Toolachee, Epsilon and Patchawarra formations. In November, the joint venture (Drillsearch 47.5%, Santos 35% and Operator; and Sundance Energy (17.5%) tested all three formations with a five-stage hydraulic stimulation campaign. Measurable gas flows to surface were recorded after only 7 days with the test lasting 38 days. Initial gas flows were encouraging with the well also producing hydrocarbon-liquids towards the end of the test. The well has been shut-in to monitor pressure build-up while the joint venture considers completion options<sup>10</sup>.

The May 2016 United States Geological Survey (USGS) estimate of undiscovered technically recoverable gas from conventional reservoirs in the Cooper Basin is 1,017 PJ with a 95% probability range of 537 to 1,723 PJ, plus 19 million barrels of natural gas liquids with a 95% probability range of 9 to 34 million barrels of natural gas liquids.<sup>11</sup>

### 1.2.6 Cost

Core has developed cash flow models for each competitive supply area to derive and compare cost of production as at 1 July 2015. The relative future competitiveness of alternative gas supplies for various gas markets will obviously depend on future: cost reductions; lifts in productivity; relative distances (via pipelines) of gas supplies to gas markets; commercialisation of new play trends, and volumes of proven plus probable developed gas reserves. Indeed, costs estimated to 1 July 2015 pre-date considerable and ongoing efforts on the part of South Australian oil and gas producers to lift productivity and reduce costs.

### 1.2.7 Strategic analysis

Core has used a strategic analysis framework to analyse the strategic implications of the detailed analysis above.

## 1.3 Risk Management

The study team has identified the major commercial risk addressing the Cooper Basin to be the risk that production is displaced in part or in full by a lower cost source/s to such an extent that gas production from the Cooper Basin is not

<sup>9</sup> Refer to: <http://www.theaustralian.com.au/business/dataroom/origin-energys-800m-assets-selloff-attracts-bidders/news-story/5b88cb5824b4b7d537b11c0e35736473>

<sup>10</sup> For additional insights see: <http://www.spenewsaustralasia.org/article.aspx?p=1&id=3735>

<sup>11</sup> For details see: <https://pubs.er.usgs.gov/publication/fs20163028>



competitive, with follow-on impact on the economics of oil development and production. A down-side (worst-case) scenario sees this (unlikely) possibility eventuate roughly 10 years from 1 July 2015, by 2025.

The potential consequences of this down-side (worst-case) scenario are obvious and include:

- Less supply-side competition in gas markets
- Less government revenue
- Loss of jobs
- Loss of skills, competencies
- Broader economic impacts

Based on: estimated marginal cost analyses to deliver ex-Moomba gas to eastern Australian markets (including LNG export from Gladstone); current trends towards cost reductions; current strategies to lift productivity; and significant upside to commercialise new gas plays in the Cooper Basin – while possible – this down-side (worst case) scenario is not considered a likely scenario.

With significant infrastructure in place, there is an opportunity for new gas plays with favourable geology to be commercially viable.

Based on June 2015 estimates of marginal costs to deliver gas from alternative Australian locations, Cooper Basin gas produced at less than AUD5/GJ can be expected to be competitive domestically and as a supply source for LNG export.

It is likely that at least one of the unconventional plays will be commercialised at a cost that would be competitive in at least domestic markets and possibly for LNG export.

Slowed but continuing investment in exploration and appraisal wells, including re-entering pre-existing wells for incremental completions in unconventional reservoirs, demonstrates that Cooper Basin operators are still seeking to convert resources into proven reserves. Given capital constraints and the historical low prices for oil and gas (where sales are linked to oil prices) this is encouraging; however, the timing of significant development is unclear.

## 1.4 Demand

Core has undertaken an analysis of the market available to Cooper Basin under existing contracts, and determined the extent to which the Cooper Basin can contribute to projected unfulfilled demand in both the domestic and LNG markets. The assessed market includes a Beach Energy contract to supply Origin (17 PJ p.a. from 2016) and a Santos contract to supply GLNG (Horizon contract – 50 PJ p.a. from 2015).

The following graphs show the extent of new production and reserves required to meet unfulfilled demand under two scenarios: existing contract only and existing plus potential, which represent a total of 400 PJ and 1,000 PJ of cumulative production respectively.

Figure 1.2 Existing Contract Only Supply Gap | PJ

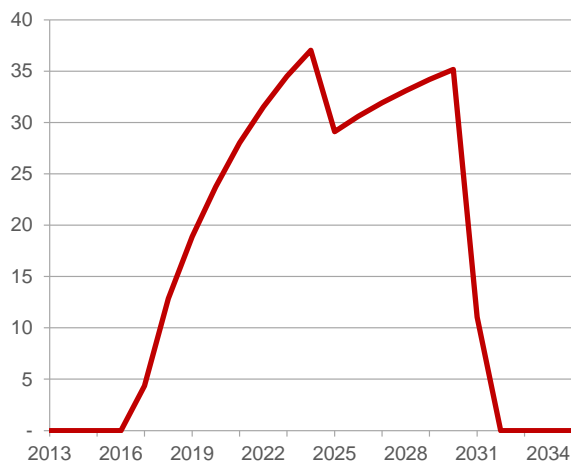
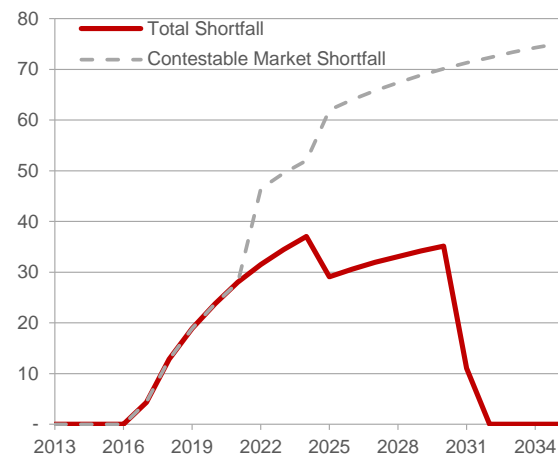


Figure 1.3 Existing + Potential Contract Supply Gap | PJ



## 1.5 Supply

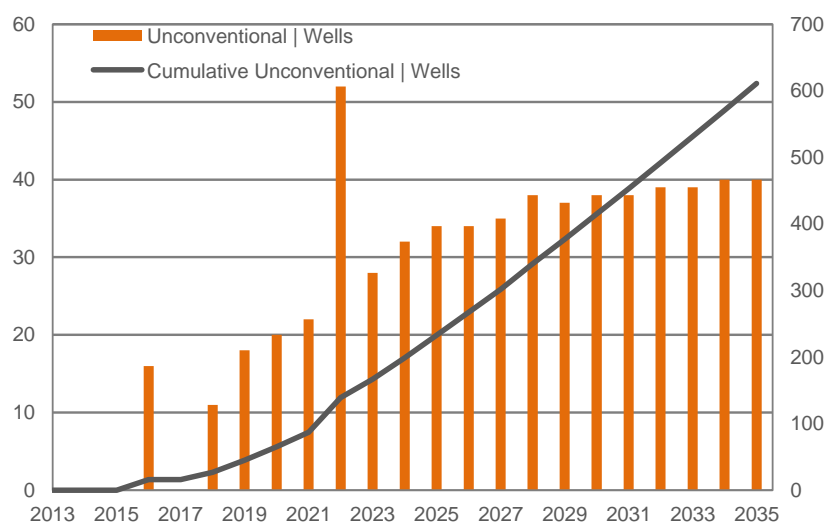
The additional supply needed to meet the gas demand gap will require a significant drilling program regardless of whether it is from the infill program, unconventional plays or a combination of both. To analyse gas supply Core has looked at the production required to meet the total demand gap through developing the unconventional plays. In addition, Core has examined the production scenario where the Cooper Basin Joint Venture meets its existing contracts and the Horizon contract from the infill program.

### 1.5.1 Development Wells into Unconventional Reservoir Plays Required to Meet Demand Gap

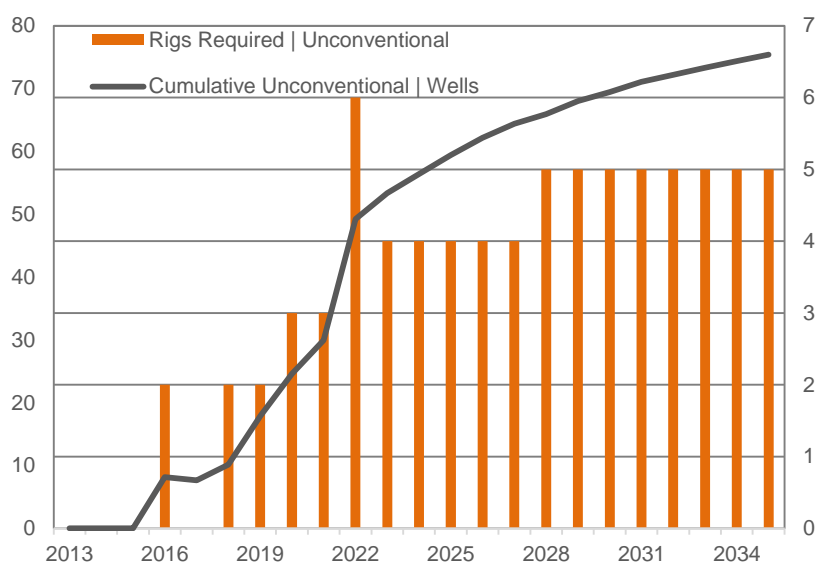
For the unconventional plays in the Cooper Basin to meet the total demand gap it is estimated that over 600 wells would need to be drilled by 2035 to produce over 1,000 PJ. This estimate is based on a well type with an initial rate of 2780 thousand standard cubic feet equivalent per day (mscfe /d) and an estimated ultimate recovery (EUR) of 3.0 bcfe per well.<sup>12</sup> This conservatively assumes that no existing wells are transformed to produce gas from the unconventional resource.

<sup>12</sup> The initial rate is the well's production at the outset which is usually lower than the peak rate. The Estimated ultimate recovery (EUR) is an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well.

**Figure 1.4 Wells targeting gas in unconventional reservoirs required to meet existing plus potential contracts: Annual (left-hand side- "LHS") & Cumulative (right-hand side "RHS")**



**Figure 1.5 Required rigs to meet total shortfall | Unconventional Program | PJ Production (LHS) & Rigs (RHS)**



The prospects for risk-sharing contracts between service companies and producers, and between producers and larger gas buyers are amongst prospective solutions to capital constrained delineation and development programs.

Such arrangements already include:

- Traditional CPI-linked take or pay gas sales contracts at cost plus profit;
- Strike Energy's conditional gas off-take agreements with substantial domestic gas consumers; and
- The Senex Energy and Halliburton arrangement whereby Halliburton covers a significant part of development costs versus revenue participation

Such arrangements could be fostered with greater transparency in relation to volumes of uncontracted, undeveloped proven plus probable reserves. Competition between service companies is also expected to deliver innovative contracts that enhance productivity.

### 1.5.2 Infill Program wells required to meet the existing contracts

If the Cooper Basin Joint Venture requires the infill program to meet existing contracts including Horizon, it will have to drill approximately 400 wells assuming an initial rate of 1200 mscfe/d and a EUR of 2.15 bcfe per well.

Figure 1.6 Infill wells required to meet the existing contracts | Annual (LHS); Cumulative (RHS)

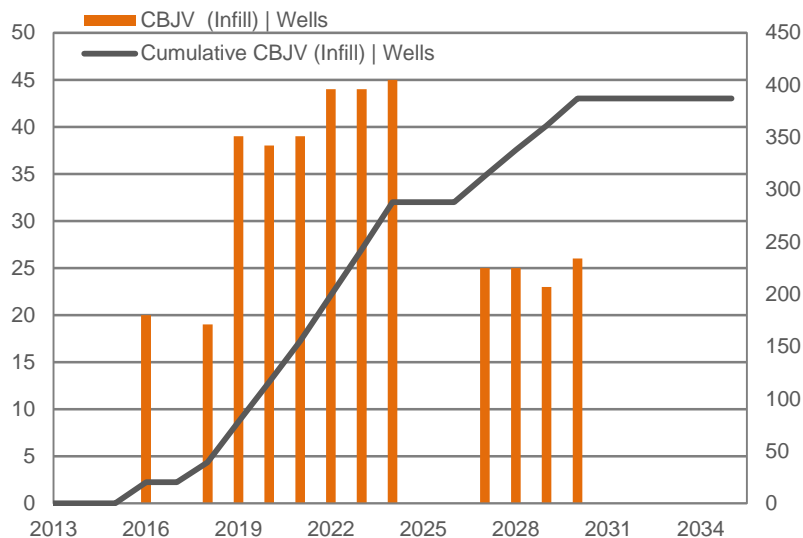
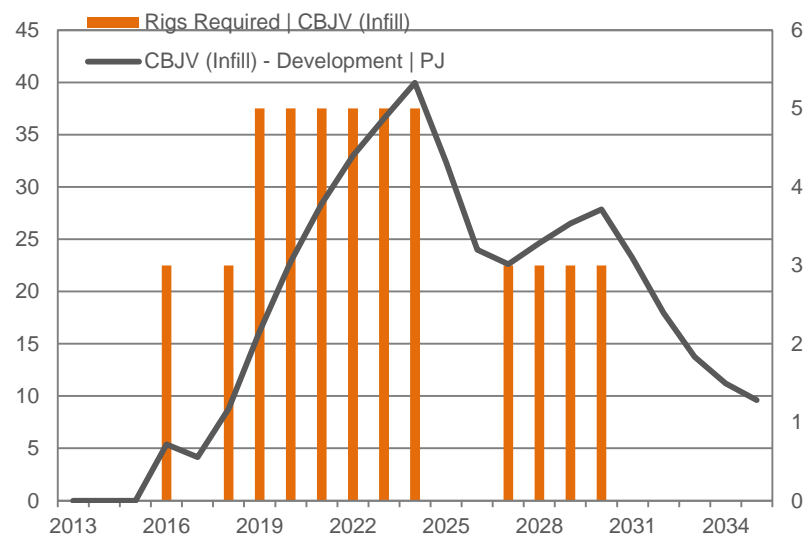


Figure 1.7 Required Rigs to meet existing contracts | Infill Program | PJ Production (LHS); Rigs (RHS)



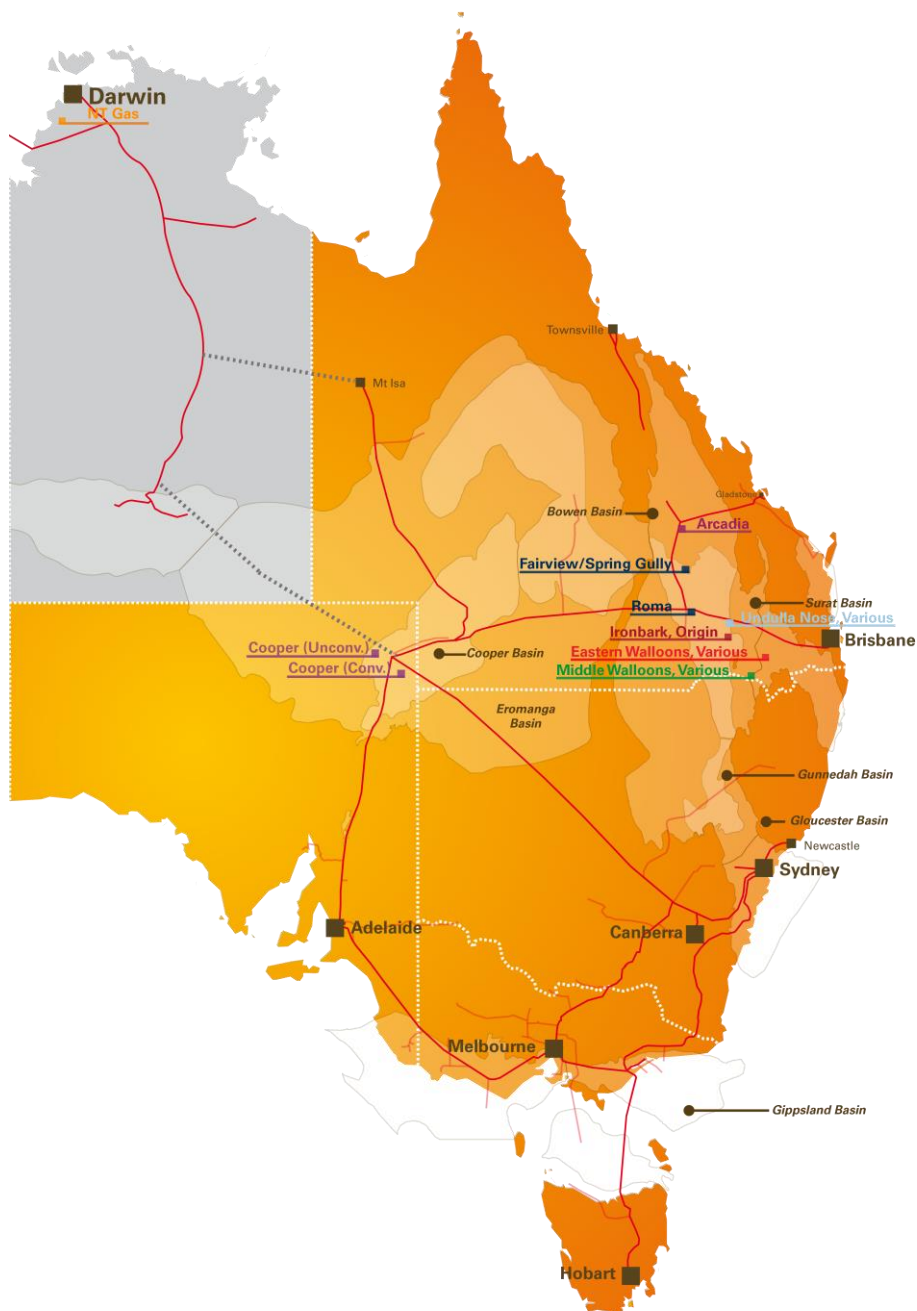
## 1.6 Cost

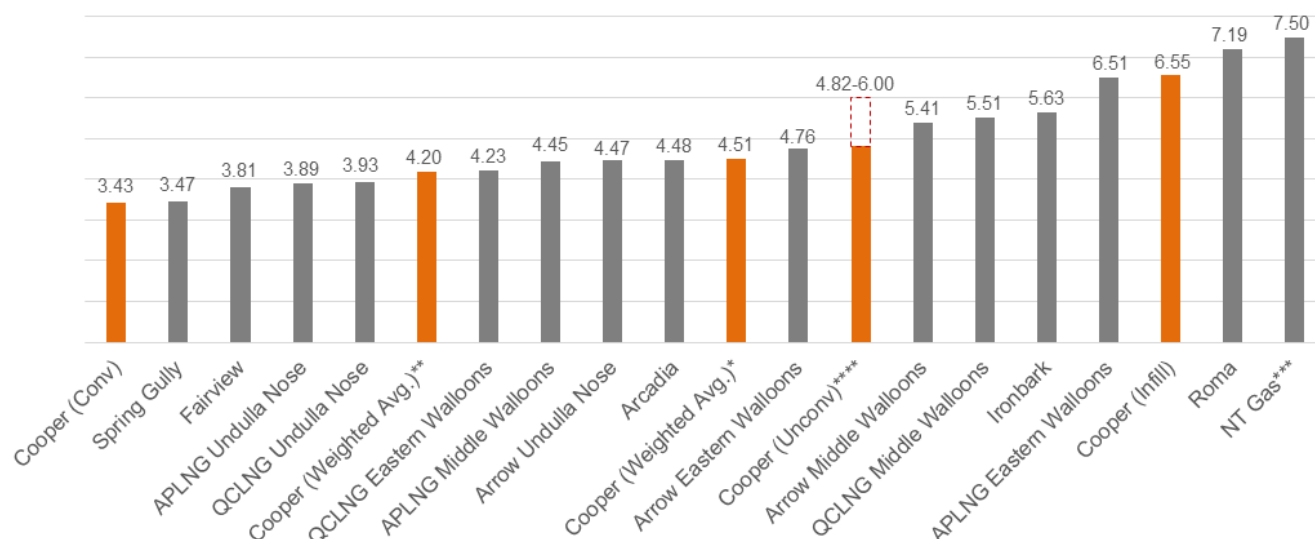
The Cooper Basin must compete against a range of alternative supply sources to ensure market potential is realised. Core has undertaken an analysis of the relative marginal cost of production (ex-gas field) for all major supply sources as summarised below.<sup>13</sup> This analysis highlights the relatively low cost of production of existing development wells,

<sup>13</sup> Core has proprietary models for all the main Queensland CSG supply fields, and bases the input assumptions on publicly available information, third party expert opinions and operator verification. The analysis includes cost of capital which is assumed to be 10%.

the relative low to mid cost of supply of certain unconventional plays and higher cost of the proposed future Cooper Basin gas infill program.

Figure 1.8 Gas Supply Regions



**Figure 1.9 Comparison of Cooper Basin and Competitor Marginal Cost of Supply (ex-field) | AUD/GJ**

\* Represents the weighted average of the CBJV Conventional gas and the CBJV infill program, under the assumption that infill gas would meet the existing horizon contract shortfall.

\*\* Represents the weighted average of the CBJV Conventional gas and unconventional plays, under the assumption that gas from unconventional reservoirs would meet the existing horizon contract shortfall and the contestable market.

\*\*\* NT Gas is estimated to have a range of AUD6/GJ (Blacktip ex-field) to AUD7.50/GJ for the higher cost unconventional plays.

\*\*\*\* Unconventional Cooper supply is estimated to have a cost of AUD4.82/GJ based on global best practice. In reality, this cost could be closer to AUD 6/GJ.

Also note that the type well used for the unconventional plays in the Cooper Basin is the median of five potential well profiles considered. If the most productive well is used the marginal cost could fall to around \$4 per GJ.

**Table 1.2 Estimated Delivered Prices, by Gas Play, by Select Eastern Demand Point | AUD/GJ**

Gas Play	VTS <sup>14</sup>	Adelaide	Sydney	Wallumbilla	Mt Isa
Cooper (Conv)	4.43 plus NVI tariff	4.15	4.43	4.33-4.83	5.24
Spring Gully	5.87 plus NVI tariff	5.59	5.87	3.47	6.18
Fairview	6.21 plus NVI tariff	5.93	6.21	3.81	6.52
APLNG Undulla Nose	6.29 plus NVI tariff	6.01	6.29	3.89	6.60
QCLNG Undulla Nose	6.33 plus NVI tariff	6.05	6.33	3.93	6.64
Cooper (Weighted Avg.)**	5.20 plus NVI tariff	4.92	5.20	5.10-5.60	6.01
QCLNG Eastern Walloons	6.63 plus NVI tariff	6.35	6.63	4.23	6.94
APLNG Middle Walloons	6.85 plus NVI tariff	6.57	6.85	4.45	7.16
Arrow Undulla Nose	6.87 plus NVI tariff	6.59	6.87	4.47	7.18
Arcadia	6.88 plus NVI tariff	6.60	6.88	4.48	7.19
Cooper (Weighted Avg.)*	5.51 plus NVI tariff	5.23	5.51	5.41-5.91	6.32
Arrow Eastern Walloons	7.16 plus NVI tariff	6.88	7.16	4.76	7.47
Cooper (Unconv)	5.82 plus NVI tariff	5.54-6.72	5.82-7.00	5.72-7.40	6.63-7.81
Arrow Middle Walloons	7.81 plus NVI tariff	7.53	7.81	5.41	8.12
QCLNG Middle Walloons	7.91 plus NVI tariff	7.63	7.91	5.51	8.22

<sup>14</sup> The Victorian Transmission System ("VTS") is the transmission network across Melbourne and rural Victoria. The NSW-Vic Interconnect ("NVI") is the transmission pipeline running between Victoria and NSW, connecting the VTS and the Moomba to Sydney Pipeline.



Gas Play	VTS <sup>14</sup>	Adelaide	Sydney	Wallumbilla	Mt Isa
Ironbark	8.03 plus NVI tariff	7.75	8.03	5.63	8.34
APLNG Eastern Walloons	8.91 plus NVI tariff	8.63	8.91	6.51	9.22
Cooper (Infill)	7.55 plus NVI tariff	7.27	7.55	7.45-7.95	8.36
Roma	9.59 plus NVI tariff	9.31	9.59	7.19	9.90
NT Gas	11.86 plus NVI tariff	11.58	11.86	11.76	9.05

The following assumptions were made when calculating the figures in the table above:

- The cost of NT Gas price is assumed to be AUD 7.50 when delivered into the NEGI at Tennant Creek.
- Transmission costs for the Queensland plays are calculated ex-Wallumbilla. No cost is added to account for delivery into Wallumbilla- some projects own pipelines that deliver into Wallumbilla while some projects rely on third party pipelines and will face external tariffs. Due to the insufficient transparency in gas pipeline contracting and transactions, transmission costs presented here are an estimate of the cost typically incurred via arm's-length negotiations or publically disclosed charges.<sup>15</sup> Cooper Basin producers with existing capacity between Wallumbilla and Gladstone could potentially be transporting gas at marginal or written-down transmission costs.
- The tariff for the NVI is not publically available and will be incurred when gas is transported into the VTS via the MSP. Core has noted where this cost would be incurred.

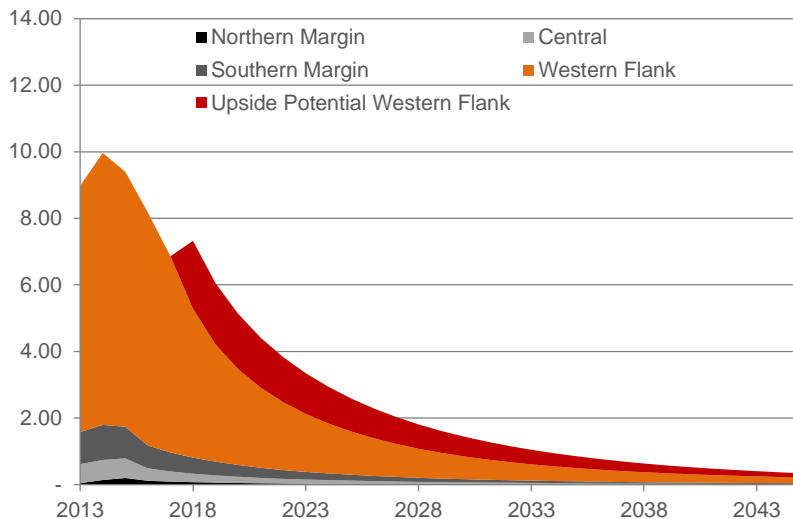
## 1.7 Oil Production

The study team has also undertaken a detailed analysis of the outlook for oil production, in light of the operational relationship between oil and gas production.

A projection of oil production enables an assessment to be made of the allocation of operating costs between gas and oil production, which in turn enables an assessment of per unit gas cost over time and projected royalties.

The following figure demonstrates the significant level of potential oil production, and this study will demonstrate that the future of the Cooper and Eromanga basins is highly leveraged to performance of the Western Flank oil program or new exploration success.

<sup>15</sup> ACCC, East Coast Gas Inquiry, released April 2016; Pipeline operators were described as holding/exercising market power and operating with information asymmetries.

**Figure 1.10 SA Production by Region (actuals to June 2015, forecasts beyond) | MMboe**

## 1.8 Financial Projections

### 1.8.1 Revenue

The Cooper and Eromanga basins have the potential to generate substantial future revenue from oil, gas and gas liquids production as summarised in the following figure. However, it is important to note the significant difference between existing base production (including Western flank) and potential gas production (to meet the reference demand), the latter being essentially at risk without successful exploration and development investment. The difference between the estimated forecast revenue with and without the potential new production is close to AUD500 million per annum from 2020 to 2035.

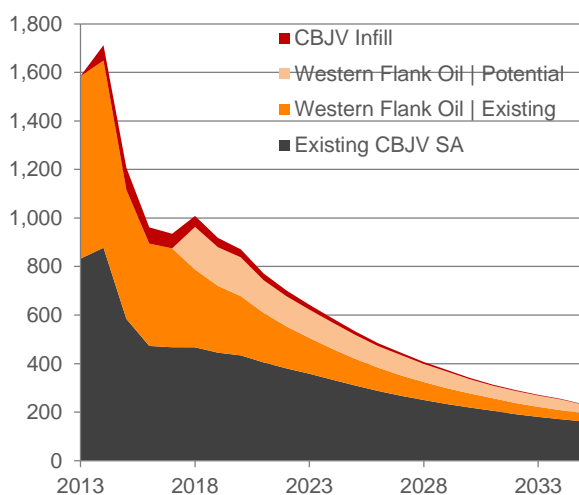
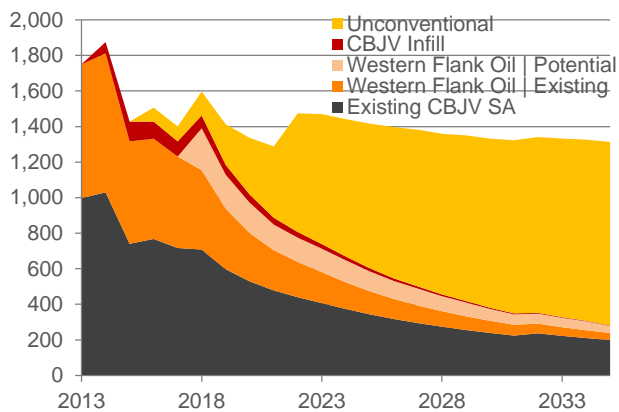
**Figure 1.11 Existing Cooper Revenue | AUDm**

Figure 1.12 Potential Cooper Revenue | AUDm



### 1.8.2 Potential Royalties

Without increased production, lower costs and/or higher product prices, base royalties are projected to fall toward \$60 million p.a. from 2020 and falling progressively if production is not supplanted and/or product prices rise. Success from the unconventional plays, new Western flank activity and other programs will be required to keep royalties above \$60 million to 2025. Figure 1.13 shows the projected royalties from existing production declines, while Figure 1.14 illustrates the ability for royalties to be maintained if the unconventional programs are successful and further potential for oil discoveries in the Western Flank is realised.

Figure 1.13 Royalties from existing production sources | AUDm

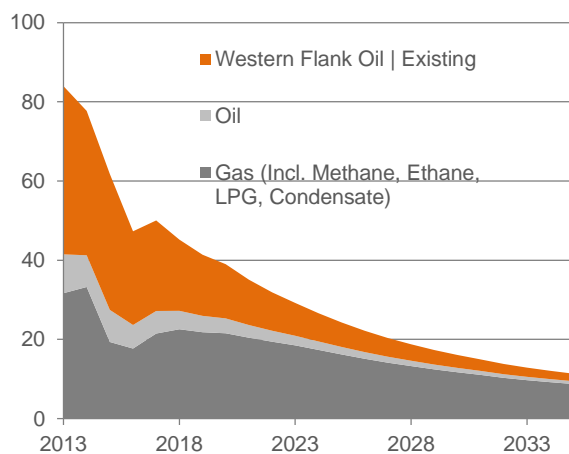
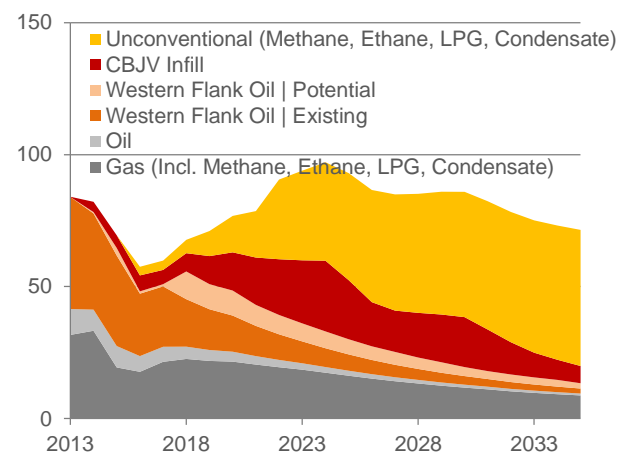


Figure 1.14 Potential Royalties | AUDm



## 1.9 Strategic Analysis

### 1.9.1 The Challenge

The Cooper Basin faces a major strategic challenge in the form of a changing competitive landscape, characterised by tightening gas supply (in part due to capital constraints), potential increasing demand, the uncertain duration of low oil prices and relatively high gas extraction costs while on learning curves in new gas plays.

Under the worst-case, (albeit low chance) downside scenario, the Cooper Basin as a whole will face the test of economic viability by 2025 as the lower gas stream from the existing reserves-base is unable to wear operating costs (without cost reductions and/or increased productivity).

### 1.9.2 Action Plan

The optimisation of Cooper Basin performance will require a co-operative approach between governments, petroleum licence holders, service companies and prospectively, larger industrial consumers of gas. This coincides with plans by at least Origin to explore an opportunity to sell its Cooper Basin interests, and AGL's stated plans to decision to shut down its gas exploration and production business<sup>16</sup>. Key constructive steps jointly lead by industry and governments include:

- Discussions with producers to share projections and understand variances (greater transparency);
- Develop detailed understanding of development and exploration plans/programs;
- Develop understanding of operating cost, and in particular fixed cost components;
- Identify and deploy new operations and development approaches;
- Continue to monitor performance of competitive supply sources;
- Determine priorities to optimise short term Cooper Basin activity;
- Demonstrate through operations that efficient regulation is effective, consistent and trustworthy; and
- Potential need for a renewed international marketing program to attract investment and attain new export contracts.

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<sup>16</sup> For details, see: <https://www.agl.com.au/about-agl/media-centre/article-list/2016/february/review-of-gas-assets-and-exit-of-gas-exploration-and-production>

## 2. Introduction

Core Energy (“**Core**”) has been engaged by Department of State Development’s Energy Resource Division (“**DSD-ERD**”) to undertake an independent assessment of the outlook for oil and gas development and production from the Cooper Basin to 2035. The main focus of the study is an analysis of competition between alternative gas supply sources to meet both domestic and LNG export demand, including an analysis of the cost of SA Cooper Basin gas supply relative to competing alternatives.

This study will provide important input to an understanding of alternative scenarios of future SA Cooper Basin activity and any implications for the broader SA economy.

This study is focused primarily on Cooper Basin gas, however it also addresses oil and gas liquids due to the significant contribution of these products to the fixed cost base of Cooper Basin operations, and their role as contributors to total Cooper Basin royalties and broader economic value.

From a gas market perspective, the study focuses on three primary factors:

- The contestable gas market available to the Cooper Basin (domestic and LNG)
- The potential production stream of both gas and oil
- The cost of Cooper Basin gas supplies relative to alternatives

Key deliverables include:

- Presentation of future supply scenarios
- Assessment of forecast royalty income
- Assessment of broader economic implications

### 3. Methodology

To develop an independent view of the Cooper Basin, that combines strategic insight with a robust fact base and analysis, the following approach was adopted.

- **Risk Assessment** - an evaluation of the Cooper Basin was initially undertaken to highlight competitive threats and potential opportunities for Cooper Basin stakeholders. This defined the focus areas for the study.
- **Well and Field Data Analysis** - data from each individual well was used to develop a bottom-up model to analyse historic oil and gas production. Core grouped the data by fields, license areas and operators to gain a detailed understanding the production areas and trends in well productivity.
- **Production Profiles** - A decline analysis was undertaken to establish reference oil and gas production profiles for each of the defined production groups based on the existing wells in the Cooper Basin and prospective development areas.
- **Demand and Supply Allocation** – demand focused on three elements; the existing domestic Cooper Basin contracts, the Horizon GLNG contract, and the contestable market beyond the Horizon GLNG contract. An assessment of modelled production to fulfil each successive demand tranche was undertaken to determine the production shortfall, and the level of requirement for further development of the resource.
- **Cost Analysis** – costs for the Cooper Basin and all competing supply sources were modelled to evaluate the competitiveness of Cooper Basin relative to alternative supply sources. Costs in this report were estimated to 1 July 2015, and pre-date considerable and ongoing efforts on the part of South Australian oil and gas producers to lift productivity.
- **Strategic and Economic Assessment** – key insights from the analysis and modelling undertaken in prior work steps were reviewed within a strategic and economic context.



## 4. Cooper Basin Overview

### 4.1 Introduction

The Cooper Basin, and overlying Eromanga Basin, host Australia's largest onshore oil and gas development. The Basin extends across South Australia and Queensland, however the majority of production is now from the South Australian acreage. The Basin produces oil and gas and a significant portion of historical gas has been produced with associated liquids.

The Cooper Basin contains approximately 150 gas fields and 90 oil fields currently on production. These fields contain approximately 700 producing gas wells and more than 360 producing oil wells which feed into production facilities at Moomba in South Australia and Ballera in Queensland through approximately 5,600 kilometres of pipelines and flowlines via 15 major satellite facilities incorporating field boost compression (65 satellite compressors, 15 nodal compressors).

The Moomba facility also incorporates a substantial 85PJ of underground storage for processed sales gas and ethane, while Ballera has the 10PJ Chookoo underground storage system for processed sales gas.<sup>17</sup> These storage facilities can be utilised to serve the peak portion of Southern markets as well as by LNG projects requiring volumes of gas to safeguard against production volatility.

Natural gas liquids are recovered via a refrigeration process in the Moomba plant and sent together with stabilised crude oil and condensate via pipeline to Port Bonython near Whyalla, South Australia.

Ethane is sent to Qenos in Sydney via a dedicated pipeline. Sales gas is sent to Adelaide and Sydney via pipelines from Moomba and sales gas is sent to Mt Isa and to Brisbane via pipeline.

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<sup>17</sup> Core Energy Group, Gas Storage Facilities- Eastern and South Eastern Australia, February 2015.

## 4.2 Key Features

Key technical and operational features are summarised in the following table.

**Figure 4.1 Key Feature of Cooper-Eromanga Basins**

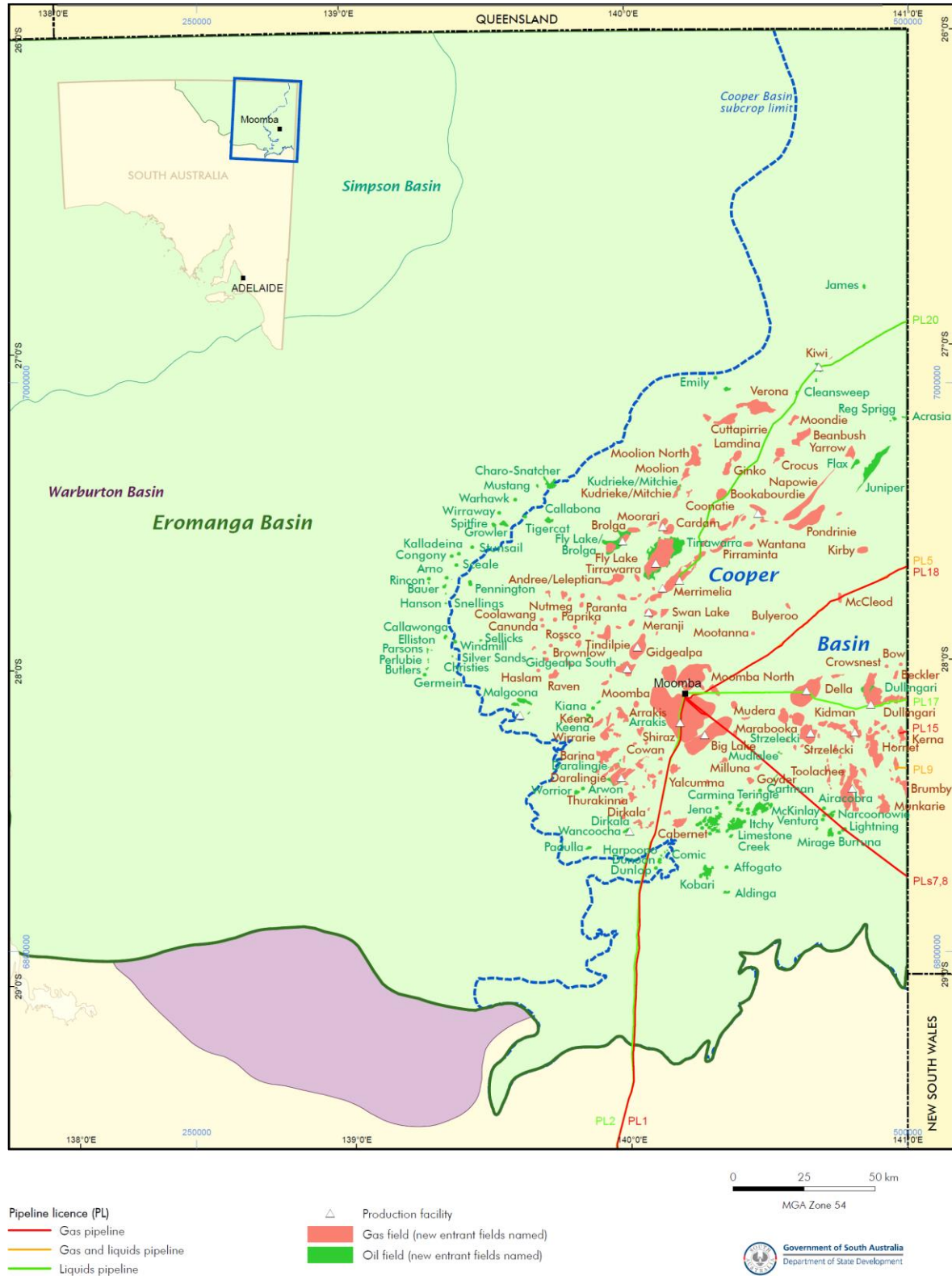
<i>Age</i>	Late Carboniferous - Middle Triassic
<i>Area in South Australia</i>	35,000 km <sup>2</sup> (13 510 sq miles)
<i>Exploration Well Density</i>	1 well per 58km <sup>2</sup> (well per 23 sq. miles)
<i>Success Ratio (conventional plays)</i>	0.442
<i>Depth to target zone</i>	1,250 – 3,670m.
<i>Thickness</i>	2,500m.
<i>Hydrocarbon shows</i>	Widespread over 8 formations.
<i>First commercial discovery</i>	1963 gas (Gidgealpa 2).
<i>Current Production (June 2015)</i>	<b>Cumulative Production</b> - 5.30 TCF sales gas (since 1970), 944.5 mmbbl oil (from 1983), 82.0 mmboe LPG (from 1984), 80.0 mmboe condensate (from 1983)  <b>Annual Production (2013-2014)</b> - 57.92 bcf sales gas, 11.1 mmbbl oil, 1.38 mmboe LPG, 1.12 mmboe condensate
<i>Basin type</i>	Intracratonic.
<i>Depositional setting</i>	Non-marine.
<i>Reservoirs</i>	Fluvial, deltaic, shoreface sandstones.
<i>Regional structure</i>	Faulted anticlines.
<i>Seals</i>	Lacustrine shale, coal.
<i>Source rocks</i>	Carbonaceous shale, thick (up to 30m) coal.
<i>Number of wells (August 2015)</i>	Over 2,000 (1201 development/appraisal)
<i>Seismic line km</i>	76,135 line-km 2D; 14,416 km <sup>2</sup> 3D (94,312 km)

Source: Department of State Development Energy Resource Division

### 4.3 Major Oil and Gas Fields

The following figure summarises significant oil and gas fields within the South Australian Cooper and Eromanga basins.

Figure 4.2 Oil and Gas Fields | Cooper and Eromanga Basins



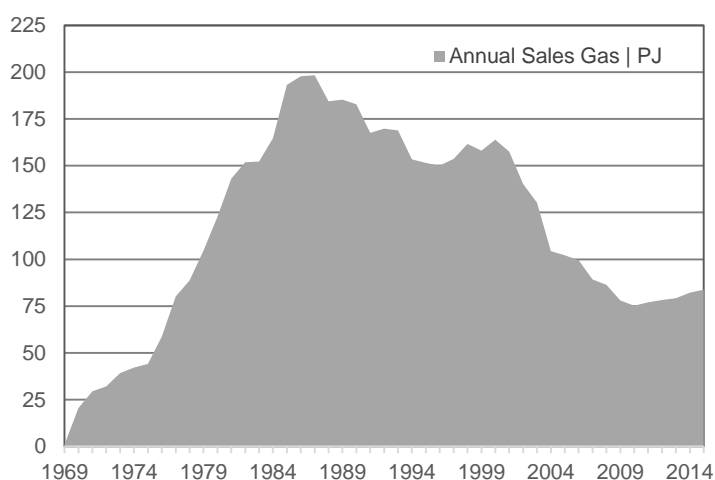
Source: Department of State Development Energy Resource Division

For the purposes of this report, activity is divided between conventional and unconventional play areas. These are addressed separately in the following text.

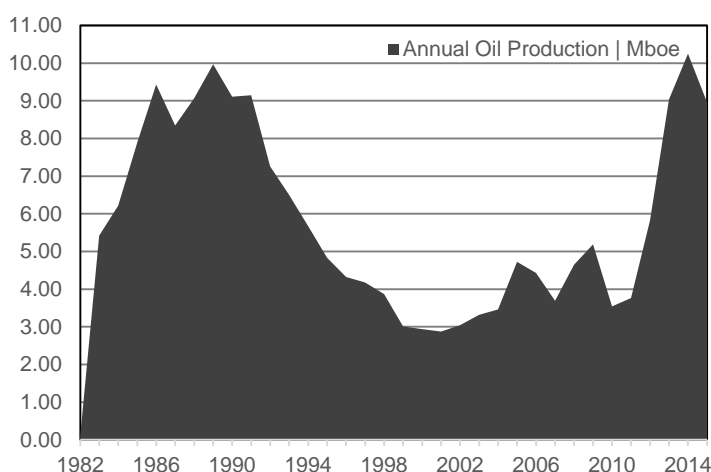
## 4.4 Historical Production

The following charts summarise the historical gas and oil production of the South Australian Cooper and Eromanga basins.

**Figure 4.3 Annual Sales Gas | PJ**



**Figure 4.4 Annual Oil Production | Mboe**



## 4.5 Exploration History and Potential

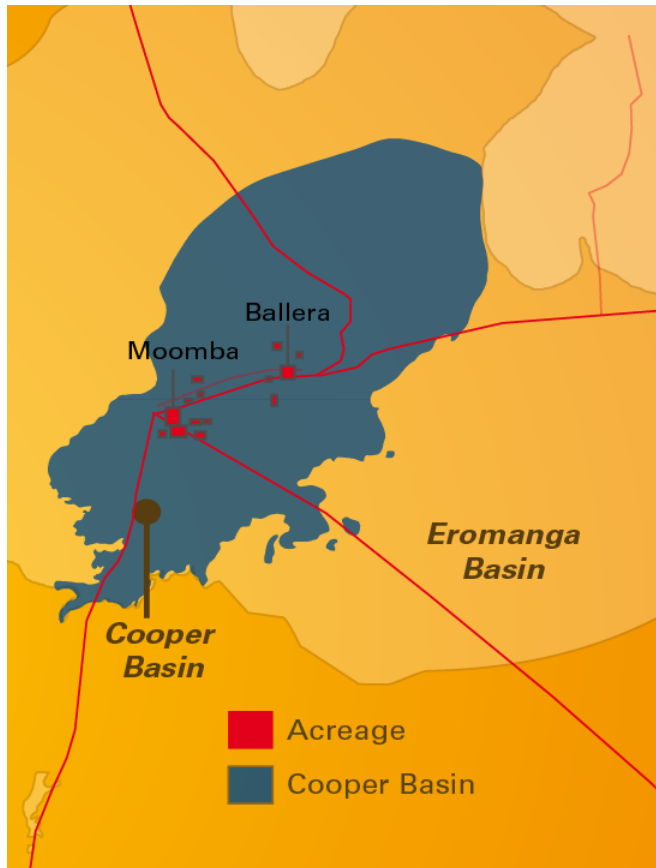
### 4.5.1 Recent Exploration Success

Based on DSD-ERD advice, since January 2002 through to May 2016, 261 exploration wells and 148 appraisal/development wells have been drilled by new explorers in the Cooper Basin. Most exploration wells have targeted oil, however both oil and gas have been discovered. The new entrants found new pools in 120 of these wells

(46% technical success rate) and 107 were cased and suspended as future producers (41% commercial success rate).

#### 4.5.2 Cooper Basin | Conventional Exploration Play Areas

Figure 4.5 Cooper Basin



The conventional gas plays are mature with evidence of material decline over recent years. Most of the remaining reserves are held by joint venture participants Santos (~67%), Beach (~20%) and Origin (~13%).

The allocation of reserves/ future production varies between venturers with Santos favouring sales to GLNG, Origin favouring the domestic market and Beach selling into either market to optimise value but to date has contracted with Origin and thus into the domestic market.

Production in 2015 was approximately 70PJ and remaining reserves stood at approximately 1,600PJ.

Source rocks are carbonaceous shale and thick (up to 30 m) coal.

The main gas reservoirs occur primarily within the Patchawarra Formation (porosities up to 23.8%, average 10.5%; permeability up to 2500 mD) and Toolachee Formation (porosities up to 25.3%, average 12.4%; permeability up to 1995 mD).

Shoreface and delta distributary sands of the Epsilon and Daralingie formations are also important reservoirs.

Conventional play types include anticlines, fault traps and structural-stratigraphic traps.

Over 2,000 wells have been drilled within the Basin.

Approximately 190 gas fields and 700 gas wells are in production.

### 4.5.3 Cooper Basin | Unconventional Exploration Play Areas

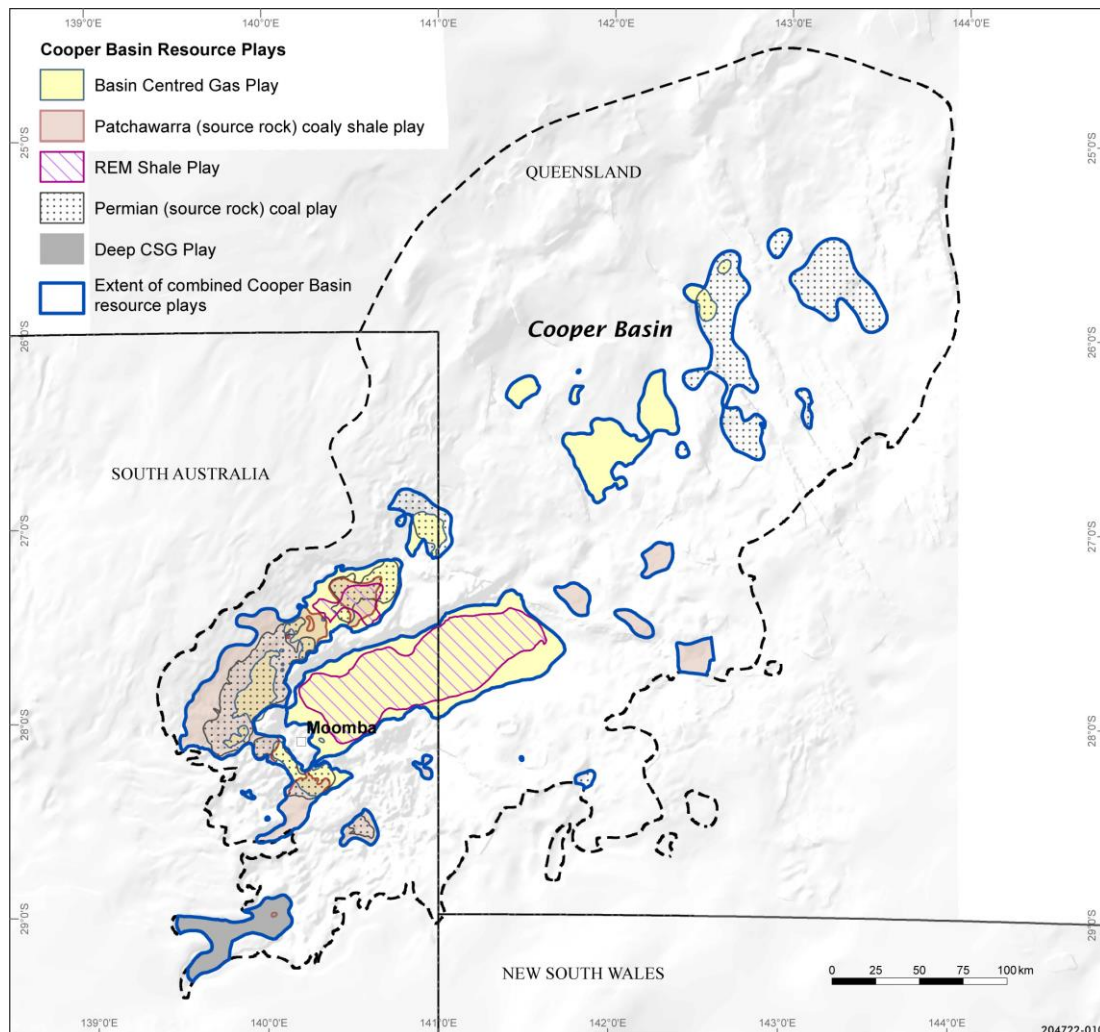
Since late 2011, and most recently, potentially very large unconventional resources in unconventional reservoirs have been the focus of gas exploration.

Five unconventional plays are being actively explored in the Cooper Basin:

- Basin Centred Gas (BCG) Play (shale, siltstone, tight sandstone)
- Roseneath-Epsilon-Murteree (REM) Play (shale, siltstone, tight sandstone)
- Permian (source rock) Coal Play
- Patchawarra (source rock) Coaly Shale Play
- Deep Coal Seam Gas (CSG) Play

Each of these plays has multi TCF potential but are yet to be fully appraised as a precedent to development. It is noteworthy that Chevron withdrew from a major venture in early 2015 while the pre-existing licence holders are still exploring high graded plays. To date a number of wells in South Australia have had extended production tests that are promising in relation to prospective development of some of these plays.

**Figure 4.6 Cooper Basin Resource Plays (courtesy of DSD-ERD, 2016)**

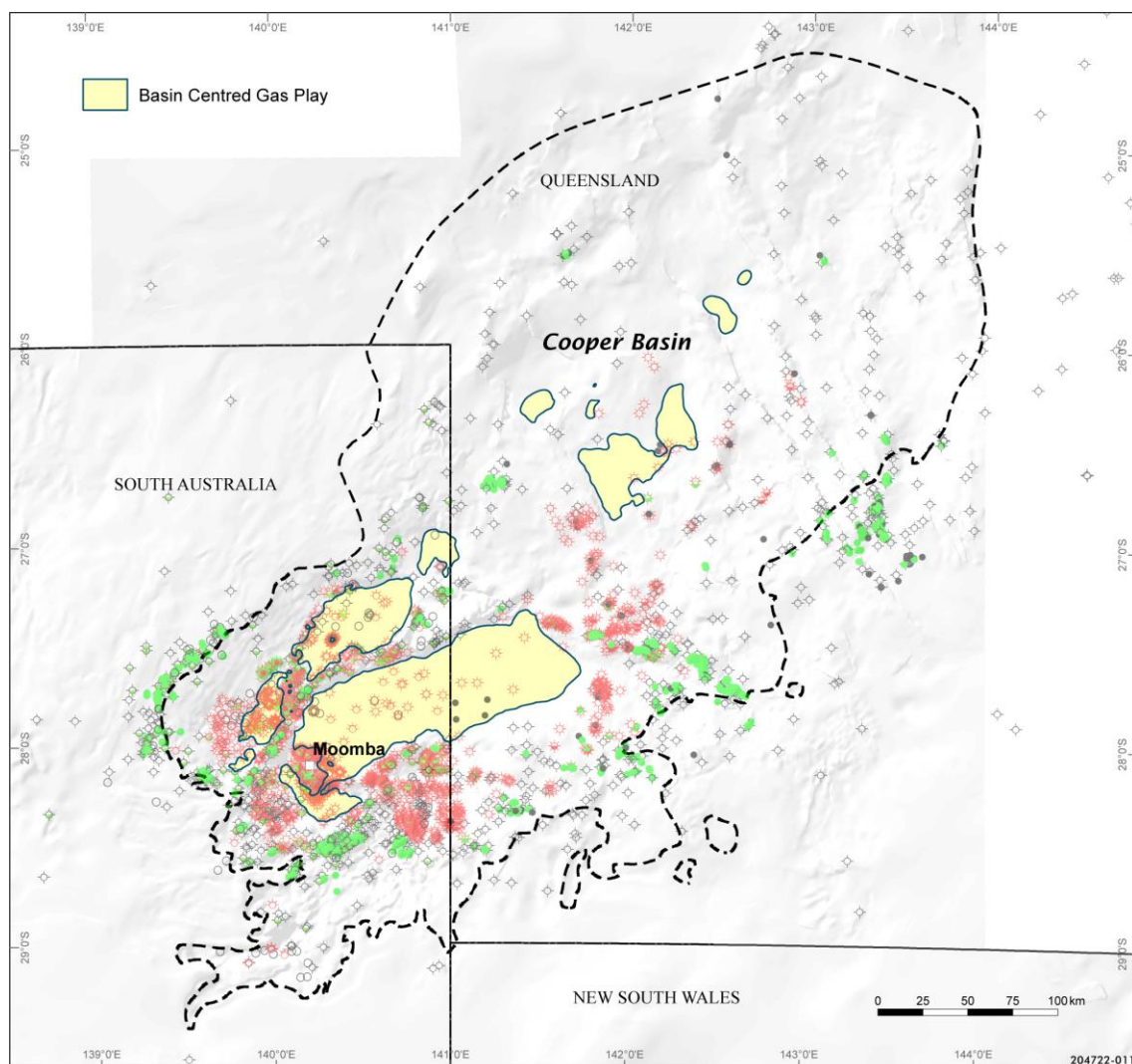




#### 4.5.4 Basin Centred Gas (BCG) Play (shale, siltstone, tight sandstone)

A number of companies including the Santos operated Cooper Basin Joint Ventures in both South Australia and South West Queensland, Senex Energy in partnership with Origin Energy in the Patchawarra, Nappamerri and Allunga Troughs in SA, and Real Energy in the Windorah Trough in Queensland are actively appraising gas in tight sandstones associated with conventional trapping mechanisms in Permian strata throughout the basin. Basin centred gas accumulations in the Nappamerri Trough are a primary focus for Beach Energy's exploration efforts. The Santos operated South Australian Cooper Basin Joint Venture is investigating well spacing, pad drilling, multi-stage fracture stimulation and microseismic monitoring to improve commerciality of the resource and increase recovery factors. At least 3 sub-play areas have been identified, including the Nappamerri-Allunga-Wooloo trough areas, 4 separate areas in the Patchawarra Trough, and more than 4 distinct areas in the Windorah Trough in Queensland.

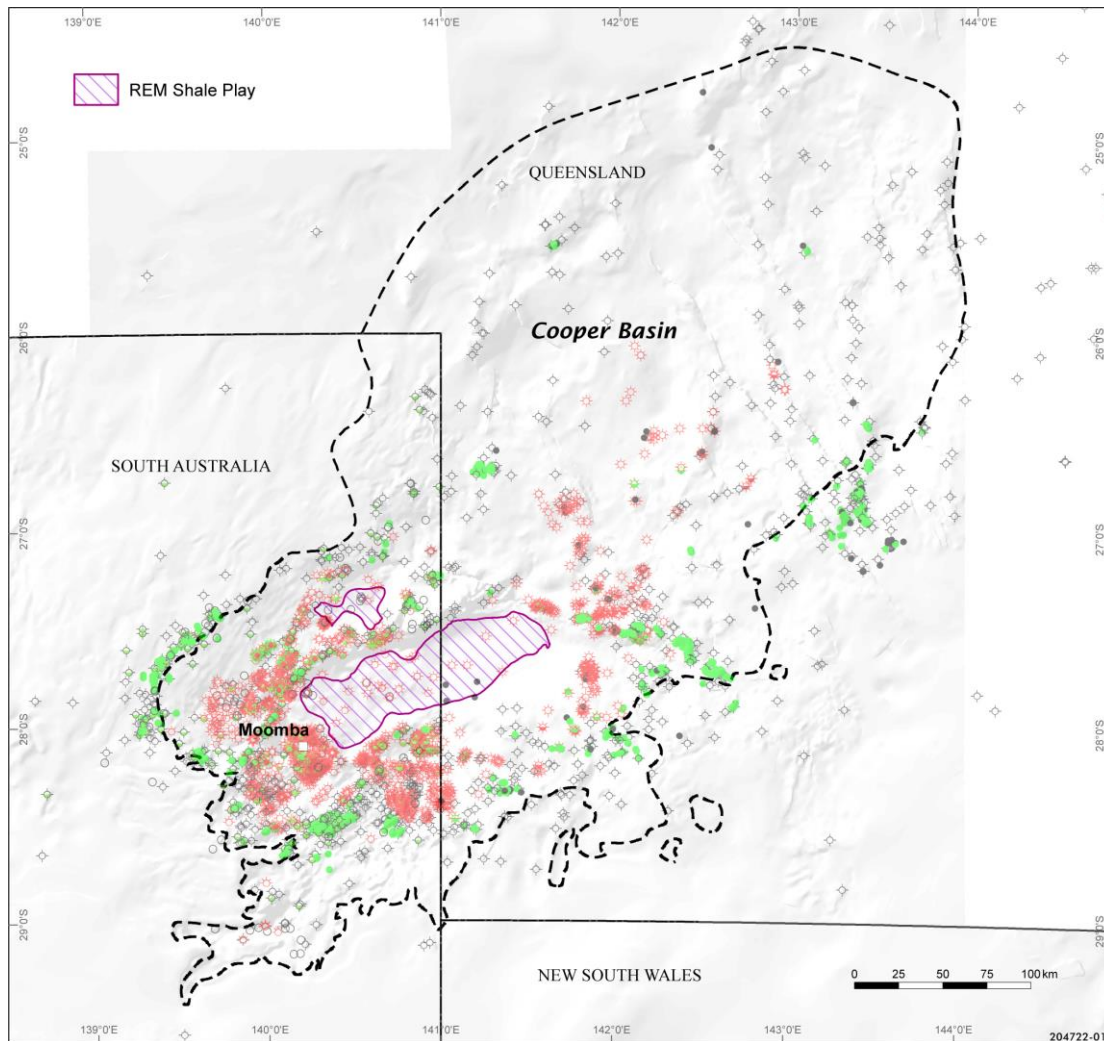
Figure 4.7 Cooper | Basin Centred Gas Play (courtesy of DSD-ERD, 2016)



#### 4.5.5 Roseneath-Epsilon-Murteree (REM) Play (shale, siltstone, tight sandstone)

The principal shale gas exploration program has been the Roseneath - Epsilon - Murteree (REM) play comprising Early Permian Murteree and Roseneath shales divided by tight sandstones of the Epsilon Formation. The two shale units are thick, generally flat lying, and laterally extensive, comprising siltstones and siliceous (and sideritic in part) mudstones deposited in large and relatively deep freshwater lakes. Sub-plays include the Nappamerri and Patchawarra trough areas.

Figure 4.8 Cooper | REM Shale Play (courtesy of DSD-ERD, 2016)

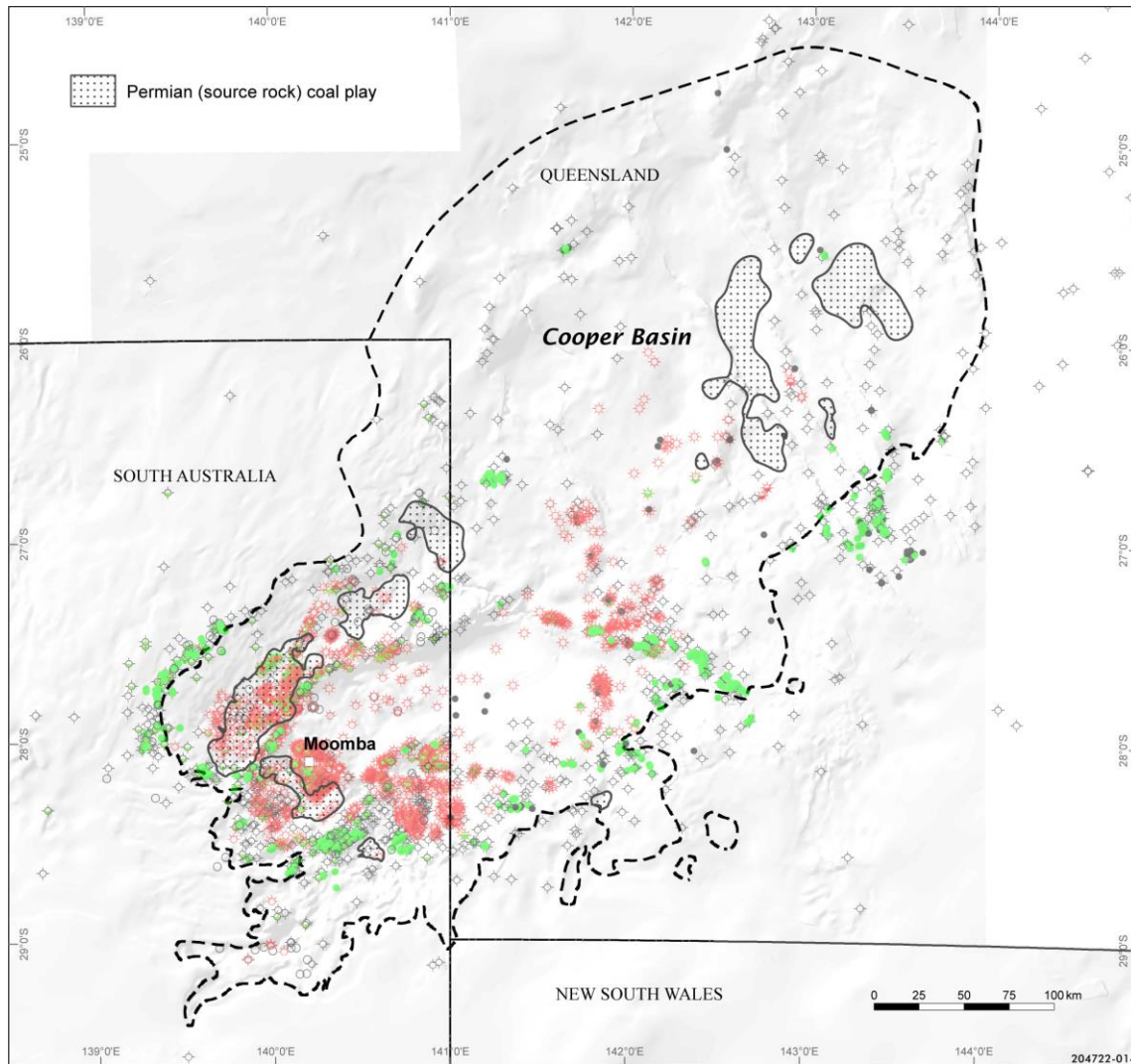




#### 4.5.6 Permian (source rock) Coal Play

The Gidgealpa Group is characterised by coal measures, especially in the Patchawarra, Epsilon and Toolachee formations. Thick, laterally extensive coal seams have been intersected in both the Patchawarra Formation and the Toolachee Formation. The base Patchawarra Formation maturity map shows that the Patchawarra Formation is sufficiently mature for the generation of gas from coal seams over much of the basin.

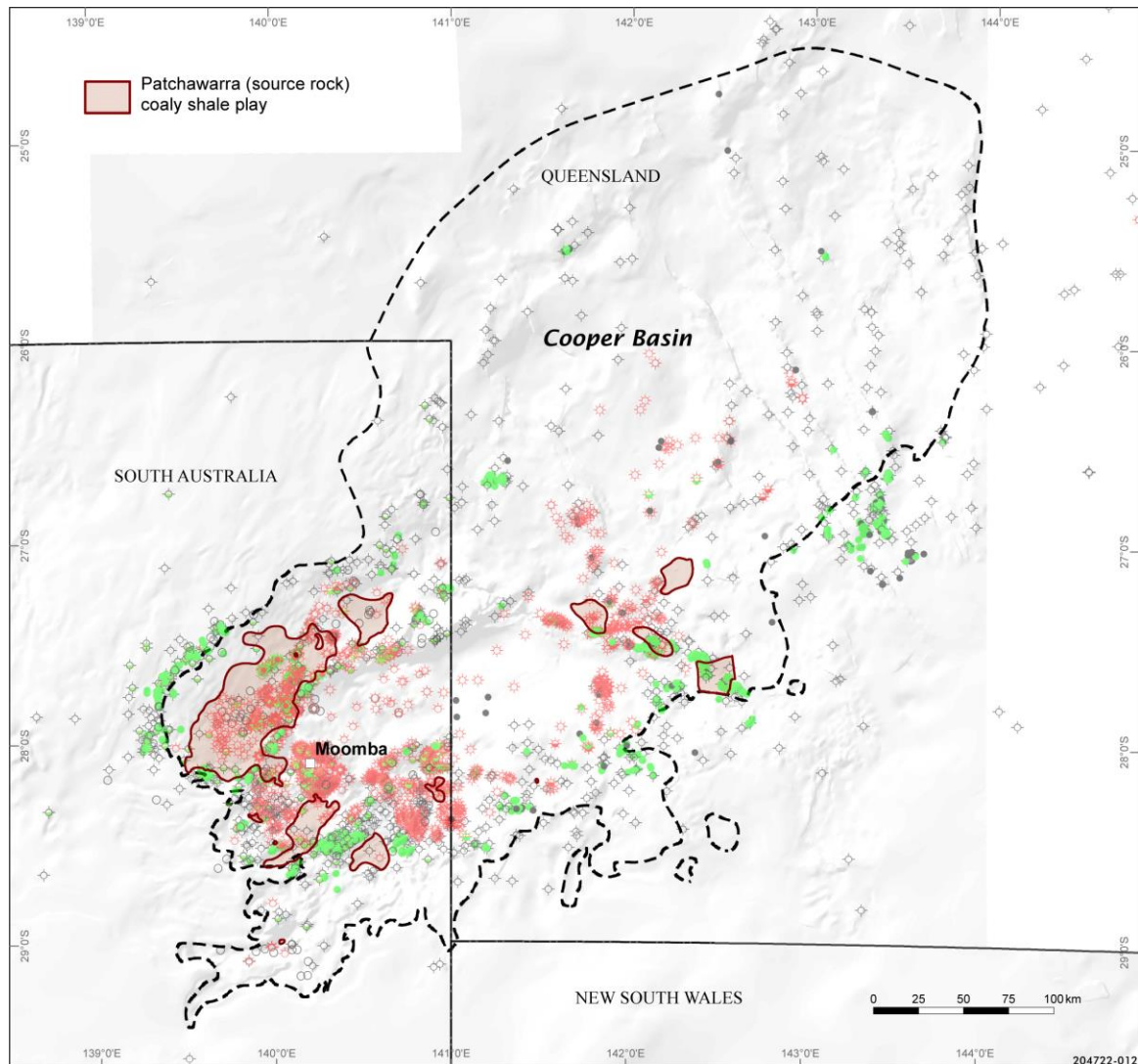
Figure 4.9 Cooper | Permian (source rock) coal play (courtesy of DSD-ERD, 2016)



#### 4.5.7 Patchawarra (source rock) Coaly Shale Play

In addition, laterally and vertically extensive coaly shales within the base Patchawarra appears to be a liquids rich source that will make the economics of commercialization more attractive, but is relatively untested..

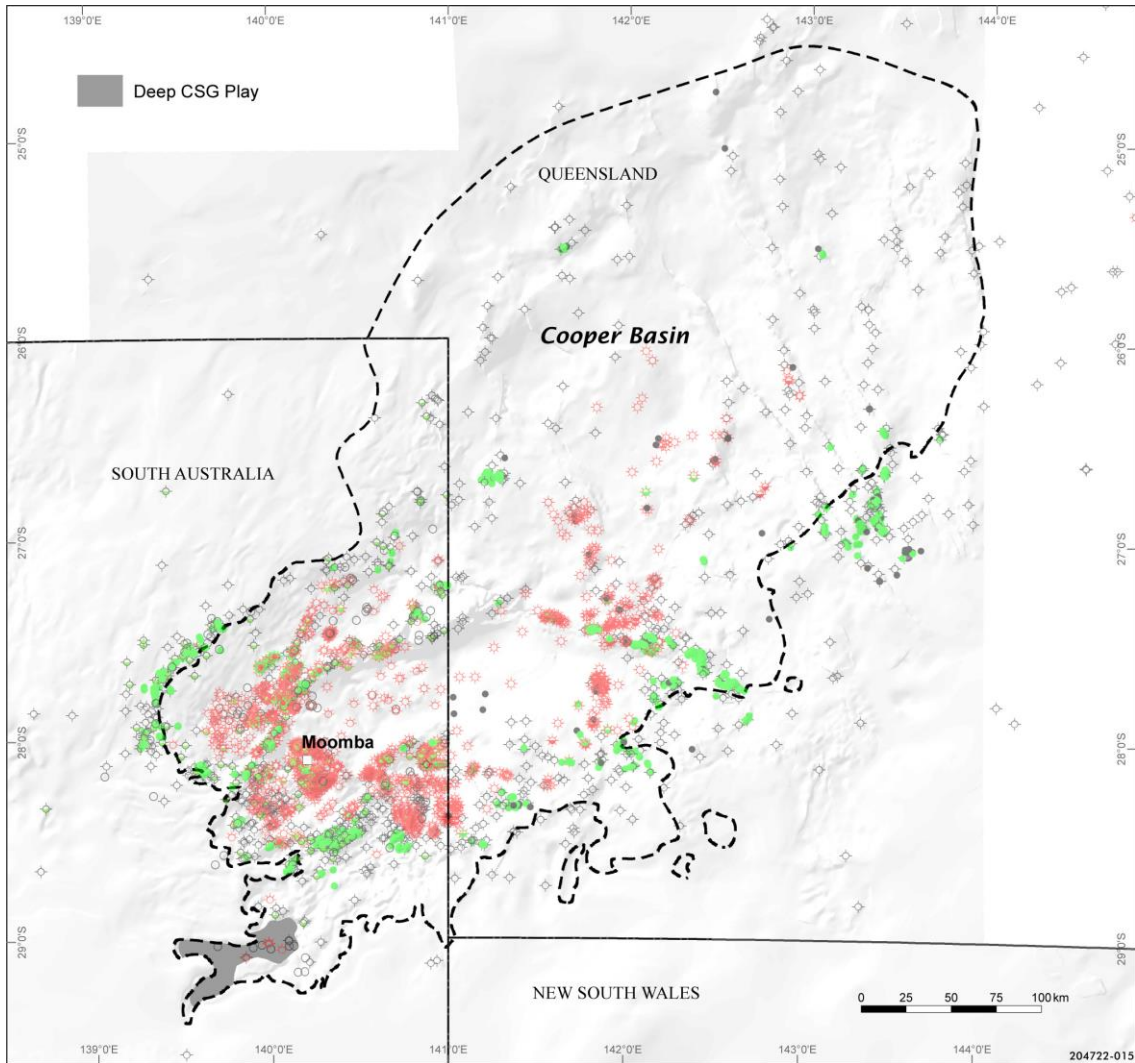
Figure 4.10 Cooper | Patchawarra (source rock) coaly shale play (courtesy of DSD-ERD, 2016)



#### 4.5.8 Deep Coal Seam Gas (CSG) Play

A deep CSG play has been identified within the Weena Trough in South Australia where thick coals of the Patchawarra Formation are being evaluated by long term production testing.

Figure 4.11 Cooper | Deep CSG Play



## 5. Risk Assessment

In order to identify the key focus areas for this study, Core facilitated a series of workshops involving the Core project team and DSD-ERD executives, together with desktop analysis. A risk management framework was utilised in accordance with the international standards.

### 5.1 Risk Matrix

Core has used a Likelihood/Consequences framework to identify all risks which are rated as high to very high.

Likelihood Rating	Almost Certain	Low	Medium	High	Very High	Very High
	Likely	Low	Medium	High	High	Very High
	Possible	Very Low	Low	Medium	High	High
	Unlikely	Very Low	Very Low	Low	Medium	High
	Remote	Very Low	Very Low	Low	Medium	Medium
		I	II	III	IV	V
		Consequences				

The following has been identified as key commercial risk for the purpose of this review:

- The potential for Cooper Basin targeted production to be displaced by a lower cost source/s to the extent that future gas production becomes unviable, with follow on impact on the economics of oil development and production.

The consequence is assessed as high. The likelihood is unlikely to possible.

## 6. Gas Demand and Supply Outlook

### 6.1 Introduction

This section of the study analyses the outlook for gas demand and supply associated with both domestic and LNG markets, as a basis for defining the likely market available to the Cooper Basin, having regard to:

- Existing contracted positions; and
- Likely Eastern Australian demand and supply scenarios, and resulting unfulfilled demand under each scenario.

### 6.2 Likely Cooper Basin Market

Core has derived a likely contestable market for Cooper Basin supply, comprising three tiers:

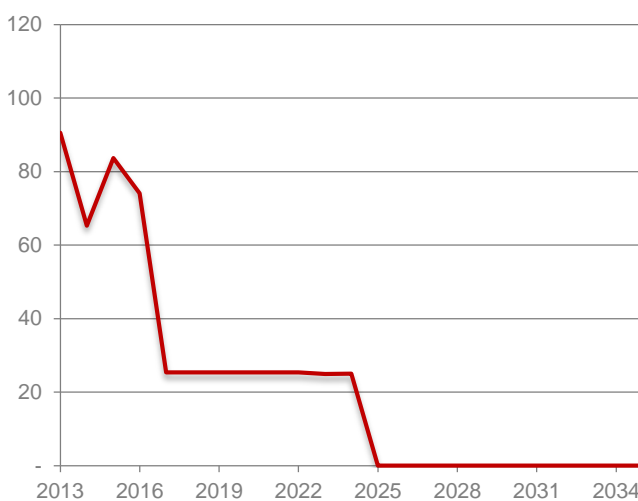
- Tier 1 – Existing domestic contracts, primarily with AGL and Origin to 2016 and Origin alone from 2017 (see Figure 6.1).
- Tier 2 – Santos Horizon contract targeting 750PJ of production from Cooper Basin over 15 years (see Figure 6.2). It is important to note that Santos is likely to have the ability to source this gas from alternative supply areas.
- Tier 3 – Additional supply beyond Horizon to meet LNG supply shortfall and unfulfilled domestic demand.

A summary of the key findings of this study are presented below, while more detailed analysis is included in Attachment A.2.

#### 6.2.1 Tier 1 | Existing Domestic Contracts

The following figure presents total existing CBJV domestic contracts (SACB JV and SWQ Unit). The period to 2017 includes a significant contract with AGL, together with other industrial contracts. Beyond 2017 the only contract is a gas sale arrangement between Beach and Origin (17 PJ). Origin also holds equity share of projected gas production of approximately 8 PJ beyond 2017.

Figure 6.1 Total Cooper Basin Domestic Contracts | PJ

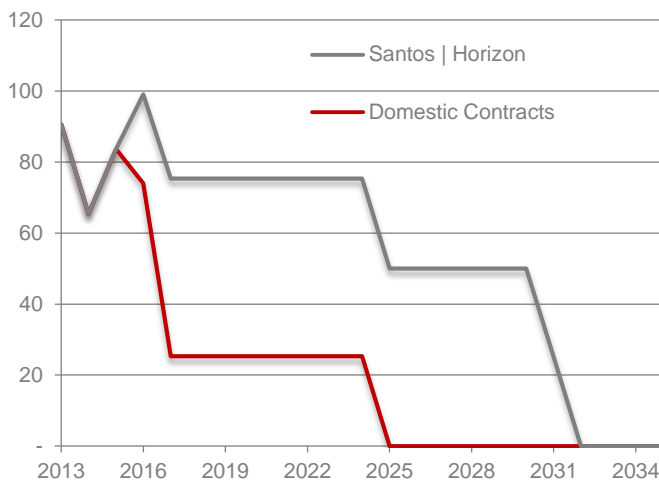


### 6.2.2 Existing LNG Contracts

Santos has entered into a contract, known as the Horizon contract, with GLNG to supply 750 PJ over 15 years. Santos has noted that this will be produced from the Cooper Basin, however Core is uncertain as to the degree of flexibility to access supply from alternative sources. Core notes that it would be commercially logical to allow supply from other sources to fulfil the Horizon contract, in addition to the Cooper Basin (such as Qld CSG).

The following figure presents the Horizon contract volumes of ~50 PJ p.a., in addition to the domestic tier previously mentioned. Total contracted volumes of sales gas is approximately 75 PJ p.a. to 2024. Domestic contracts of approximately 25 PJ p.a. mature in 2024.

**Figure 6.2 Existing Cooper Basin Domestic and LNG Contracts | PJ**



### 6.2.3 Additional Cooper Basin Potential

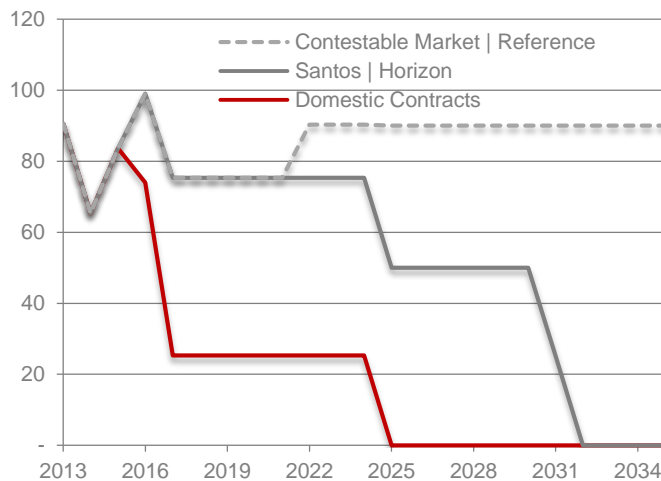
Core has undertaken an analysis of projected demand and supply for both domestic and LNG markets, to derive a contestable market available to the Cooper Basin to 2035. This analysis assumes that field performance potential as reported by operators of competitive supply regions actually materialises. Any material underperformance of competing fields could expand the market available to the Cooper Basin and vice versa.

Core considers that it is reasonable to target a future annual gas production volume of up to approximately 80-90 PJ p.a. (South Australia and South West Queensland combined), as presented in the following figure, with a balance between risk to the upside and downside.

Core has also developed a Higher Scenario which assumes a higher (albeit conservative) development of resources at a cost which is competitive with supply alternatives, particularly higher cost (per GJ) Queensland CSG. This scenario indicates that the Cooper can supply a further 30 PJ p.a. under a lower cost scenario. Given the multi-TCF potential of several unconventional plays in the Cooper Basin, there are prospects for converting resources to reserves to meet greater market demand for gas. Development could lead to significantly higher production to meet future domestic and LNG demand beyond existing contract periods.

For the Cooper Basin to reach the contestable market Reference or High Scenario there has to be a greater level of reserve development and investment in unconventional plays.

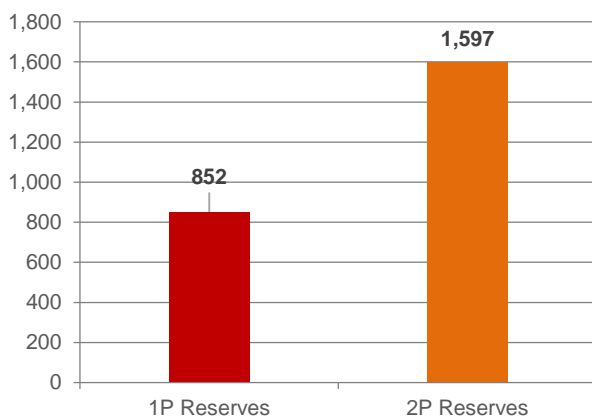


**Figure 6.3 | Cooper Domestic, Santos Horizon and Contestable Market | PJ**

## 6.3 Gas Supply

### 6.3.1 Gas Reserves and Resources

The total 2P reserves booked across the Cooper Basin as at 30 June 2015 are summarised in the figure below, together with an allocation of 2P reserves by the South Australian and South West Queensland Cooper Basin joint ventures. This analysis does not yet reflect Santos' (February 2016) 38 mmboe reduction in Cooper Basin reserves due mainly to lower oil price assumptions and work program results.<sup>18</sup>

**Figure 6.4 Total Cooper Basin Reserves | PJ**

Approximately 1,400 PJ of these reserves are booked within the SACB JV and the remainder within the SWQ Unit as summarised in the following figures.

<sup>18</sup> For more details – see: [https://www.santos.com/media/3206/160219\\_reserves\\_statement.pdf](https://www.santos.com/media/3206/160219_reserves_statement.pdf)

Figure 6.5 CBJV Gas Reserves | PJ

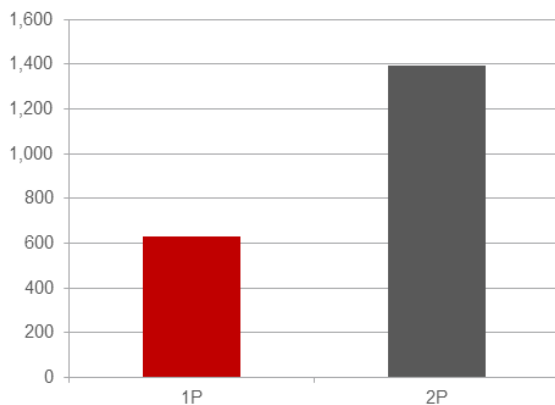
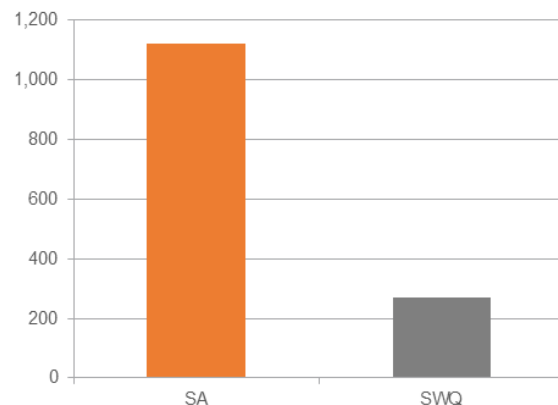


Figure 6.6 CBJV 2P Gas Reserves | PJ



It should be noted that Santos, as operator of the Cooper Basin joint ventures lowered its estimate of reserves by 25% from 972PJ to 726PJ which reduces 2P reserves for the CBJV to approximately 1050PJ.<sup>19</sup> Revisions primarily came from work program results and project updates in the Baryulah, Coonatie, Tirrawarra-Gooranie, Big Lake and Moomba fields.

### 6.3.2 Gas Production

Core has developed a scenario of gas production from existing development wells for the SACB JV and SWQ Unit, utilising Government sourced data and specialist modelling software.

#### 6.3.2.1 South Australia | Existing Development Wells

Core has developed a decline curve for all existing South Australian wells, utilising open-file data provided by DSD-ERD. Core used internationally recognised modelling software to develop decline curves based on over a decade of production history. Well locations are summarised in Figure 6.8 and the production projection summarised in Figure 6.7.

The cumulative production to 2035 presented in Figure 6.7 below is 661 PJ, which shows that a significant portion of the booked SACB JV reserves as at 30 June 2015, and summarised above, are produced over a long tail. This is at risk if operating costs are not constrained and grow materially on a per unit basis. Incremental reserves growth from unconventional plays is one factor that poses a realistic chance of mitigating this risk being realised.

Results have been peer reviewed and compared against reserves reported by field operators to ensure reasonableness.

<sup>19</sup> [https://www.santos.com/media/3206/160219\\_reserves\\_statement.pdf](https://www.santos.com/media/3206/160219_reserves_statement.pdf)



Figure 6.7 Projected Total SA Production | PJ

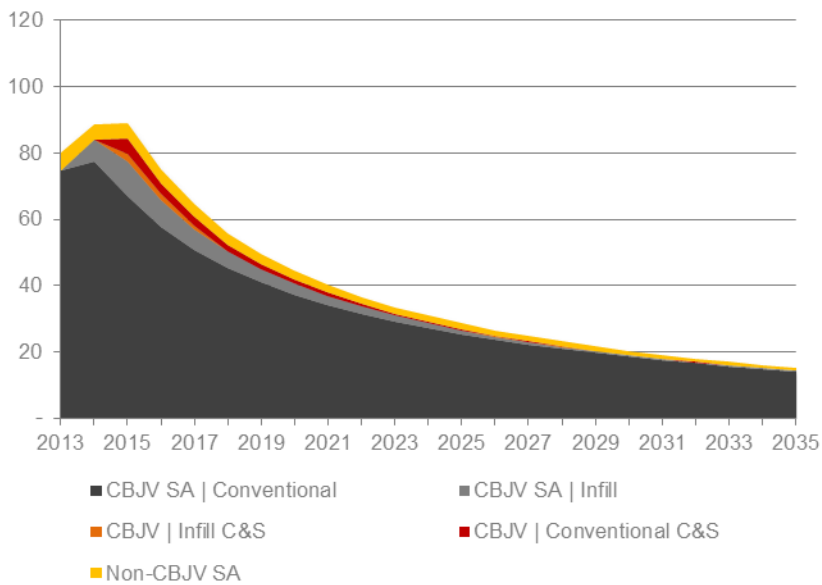
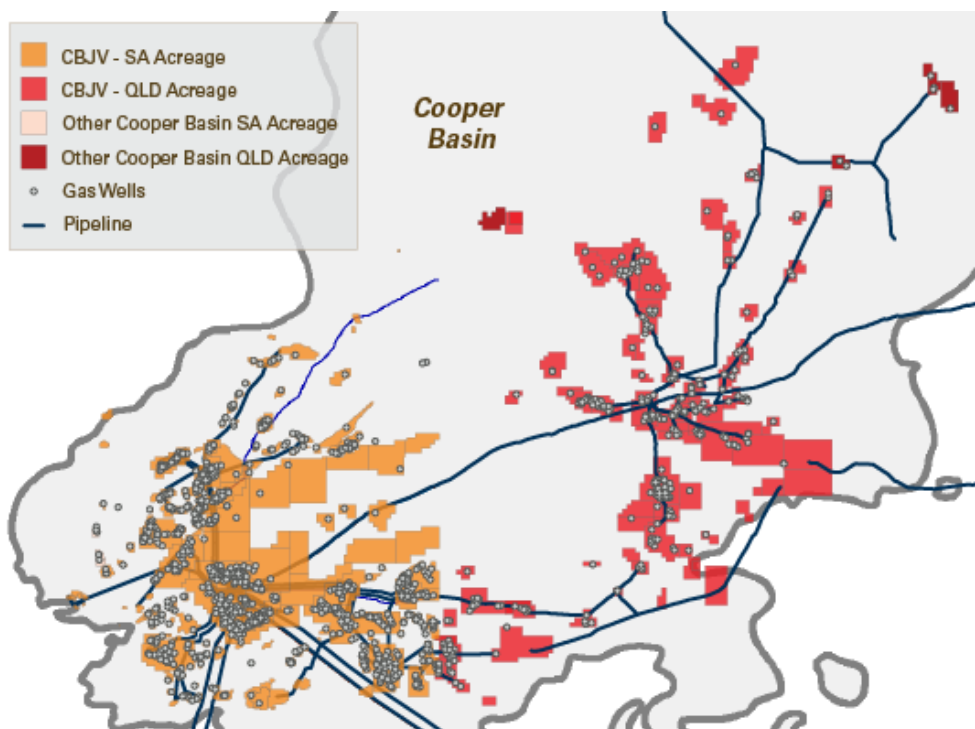


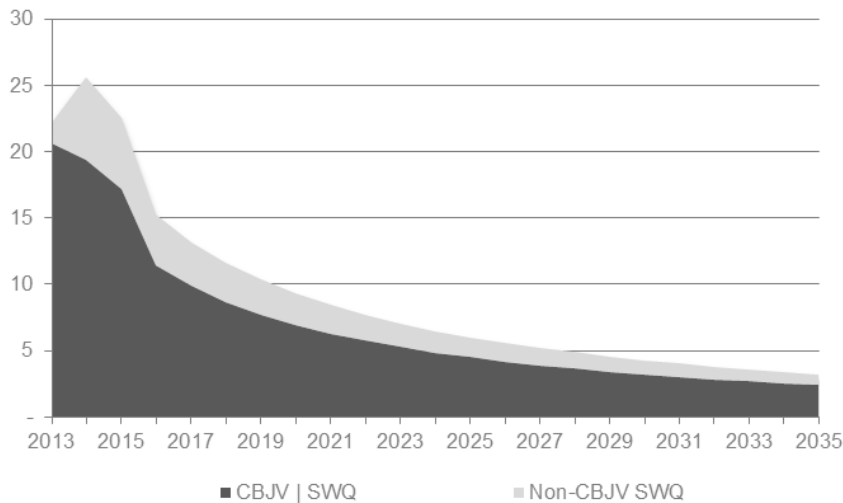
Figure 6.8 Gas Development Well Location Map – South Australia &amp; South West Queensland



### 6.3.2.2 South West Queensland | Existing Development Wells

Core has developed a projection of South West Queensland gas production in a manner consistent with the approach for South Australia, utilising open-file information disclosed by Queensland Government. Well locations are summarised in Figure 6.8. The cumulative production to 2035 presented in Figure 6.9 below is 138 PJ, which is broadly in line with South West Queensland reserves as at 30 June 2015 and as summarised above. Results were peer reviewed and compared against reserves reported by field operators to ensure reasonableness.

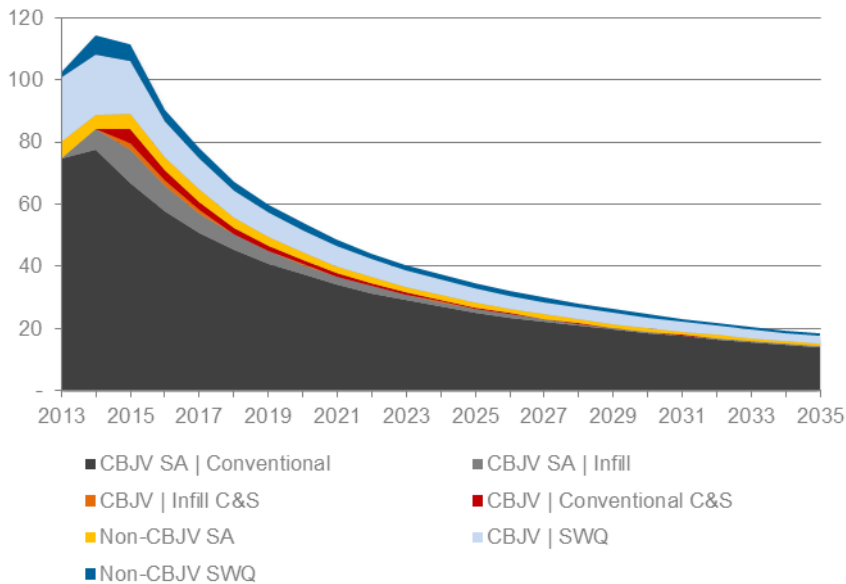
**Figure 6.9 Projected Total South West Queensland Production | PJ**



### 6.3.2.3 Combined South Australia and South West Queensland | Existing Development Wells | PJ

Adding the South Australian and South West Queensland production together provides a total Cooper Basin production estimate as presented in Figure 6.10.

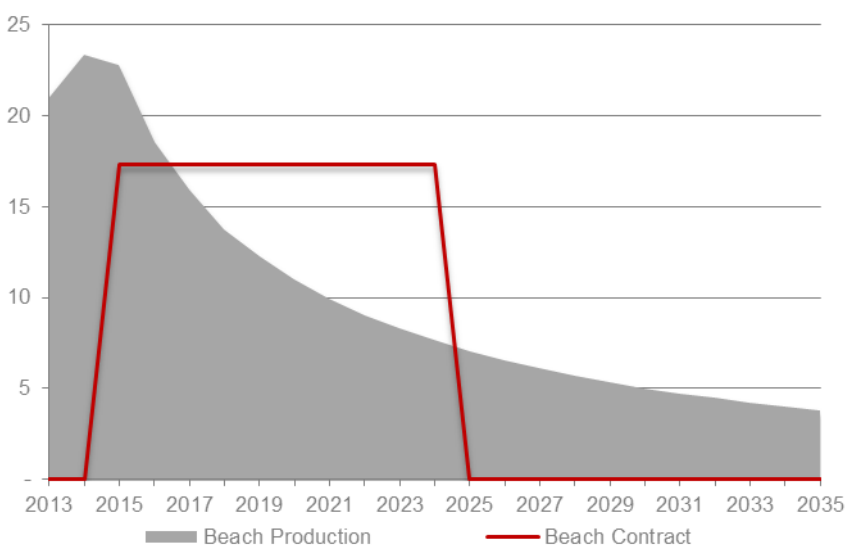
Figure 6.10 Projected Total Cooper Basin Production | PJ



### 6.3.3 Beach Domestic Contract with Origin

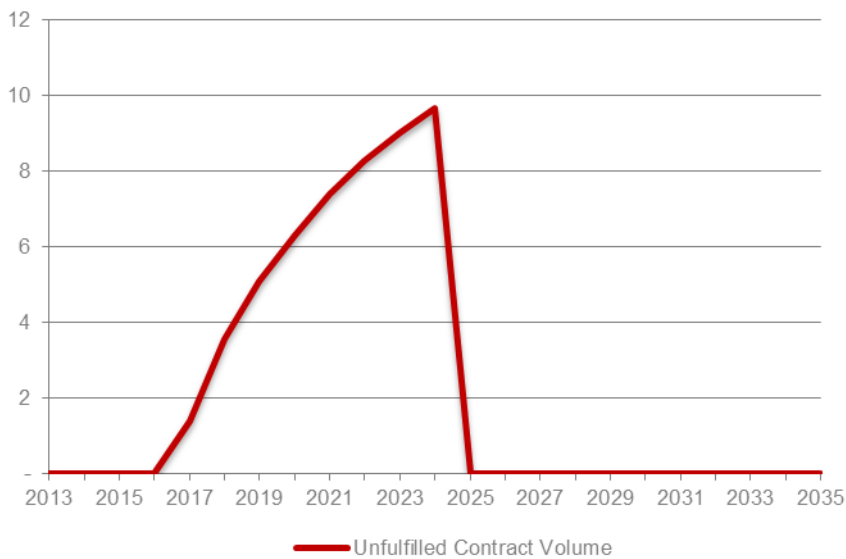
Beach has entered into a separate Cooper Basin supply contract with Origin. Therefore, Core has determined the Beach equity share of Cooper Basin production (~20%) relative to the Beach/Origin domestic contract. This analysis is summarised in the following figure.

Figure 6.11 Beach Cooper Basin Production and Origin Domestic Contract | PJ



The gap between the contract and the base production is presented in Figure 6.12.

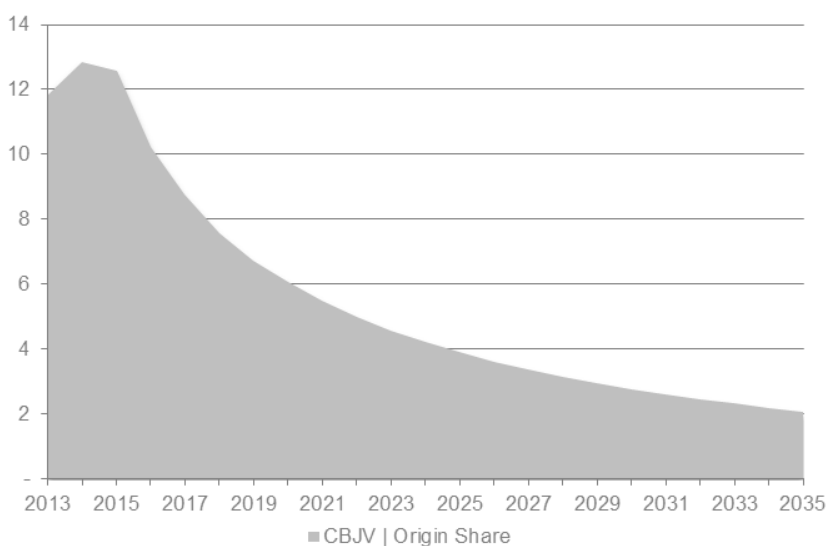
**Figure 6.12 Beach Contract Supply Gap | PJ**



#### 6.3.4 Origin Share of Total Cooper Production

Origin has withheld its equity share of Cooper gas from Santos' Horizon contract. Core has determined the Origin equity share of Cooper Basin production is approximately 13%. This does not include production from Origin's share in the new potential unconventional plays which could add material production per annum<sup>20</sup>. This analysis is summarised in the following figure.

**Figure 6.13 Origin Equity Share | PJ**



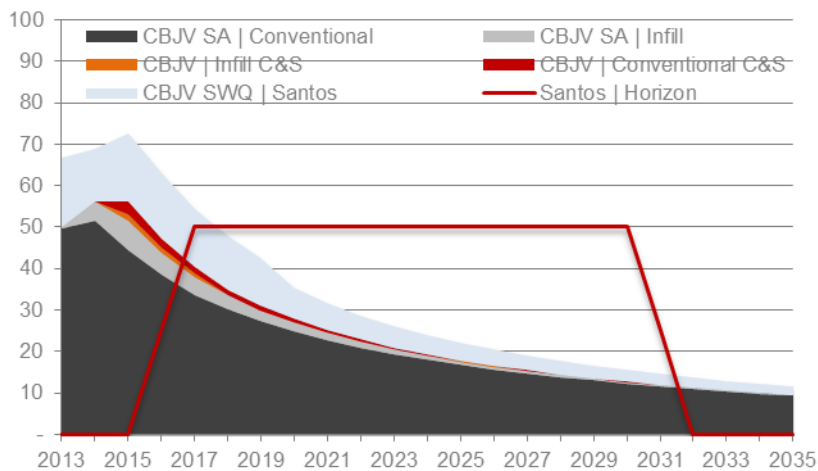
<sup>20</sup> Included in Origin Energy's portfolio of unconventional projects in the Cooper Basin is its farm-in to Senex Energy's areas wherein Efficient-1 and Ethereal-1 wells were drilled (in late 2015-early 2016) to evaluate material gas accumulations in the Allunga Trough and were described by Senex Energy as in line with expectations. For additional details – see: [www.asx.com.au/asxpdf/20160113/pdf/434byrx2x6h8yg.pdf](http://www.asx.com.au/asxpdf/20160113/pdf/434byrx2x6h8yg.pdf)

### 6.3.5 Santos Share of Production as forecast in June 2015

Origin has entered into a separate Cooper Basin supply contract with Beach, and has opted to retain its own equity gas for domestic purposes. As such, Santos will be the only party supplying production volumes from the Cooper Basin to fulfil the Horizon contract.

The following figure summarises Santos' share of projected production relative to the Horizon contract, and its share of remaining legacy domestic contracts (i.e. excluding Beach/Origin contract).

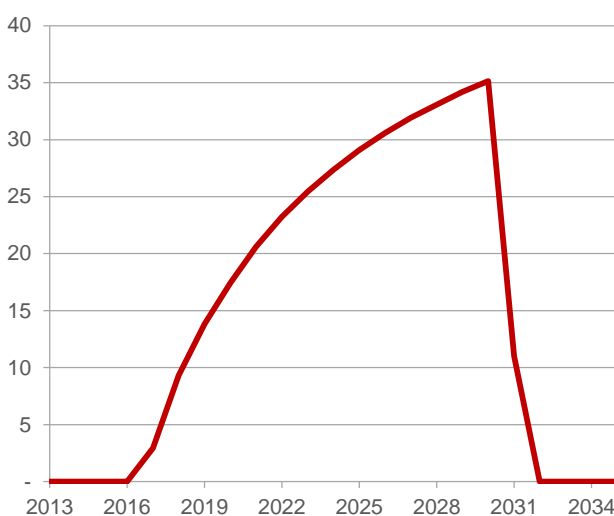
Figure 6.14 Santos' Cooper Basin production from existing wells against Horizon contract | PJ



This figure highlights the fact that significant development activity will be required in the near term in order to ensure contracted volumes during the initial years of the contract are fulfilled. Alternatively, supply could be sourced from other supply areas in lieu of Cooper Basin supply.

The extent of the gap between the Horizon contract and projected supply from existing Santos production is summarised in the following figure.

Figure 6.15 Horizon Contract Supply Gap | PJ



### 6.3.6 Total Supply Gap/Potential

Figure 6.16 shows that from 2017 onward the existing production from the CBJV and Non-CBJV sources will not be sufficient to meet the existing contracts. The gap can prospectively be met with new production from either the infill program and or the unconventional reservoir plays.

Figure 6.16 Existing Production, Contracted Demand and Contestable Market | PJ

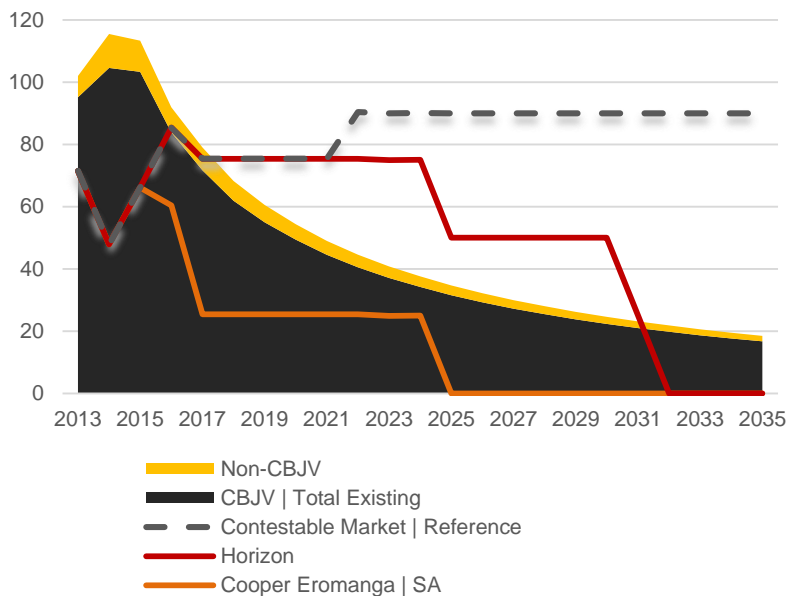


Figure 6.16 presents a summation of the gap between the production projection associated with existing wells and Beach and Santos contract only. This is the total contracted demand less total projected production. This gap represents almost 400 PJ (50 PJ Beach and 350 PJ Horizon).

Figure 6.17 presents the gap between the production projection associated with existing wells and the total contestable market identified by Core. This gap represents approximately 1,000 PJ. (600 PJ incremental to above).

Figure 6.17 Total Forecast Contract Supply Gap | PJ

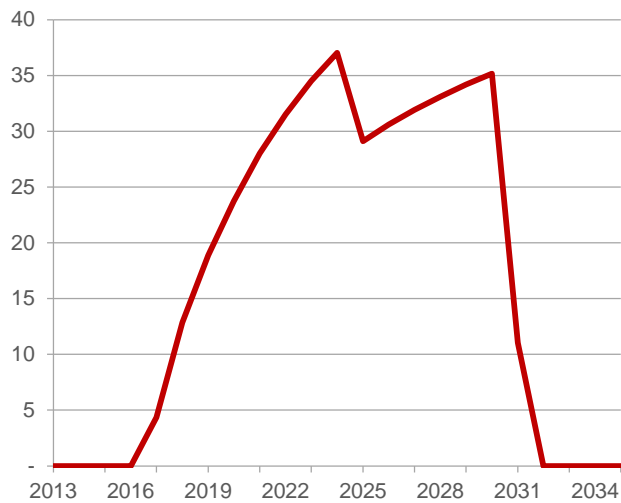


Figure 6.18 Total Forecast Supply Gap (including. contestable market) | PJ



### 6.3.7 Supply Options to Meet the Supply Gap

The infill program and unconventional plays are the two foreseeable options which could potentially increase production to meet the demand gap.

There are several possible ways for the Cooper Basin to meet the supply gap. Efficient unconventional play development appears to be the best chance for the Cooper Basin to maintain its position as a low cost supply area.

#### 6.3.7.1 Wells Required to Meet Supply Gap

Core has derived an estimate of the number and timing of wells required to meet this supply gap based on the following major assumptions:

- Initial production rates – the initial production rate is based on the average monthly mscfe/d rate over the first six months.
- Peak production rate – the peak production rate is derived by taking the average of the average mscfe/d rate for the three highest months of production during the first year.
- Expected Ultimate Recovery (“EUR”) – the total recoverable amount from a well is the sum of past and projected production.
- Decline Rate – this is based on the average annual decline in production from year to year.
- Hyperbolic Exponent – the Arps production decline equation is used to estimate the shape of the decline curve. The decline curve is assumed to be standard hyperbolic.

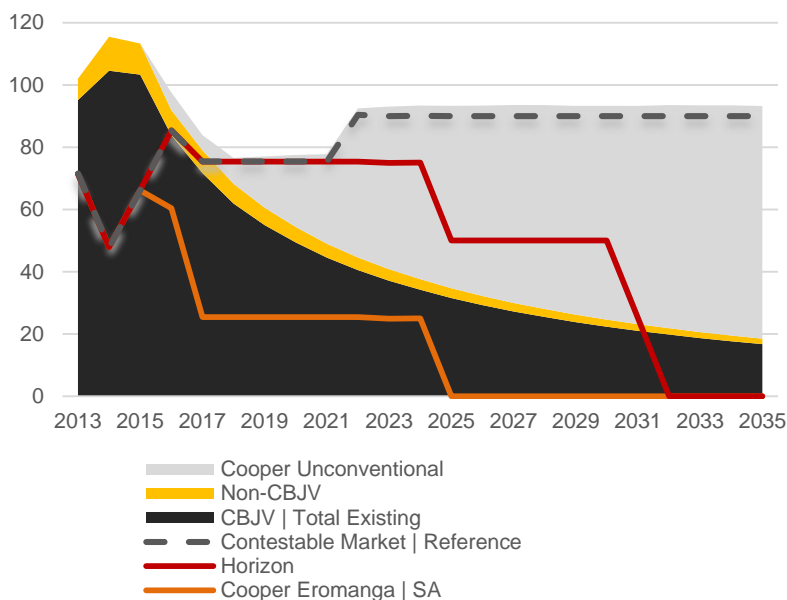
The production target for the infill program assumes that it will meet the existing contract shortfall. The unconventional plays in the Cooper Basin are assumed to have a production target based on meeting the existing contracts and the potential contestable market.

**Table 6.1 Key Assumptions driving the number of wells | Reference**

Key Assumption	Units	Wells to produce from Unconventional Plays	Infill Wells
Production Target	PJ	1176	494
Investment	\$	2.6 billion (~600 wells)	1.5 billion (~400 wells)
Initial Production Rate	Mscfe/d	2327	915
Peak Production Rate	Mscfe/d	2780	1200
Expected Ultimate Recovery	Bcf	3.0	2.1
Decline Rate	% p.a	49%	60%
Hyperbolic Exponent	No.	0.40	0.6
Methane Percentage	%	70%	75%
Well Commercial Failure Rate	%	5%	1%

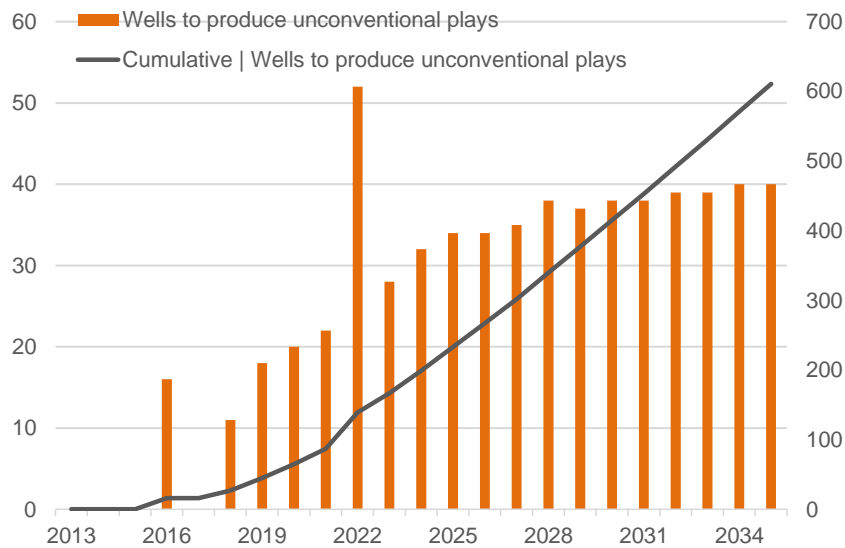
### 6.3.8 Development wells into unconventional plays to meet existing contract demand

Figure 6.19 suggests that if the unconventional plays are to meet the reference contestable market, these unconventional plays must contribute to over half the Cooper Basin production by 2025. By default this assumes that there is no new infill production beyond the existing and case and suspended wells.

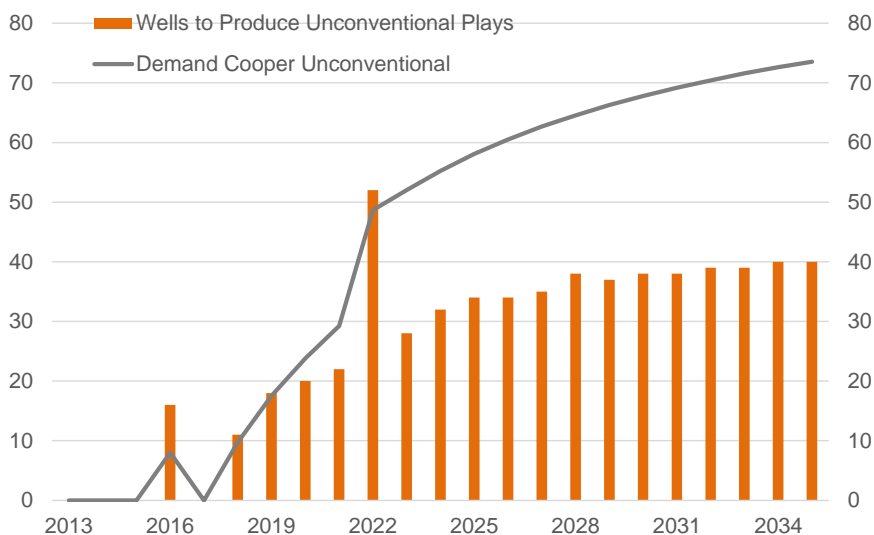
**Figure 6.19 Existing Production, Contracted Demand and Contestable Market | Unconventional Production | PJ**

The resulting number of wells drilled to produce from unconventional plays per annum are summarised in the following figure.



**Figure 6.20 Wells Required to Meet Gap | Annual (LHS); Cumulative (RHS)**

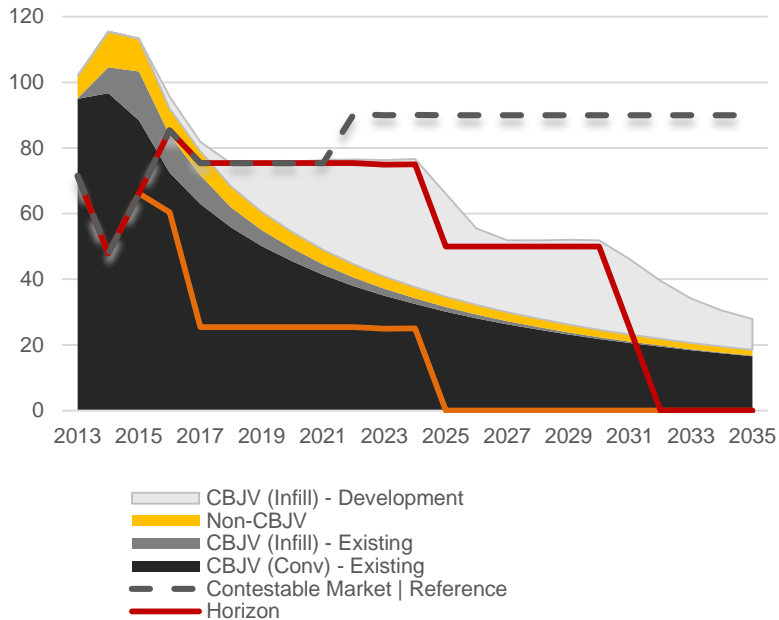
The resulting production profile is summarised in the following figure.

**Figure 6.21 Future Development Required - Annual Wells (RHS); Production (LHS)**

### 6.3.9 Infill wells to meet existing contract demand

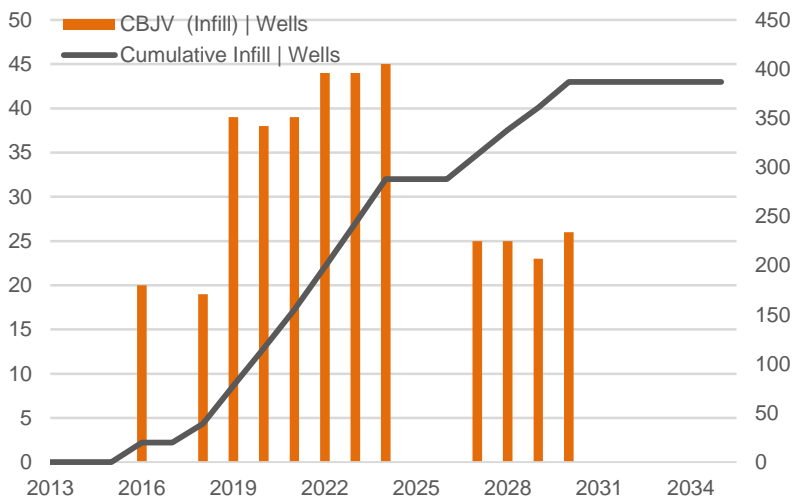
The following diagram shows the infill production meeting the shortfall on existing contracts with the majority being the Horizon Contract.

Figure 6.22 Existing Production, Contracted Demand and Contestable Market | Infill Production | PJ



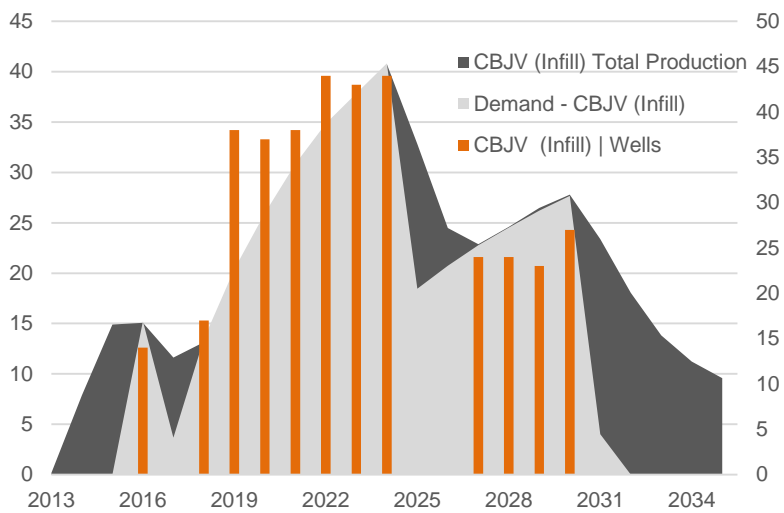
The resulting number of infill wells per annum are summarised in the following figure.

Figure 6.23 Wells Required to Meet Gap | Annual (LHS); Cumulative (RHS)



The resulting production profile is summarised in the following figure.

**Figure 6.24 Future Development Required - Annual Wells (RHS); Production (LHS)**



## 7. Cooper Basin Cost Analysis

### 7.1 Summary

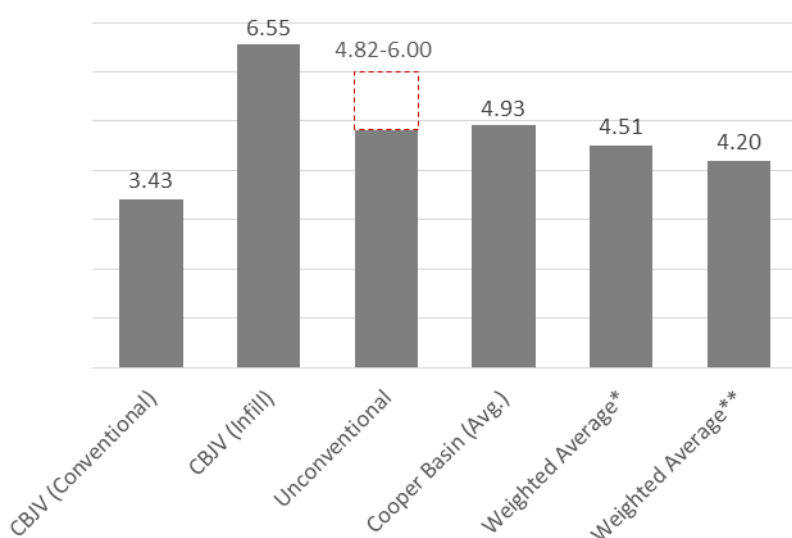
The following figure summarises Core's estimate of the marginal cost of Cooper Basin gas production – with the vast majority associated with the SACB JV.

Three cost measures are considered:

- CBJV (Conv) – marginal cost (largely opex) for existing development wells
- CBJV (Infill) – marginal cost of proposed infill program (well plus opex)
- Cooper Unconventional Plays (well plus opex)
- Weighted average\* - CBJV Conventional and the CBJV Infill Project
- Weighted average\*\* - CBJV Conventional and the Unconventional Source Rock Play

Unconventional gas is estimated to be AUD 4.82/GJ based on global best practice. In reality this could be closer to AUD 6.00/GJ.

Figure 7.1 Marginal cost of production | AUD/GJ<sup>21</sup>



This estimate is presented in further detail in Table 7.1 and Figure 7.2.

Table 7.1 Summary of Marginal Cost Breakdown AUD/GJ | Reference

Cost Driver	Conventional	Infill Program	Unconventional	Weighted Average*	Weighted Average**
Operating Costs	1.27	2.22	2.42	2.01	2.19
Capital Costs	1.89	3.44	1.83	2.03	21.58
Royalty	0.17	0.45	0.31	0.27	0.25
Tax	0.10	0.44	0.26	0.21	0.19
<b>Marginal Cost   AUD/GJ</b>	<b>3.43</b>	<b>6.55</b>	<b>4.82</b>	<b>4.51</b>	<b>4.20</b>

<sup>21</sup> Please note this includes the cost of capital, assumed to be 10%;

Figure 7.2 Marginal Cost Breakdown | AUD/GJ

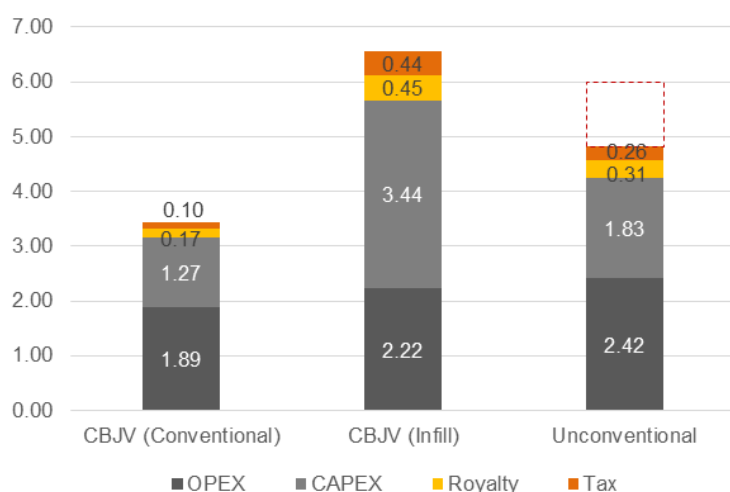


Table 7.2 Unconventional Play Cost Range | Marginal Cost Breakdown | AUD/GJ

Cost Driver	Low	Reference	High
Operating Costs	2.18	2.42	2.73
Capital Costs	1.38	1.83	2.57
Royalty	0.26	0.31	0.40
Tax	0.18	0.26	0.38
<b>Marginal Cost   AUD/GJ</b>	<b>3.99</b>	<b>4.82</b>	<b>6.07</b>

Table 7.3 Infill Program Cost Range | Marginal Cost Breakdown | AUD/GJ

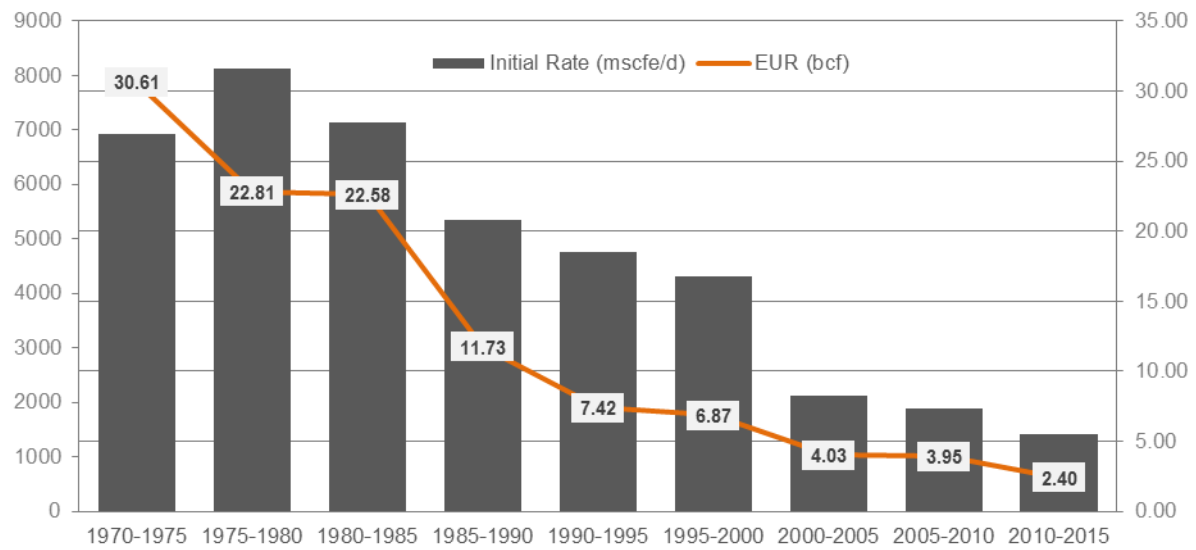
Cost Driver	Low	Reference	High
Operating Costs	1.96	2.22	2.34
Capital Costs	2.59	3.44	4.04
Royalty	0.35	0.45	0.51
Tax	0.27	0.44	0.49
<b>Marginal Cost   AUD/GJ</b>	<b>5.17</b>	<b>6.55</b>	<b>7.39</b>

## 7.2 Cost Drivers

The primary cost drivers impacting the economics of the Cooper Basin, relative to alternative supply sources, are well productivity and operating cost per unit of supply. Secondary drivers include drilling and completion costs, and declining liquid yields. These drivers are addressed in the following paragraphs:

### 7.2.1 Well Productivity

Figure 7.3 highlights the declining trend in well productivity over time, in terms of EUR/well and initial rate of production per well.

**Figure 7.3 Cooper-Eromanga | Initial Rates (LHS) EUR (RHS)**

The gas type well curves in Figure 7.4 and Figure 7.5 display the mscfe/d rates for each half year period for 30 years. The raw gas and composition of methane, ethane, propane and heavy hydrocarbons are also displayed.

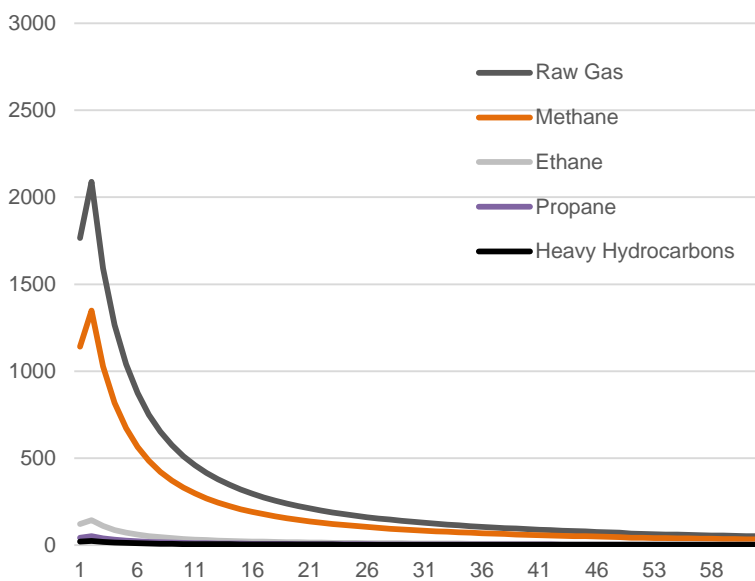
**Figure 7.4 Gas Well Type | Conventional Gas Well - mscfe/d**

Figure 7.5 Gas Well Type | Infill Gas Well - mscfe/d

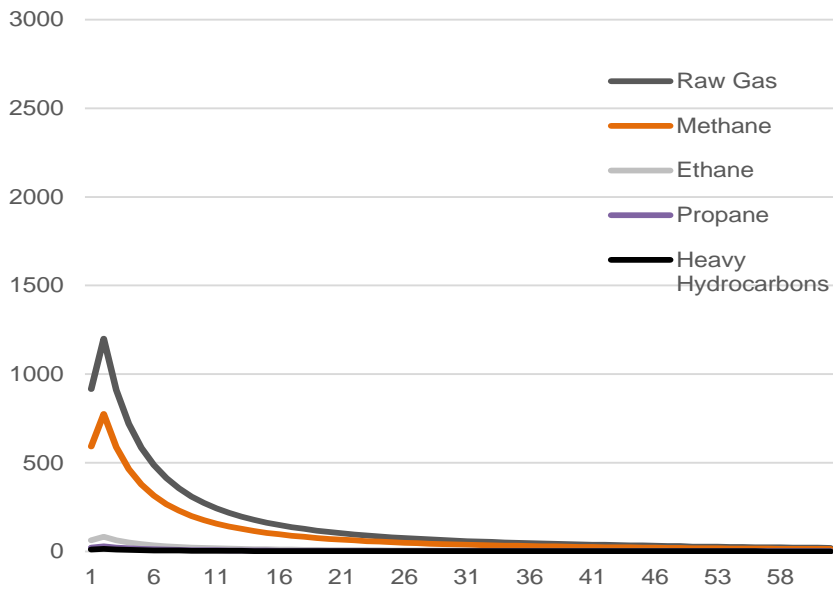
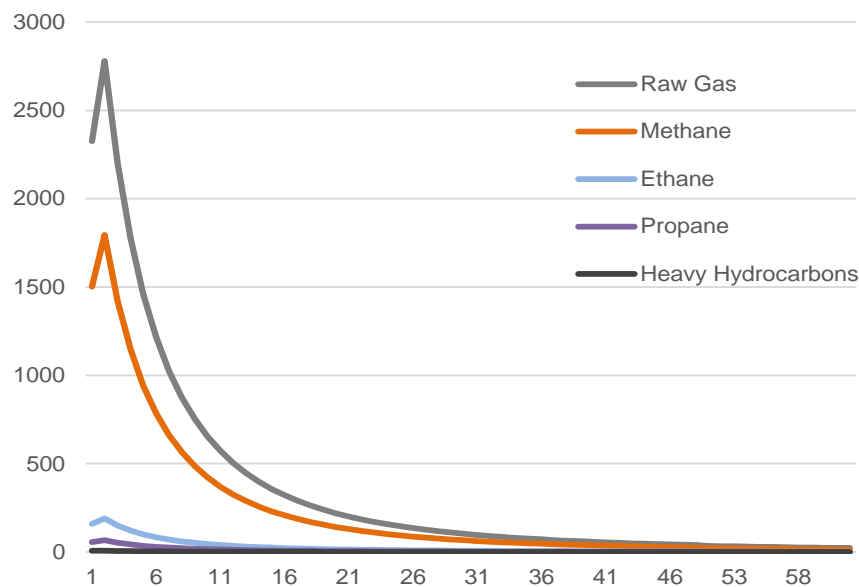
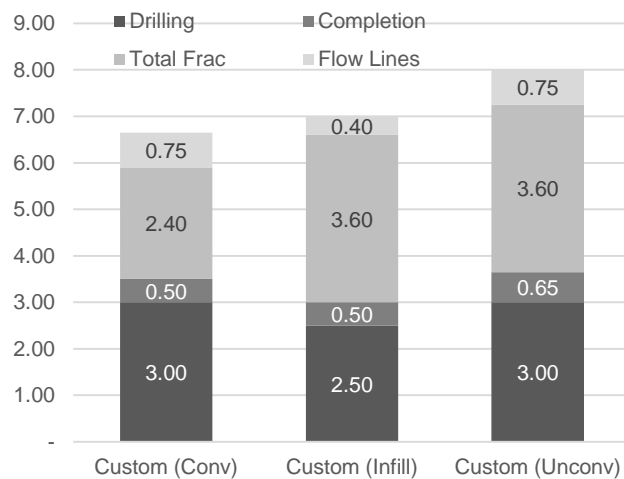


Figure 7.6 Gas Type Well | Median Unconventional Well – mscfe/d



#### 7.2.1.1 Well Cost (as at June 2015)

The average conventional infill well with 6 stages of fracture stimulation is assumed to cost AUD 7M (as at 1 July 2015). The average conventional well is assumed to cost AUD\$6.65M and a well to produce from unconventional plays, AUD 8M. The difference is based on lower flow line and tie costs, as well as efficiencies due to an existing knowledge of area.

**Figure 7.7 Well Costs | AUDM per well<sup>22</sup>**

### 7.2.1.2 Operating Cost

Operating cost is the majority of the cost of existing development well production, and close to 30% of the cost of marginal gas production. It will be important for per unit costs to be maintained at existing levels, and preferably reduced, to ensure Cooper Basin gas remains competitive. Total operating cost attributable to gas is assumed to be close to be approximately AUD 240M p.a. with approximately AUD 40M p.a. attributable to oil, adjusted for tolls. These cost estimates do not take full account of the actions taken by all Cooper Basin producers (since 1 July 2015) to improve productivity and reduce costs.

<sup>22</sup> Please note the unconventional well cost estimate is based on global best practice.

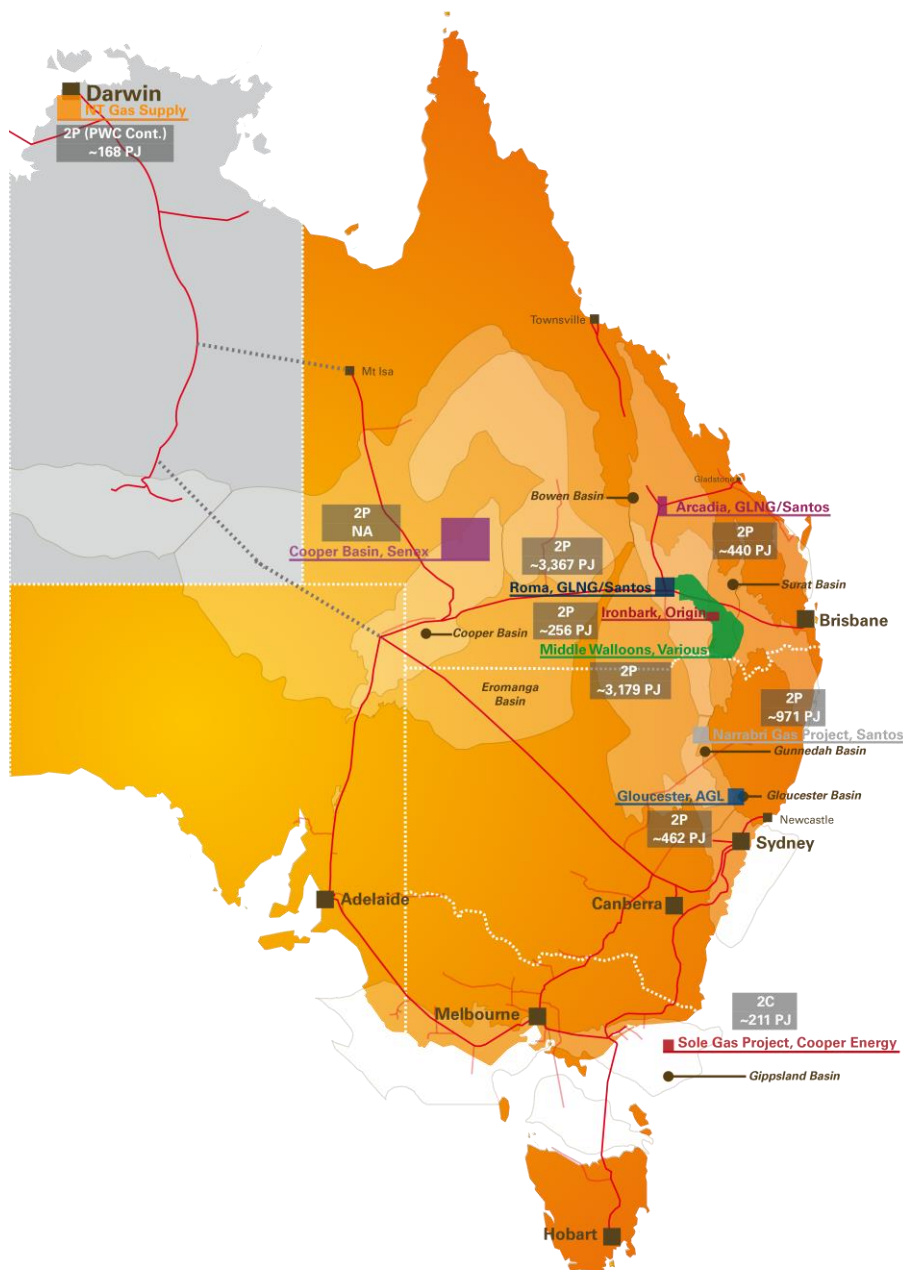


## 8. Competitor Cost Analysis

### 8.1 Summary

Core has identified existing reserves and resources that are available to compete against the Cooper Basin to meet unfulfilled demand. Figure 8.1 summarises these areas and provides an estimate of the existing volume of reserve available to meet unfulfilled demand.

Figure 8.1 Competitive Supply Regions



For each supply area Core has derived an estimate of the cost of supply (marginal cost basis) using the same methodology used to derive the cost of Cooper supply. In analysing cost of supply it is important to differentiate between:

- Production from existing developed wells;
- Production from new wells feeding into existing production facilities; and
- Production from new wells requiring new production facilities.

Each production stream above will have a different marginal cost of supply.

For the purpose of this analysis, Core has focused on resources in the first two cost categories. The results are summarised in the following figures.

Figure 8.2 Supply Regions

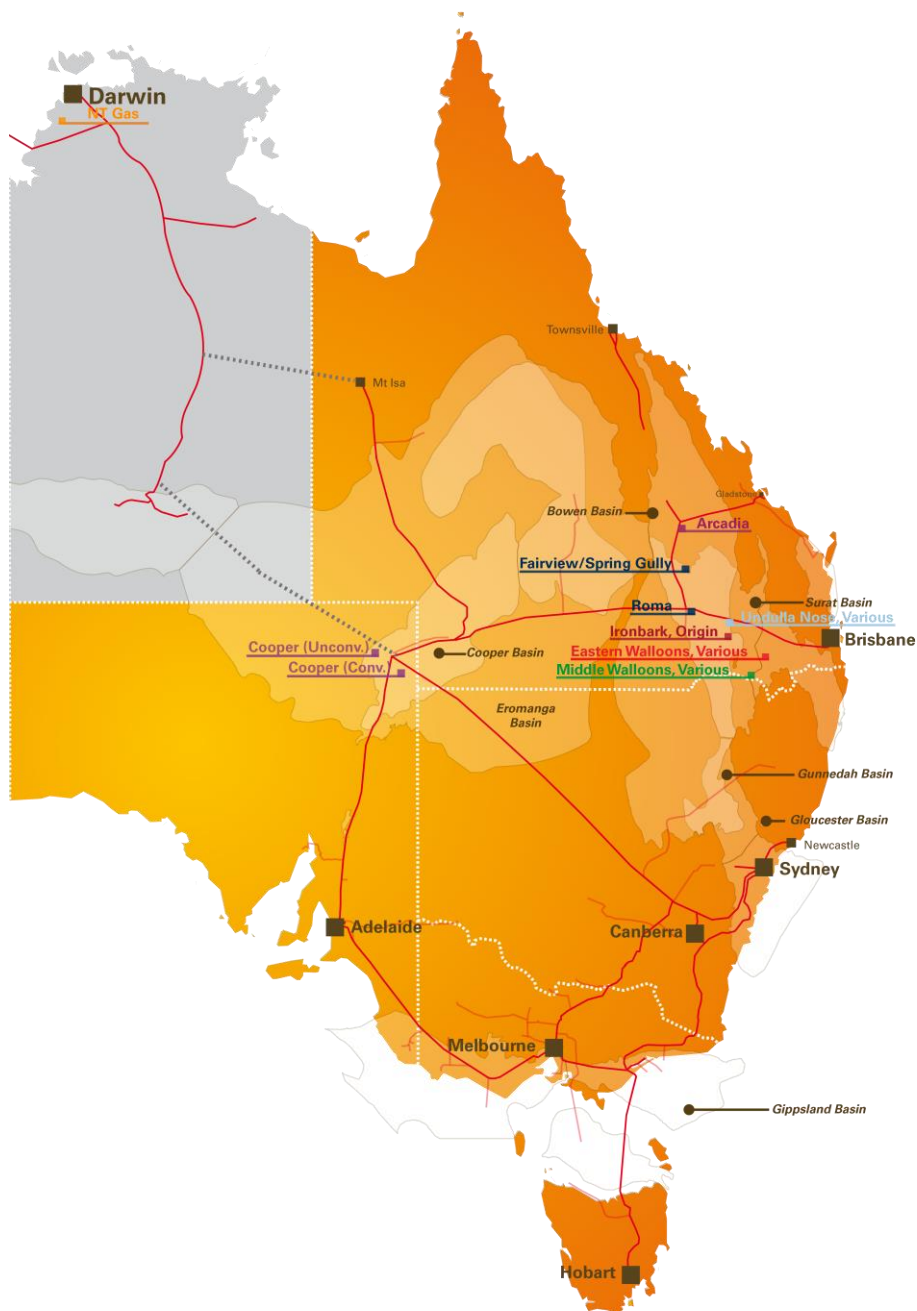
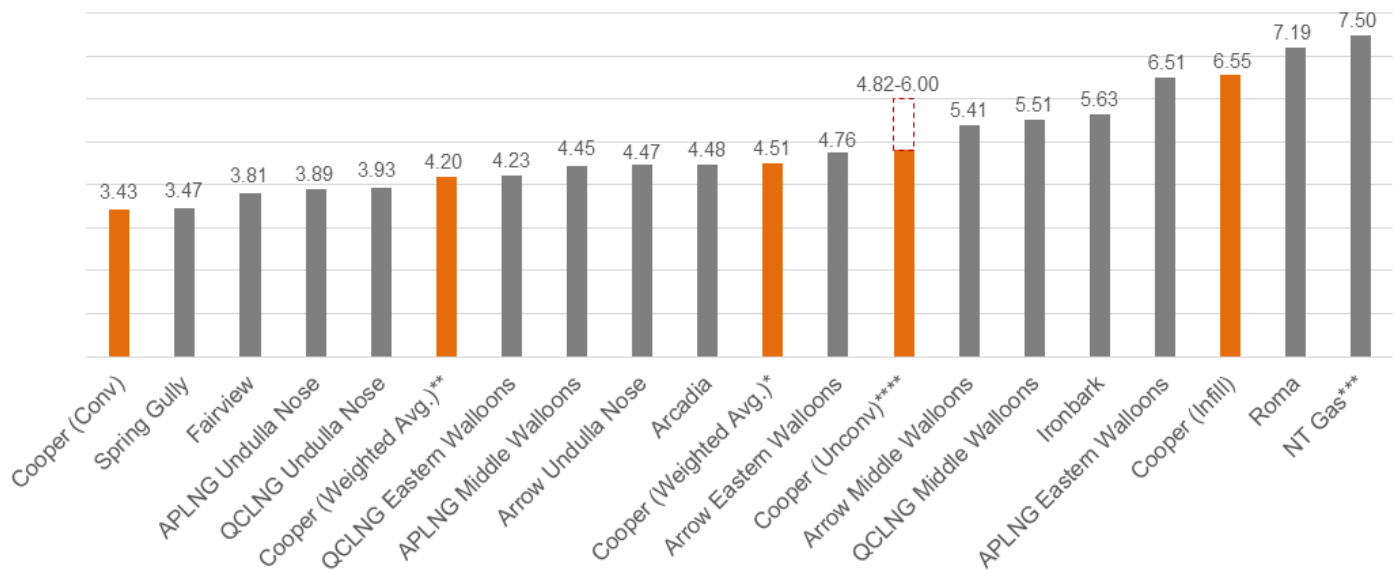


Figure 8.3 Comparison of Cooper Basin and Competitor Marginal Cost of Supply (ex-field) | AUD/GJ



\* Represents the weighted average of the CBJV Conventional gas and the CBJV infill program, under the assumption that infill gas would meet the existing horizon contract shortfall.

\*\* Represents the weighted average of the CBJV Conventional gas and the unconventional source rock play, under the assumption that unconventional gas would meet the existing horizon contract shortfall and the contestable market.

\*\*\* NT Gas is estimated to have a low of AUD6/GJ (Blacktip ex-field) and a high of AUD7.50 (higher cost unconventional plays).

\*\*\*\* Unconventional Cooper supply is estimated to have a cost of AUD4.82/GJ based on global best practice. In reality, this cost could be closer to AUD 6/GJ.

Also note that the type well used for the unconventional plays in the Cooper Basin is the median of five potential well profiles considered. If the most productive well is used the marginal cost could fall to around \$4 per GJ.

Figure 8.4 Competitive Costs | Cooper Basin vs. Queensland CSG | AUD/GJ and PJ Forecast Production

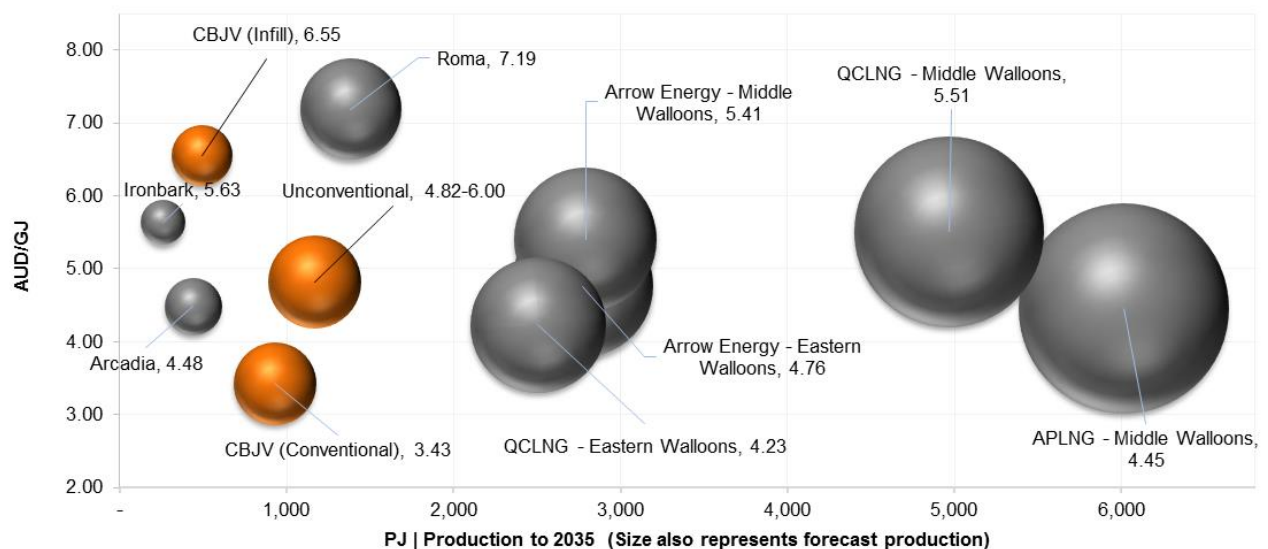
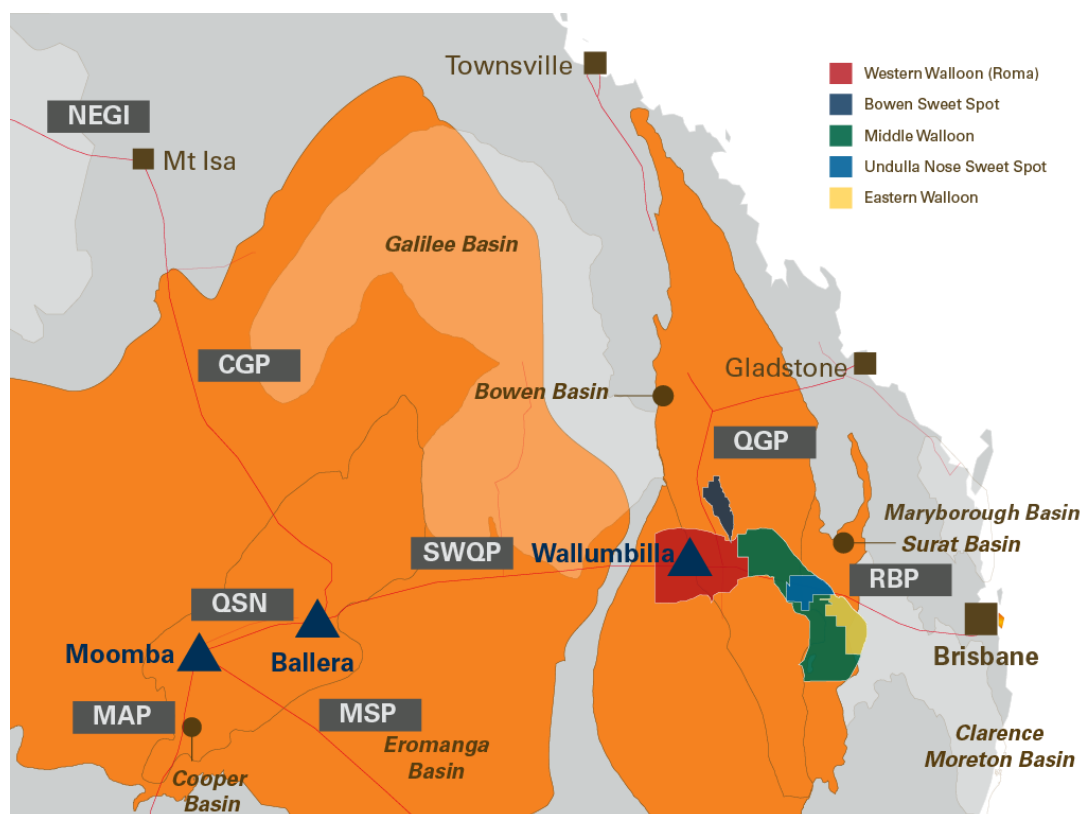


Figure 8.5 Supply Area Location Map



The following tables show the applicable tariffs incurred by these supply sources when delivering gas to Eastern demand points.

- Table 8.1 provides an overview of the relevant indicative transmission tariffs
- Table 8.2 shows the shortest pipeline route and tariff to key markets for each play (these tariffs can be added to ex-gate costs to derive the lowest to highest delivered gas prices)

Table 8.1 Indicative Transmission Tariffs | AUD/GJ

Pipeline	Indicative Tariff	Pipeline Distance (Mainline)   km	AUD cents per km per GJ
MSP	1.00	1,309	0.076
MAP	0.72	859	0.084
RBP	0.68	438	0.155
QGP	0.96	627	0.153
CGP	1.56	840	0.186
SWQP	1.15	755	0.152
QSN	~0.25	182	~0.137
NEGI	~1.55	623	~0.249
NVI	n/a	88	n/a
SEAGAS	0.81	680	0.119
SWP	0.30	144	0.208

**Table 8.2 Indicative Transmission Tariffs for CSG Plays | AUD/GJ**

Gas Play	Market	Pipeline	Indicative Tariff
Western Walloon	Gladstone Domestic	QGP	0.96
	LNG Export   Gladstone	GLNG Pipeline	Pipeline owned by project
	Brisbane	RBP	0.68
Bowen Sweet Spot	Gladstone Domestic	QGP	0.96
	LNG Export   Gladstone	GLNG Pipeline & APLNG Pipeline	Pipelines owned by project
	Brisbane	RBP	0.68
Middle Walloon	Gladstone Domestic	QGP	0.96
	LNG Export   Gladstone	QCLNG Pipeline & APLNG Pipeline	APLNG Pipeline owned by project; QCLNG pipeline owned by APA
	Brisbane	RBP	0.68
Undulla Nose Sweet Spot	Gladstone Domestic	QGP	0.96
	LNG Export   Gladstone	QCLNG Pipeline & APLNG Pipeline	APLNG Pipeline owned by project; QCLNG pipeline owned by APA
	Brisbane	RBP	0.68
Eastern Walloon	Gladstone Domestic	QGP	0.96
	LNG Export   Gladstone	QCLNG Pipeline & APLNG Pipeline	APLNG Pipeline owned by project; QCLNG pipeline owned by APA
	Brisbane	RBP	0.68

This 1 July 2015 analysis (figure 8.3) indicates that the aggregate cost of developing, connecting and processing Cooper gas in conventional reservoirs is quite competitive, Cooper Basin gas in unconventional reservoirs is mid-range competitive, and Cooper Basin gas that can flow from infill drilling is at the higher end of the competitive cost curve. All Cooper Basin gas marginal costs (AUD/GJ) are estimated to be below Roma, a key competitive source which could be used by Santos to meet the Horizon contract volume.

## 8.2 Operating Cost Analysis

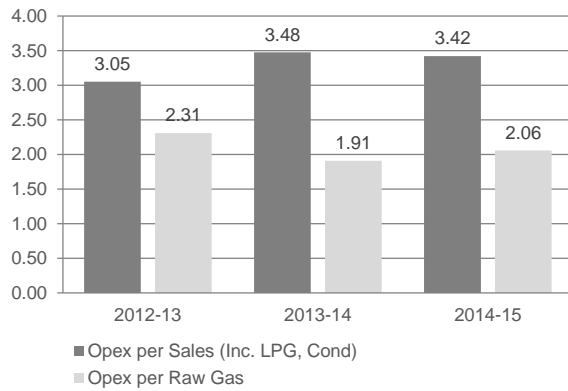
### 8.2.1 Introduction

An analysis of Cooper Basin (SACB JV) operating costs is considered important from the following perspectives:

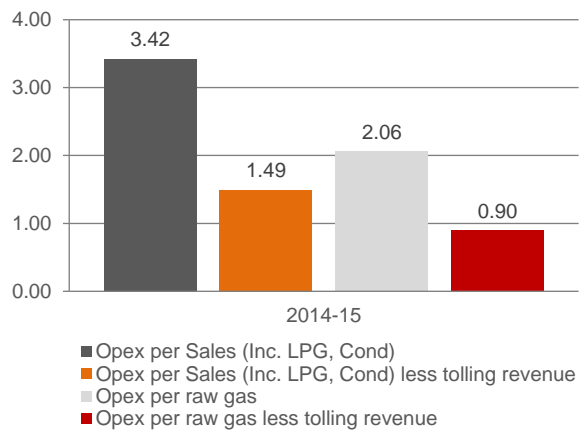
- It is a major component of total cost and it is important to understand the key drivers;
- It is important to understand the relative allocation of operating cost between oil and gas production and how this may vary with time;;
- It is important to develop an understanding of fixed vs. variable components; and
- It is important to understand whether movements in per unit cost could change the competitiveness of Cooper Basin gas production with time, particularly under a scenario where production volumes fall materially.

### 8.2.2 Existing Operating Cost Estimate

In 2014-15 gas operating costs are estimated at approximately AUD 240m or close to AUD3.42/GJ.

**Figure 8.6 CBJV Opex based on Sales and Raw gas Volumes (PEPs) | AUD/GJ**

It is important to note the impact of tolls paid by non-CBJV parties. Core estimates indicate that if all 2014/15 tolls are rebated against gas operating costs, the unit cost for sales gas is closer to AUD1.50/GJ.

**Figure 8.7 OPEX | Tolling Revenue | AUD/GJ**

## 9. Price

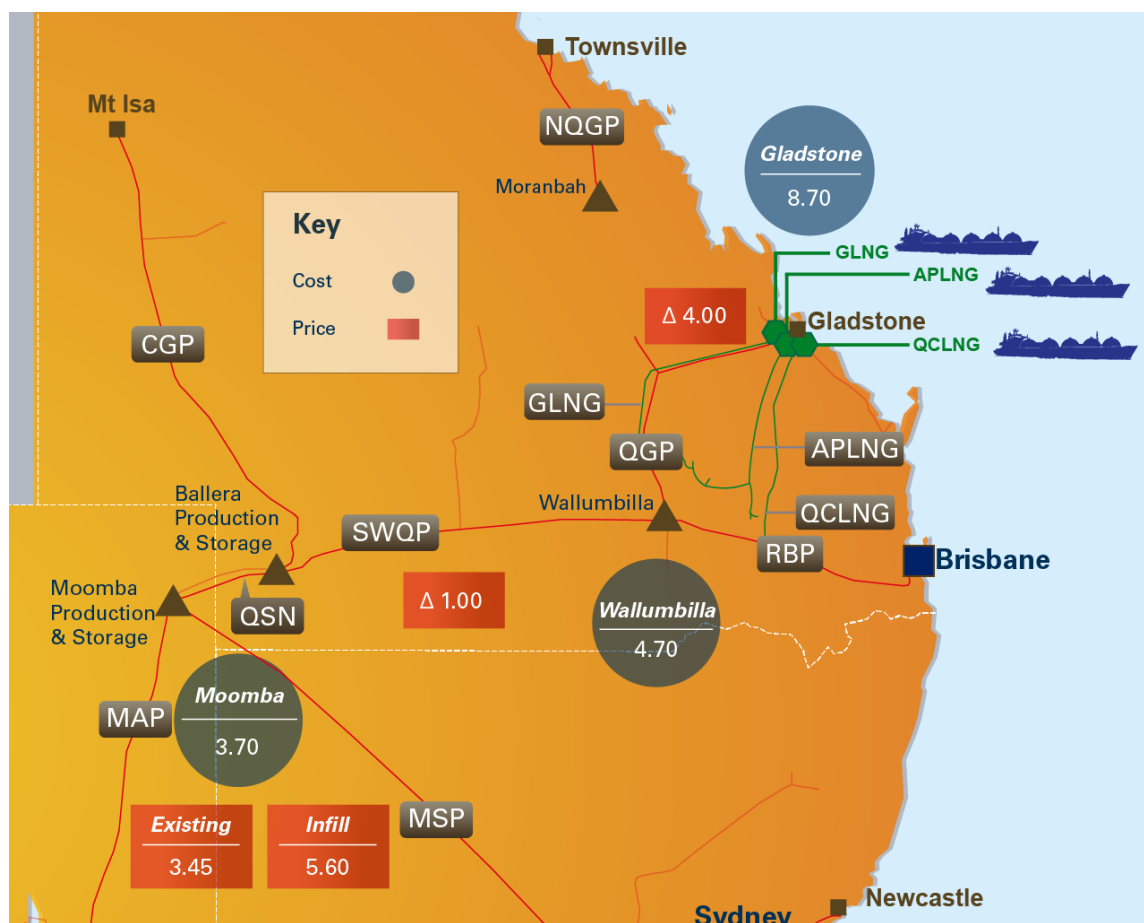
The price of existing Cooper Gas contracts as at June 2015 is up to AUD5.70/GJ. Future prices will be determined largely by demand/supply forces and LNG netback prices.

### 9.1 Export Prices

The price of GLNG sale product at Gladstone, which is a floating price based on Japanese Cleared Crude (“JCC”), will have a major influence on GLNG’s development program. At the date of this report LNG ex-Gladstone sells for approximately AUD9.40/GJ<sup>23</sup>. To derive field netback, costs of at least AUD4/GJ must be deducted to compensate for investment in liquefaction and transmission infrastructure. This results in a net back at Wallumbilla of approximately AUD5/GJ at Wallumbilla.

If LNG operators focus on only marginal costs and ignore the cost associated with sunk liquefaction and transmission infrastructure, Moomba netback prices will increase toward AUD7/GJ. This compares with Core’s estimate of the marginal cost of conventional reservoirs, unconventional plays and the infill program of AUD3.43, AUD4.82 and AUD6.55/GJ respectively and average prevailing contract prices close to mid-AUD5/GJ.

Figure 9.1 Moomba Average Net Back LNG Price vs Average Production Cost | AUD/GJ



<sup>23</sup> This is based on ~15% Brent Crude linkage and 0.75 AUD/USD exchange rate as of 30<sup>th</sup> August 2016.

## 9.2 Domestic Prices

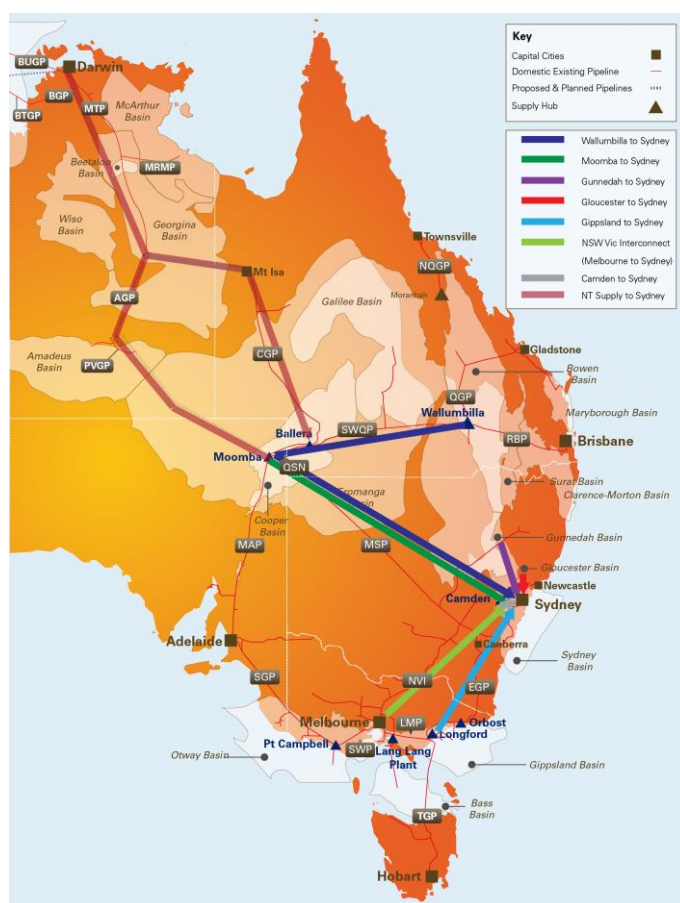
Moomba based gas will be sold into two main domestic markets over the next 10 years – NSW via MSP and Adelaide via MSP. The following figures summarise the competitive forces in each market.

In NSW the primary competition will be Queensland CSG, Gippsland gas, and any larger scale NSW CSG, while secondary competition will come from Victorian gas through the interconnector and potentially gas from Northern Territory (“NT”), via the proposed North East Interconnector Pipeline (“NEGI”)

Core analysis indicates that it is unlikely new future prices (beyond 2018) will fall materially below AUD6.50/GJ, and potentially toward AUD7.00/GJ ex-Moomba in 2015 real terms.

Future gas deliveries from the NT have also been considered. The Grattan Institute (December 2015<sup>24</sup>) assessed Incitec Pivot’s stated saving of A\$55 million on annual gas consumption of around 10 PJ by purchasing gas from the NT Governments Power and Water Corporation and concluded the first gas contracted to use the NEGI pipeline benefits from a very low transport tariff, or a very low gas price from PWC, or both. It should be noted that there are several indications that potential production through the NEGI pipeline is likely to be lower in the foreseeable future including reduction in pipeline specification, lower field activity and political issues regarding future drilling.<sup>25</sup>

Figure 9.2 NSW Demand/Supply Paths



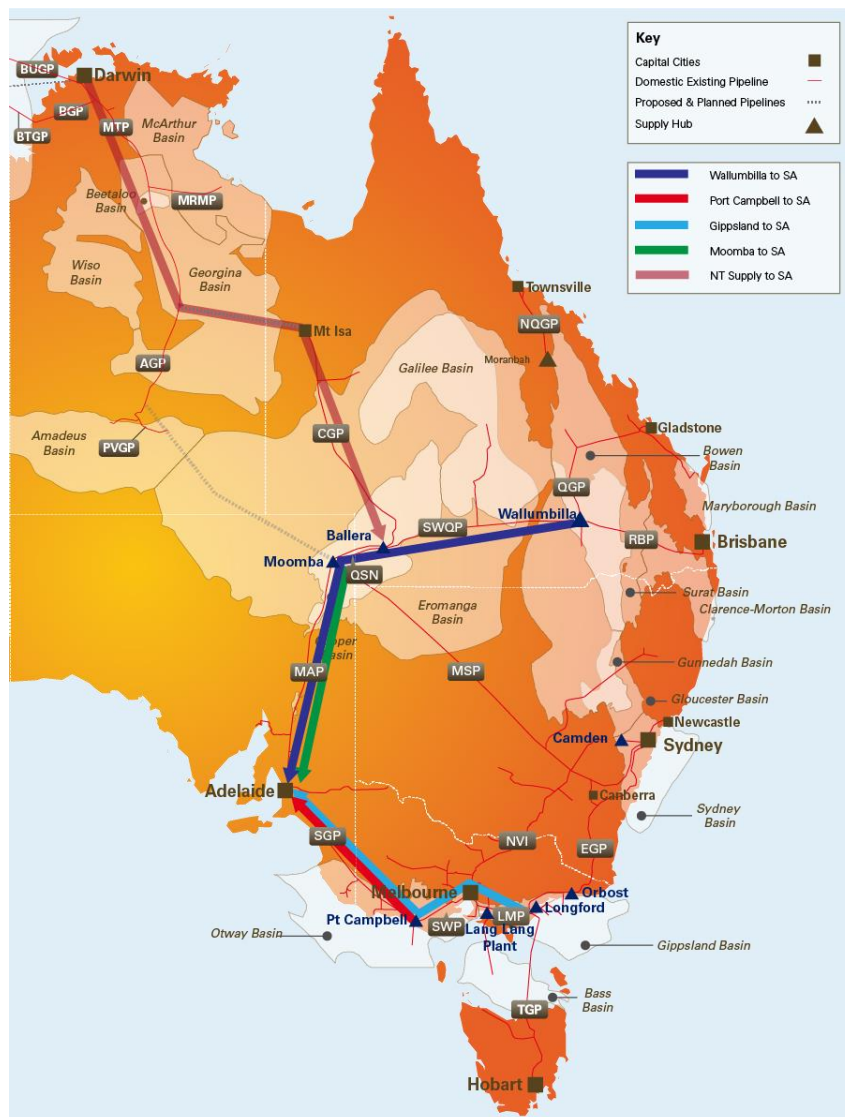
<sup>24</sup> For detail, see : <https://grattan.edu.au/news/connecting-the-dots-the-northern-territory-enters-the-eastern-gas-market/>

<sup>25</sup> See e.g. <http://www.smh.com.au/business/energy/gas/jemena-forced-to-reduce-nt-gas-pipeline-size-amid-drilling-opposition-20160401-gnwgmc.html>



In SA the primary competition will be Queensland and NSW CSG and Victorian gas via SEAGas. Core analysis indicates that it is unlikely future prices will fall materially below AUD6.50-AUD7.00/GJ ex-Moomba in 2015 real terms. Core notes that short term oil prices may cause LNG export prices to fall below this level, however this is expected to be short lived<sup>26</sup> with a portion of LNG supply being diverted to meet domestic market at higher prices, to the extent that flexibility clauses of the LNG contracts allow this to happen. At the limit, some of the Gladstone LNG exporters may find sourcing spot LNG a cost-effective option rather than production, to fulfil contracts – leaving additional gas reserves for an Australian domestic gas market not linked to the price of oil.

Figure 9.3 SA Demand/Supply Paths



<sup>26</sup> Recent upward trend in oil price has reduced likelihood of LNG prices falling below ex field cost.

## 10. Oil Outlook

Core has developed a projection of oil production from existing development wells and proposed development areas for the SACB and SWQ Unit, utilising company and Government sourced data and ValNav modelling software.

### 10.1 Reserves

The following figures present a summary of Cooper Eromanga basins oil reserves at 30 June 2015, at a total level, and allocated by company or JV. The impact of reserve write-downs consistent with reduced oil prices in 2016 can be addressed in an update, when timely.<sup>27</sup>

Figure 10.1 Cooper Eromanga Basin Total Oil Remaining Reserves | '000 bbl

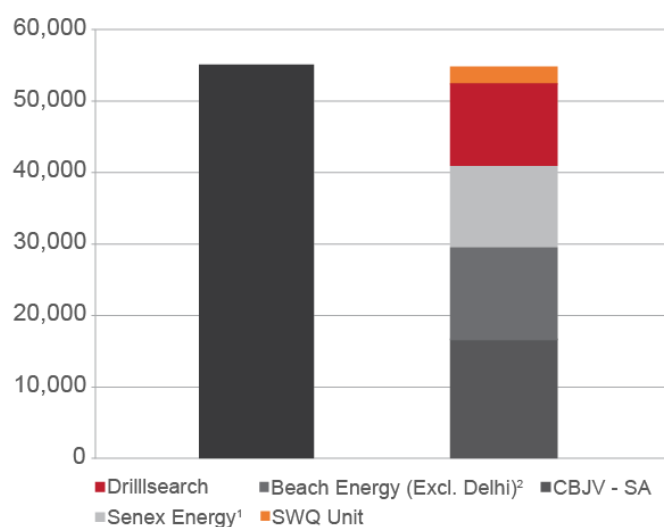


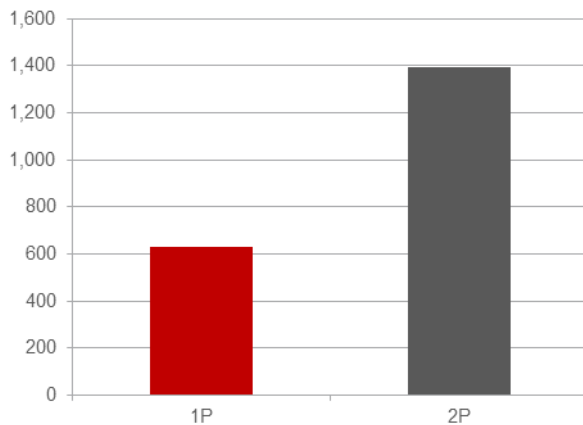
Table 10.1 Cooper Eromanga Basin Reserves by Company | '000 bbl

Operator	2P Oil Reserves as at 30 June 2015
CBJV - SA	~16,725
SWQ Unit	~2,497
Beach Energy (Excl. Delhi)¹	~13,033
Senex Energy²	~11,300
Drillsearch	~11,533
<b>Total</b>	<b>~55,089</b>

<sup>1</sup>Note only includes Beach Energy share of Western Flank permit PEL 91

<sup>2</sup>Note no adjustment has been made to reflect the equity share of Senex Energy and Drillsearch in PEL 182

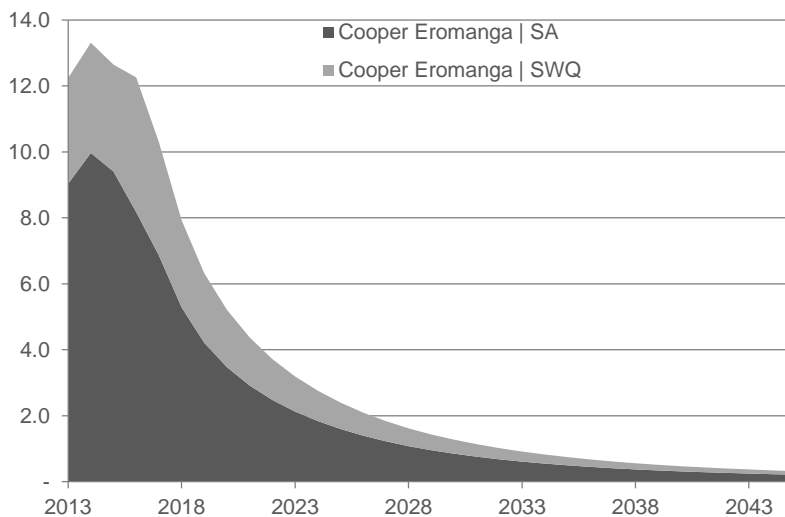
<sup>27</sup> Please note that Beach Energy and Drillsearch completed a merger in March 2016.

**Figure 10.2 Cooper Eromanga Basins JV Oil Reserves as at 30 June 2015 | '000 bbl****Figure 10.3 Cooper Eromanga Basins JV Oil Reserves as at 30 June 2015 | '000 bbl**

## 10.2 Production

### 10.2.1 Production from Existing Wells

Existing development well locations are summarised in Figure 10.6, and the resulting production profiles are presented in Figures 10.4 and 10.5.

**Figure 10.4 Cooper Eromanga Basin Production Forecast | MMboe**

This production is further delineated between CBJV and non-CBJV. This figure highlights the dominant position of the Western Flank region.

Figure 10.5 Production Forecast CBJV and Non-CBJV | MMboe

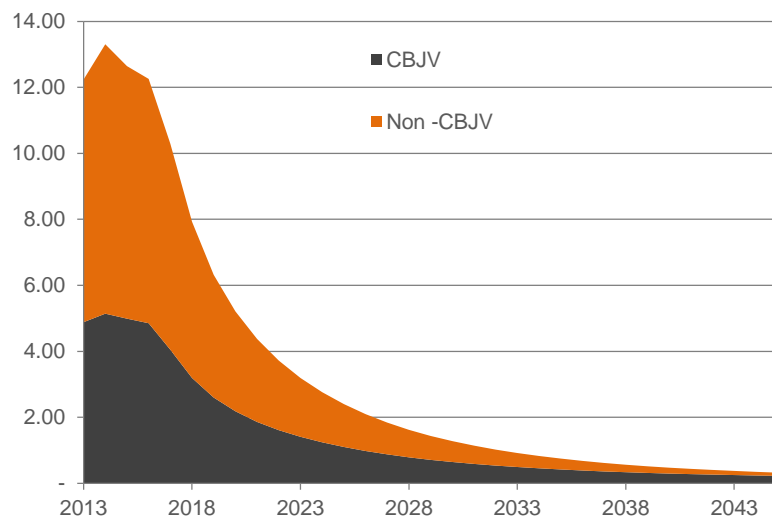
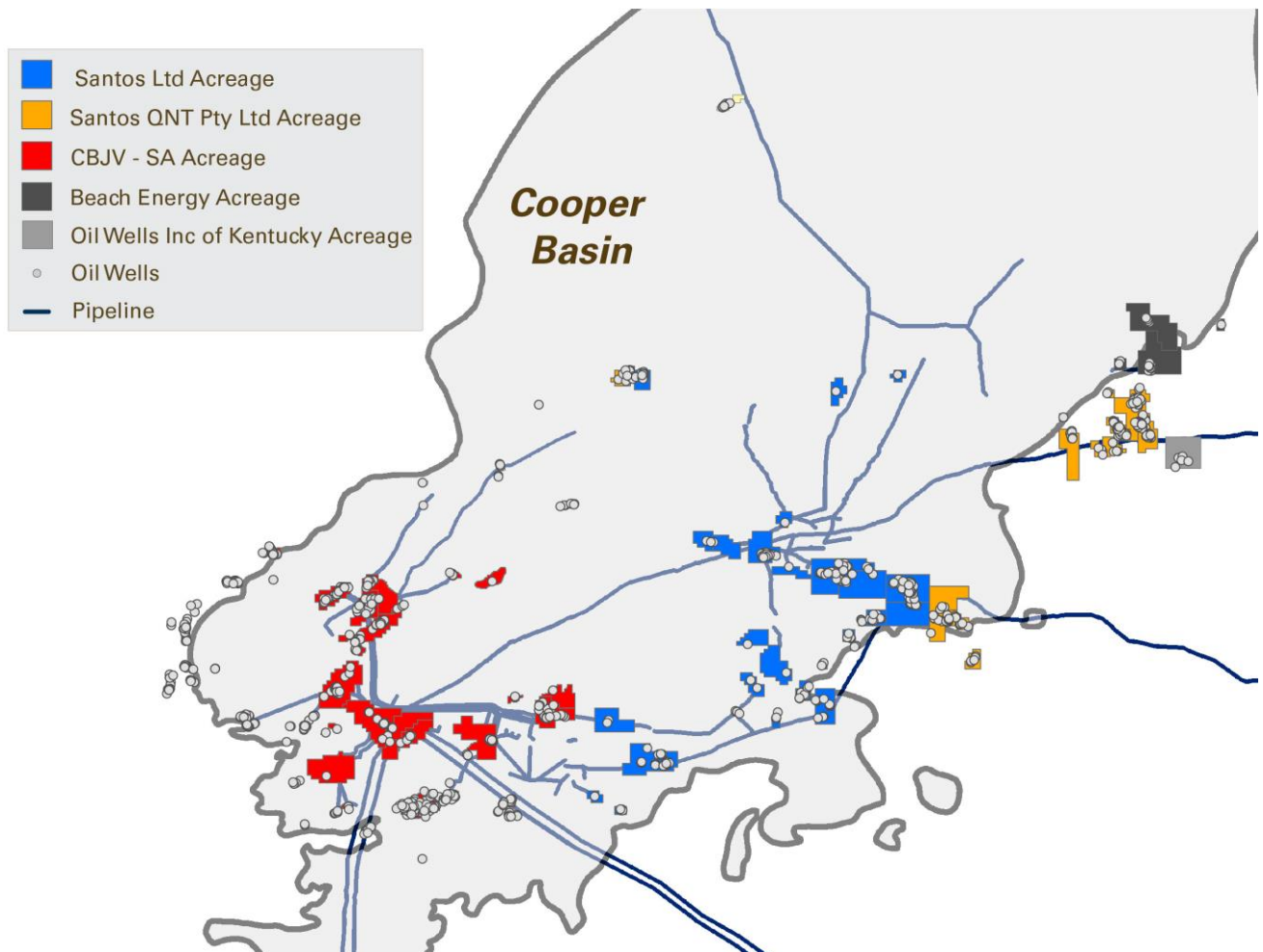


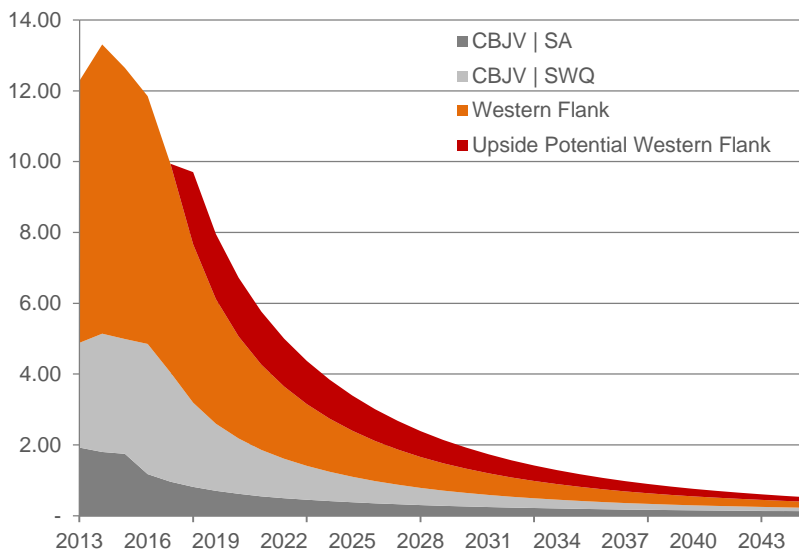
Figure 10.6 Oil Development Well Location Map | SA &amp; Qld



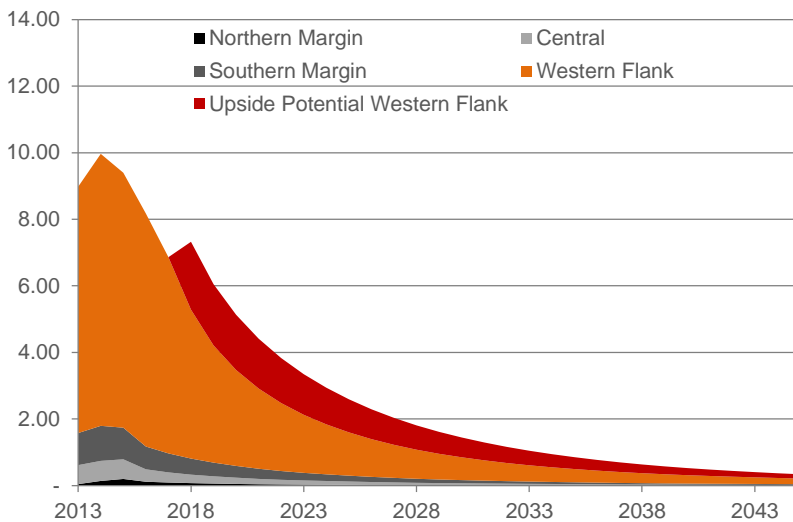
### 10.2.2 Production Growth Potential

Core has developed an estimate of future incremental production which is expected to be associated with Western Flank activity. Total projected production, including additional Western Flank production, is summarized in Figure 10.7, while the total SA share of projected oil production is presented in Figure 10.8.

**Figure 10.7 Total Forecast Cooper Basin Production and Western Flank Potential | MMboe**



**Figure 10.8 SA Forecast Production by Region | MMboe**



## 11. Revenue and Royalty Estimates

### 11.1 Revenue Projections

#### 11.1.1 SACB Revenue

An estimate of total projected revenue from the Cooper Basin SA JV (with a comparison against SWQ) provides the foundation for the analysis of revenue.

Figure 11.1 Total SA Existing CBJV Revenue | AUDm p.a.

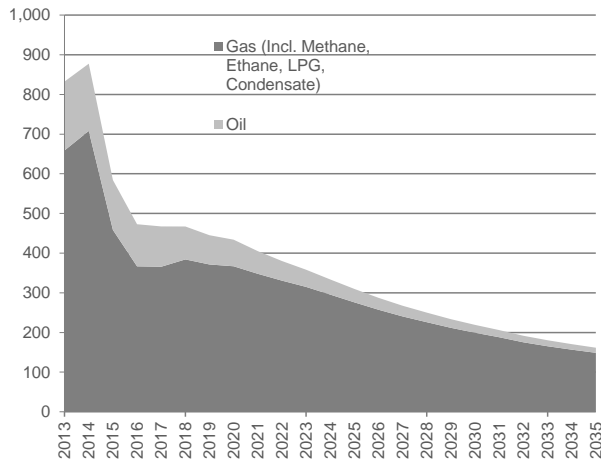


Figure 11.2 Total SWQ Existing CBJV Revenue | AUDm p.a.

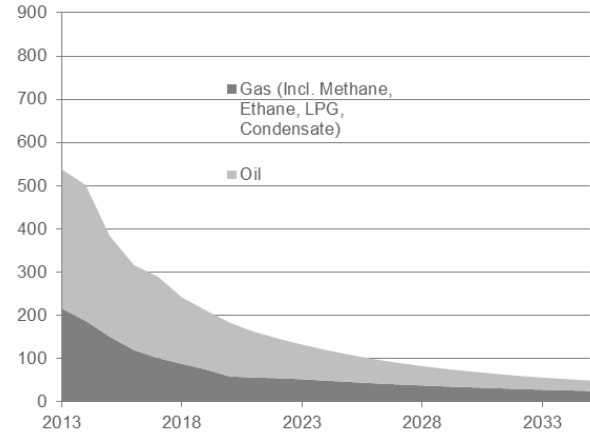


Figure 11.3 Total SA Existing CBJV Revenue | AUDm p.a.

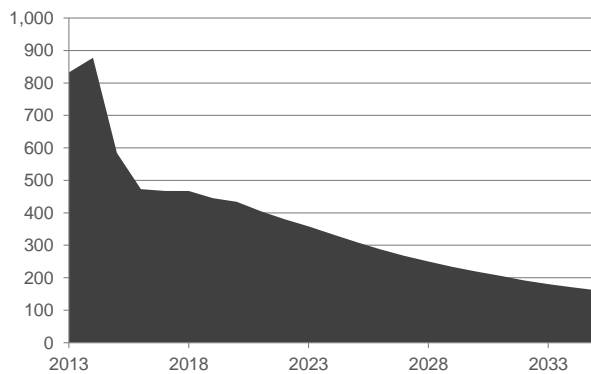
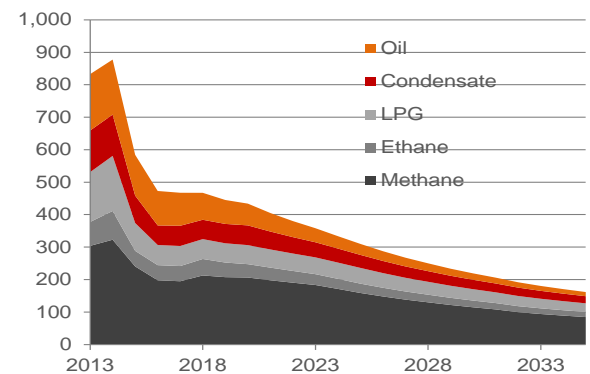


Figure 11.4 SA Existing CBJV Revenue by Product | AUDm p.a.



### 11.1.2 Western Flank Revenue

The projected revenue from the Western Flank has then been derived as summarised below. A conservative 'potential' tranche is included in the projection, representing an additional 20 million barrels of production. There is further upside to potential Western Flank production, reinforced by an USGS estimate in May 2016 that 68 million barrels of undiscovered technically recoverable oil exists in the Cooper and Eromanga Basins.<sup>28</sup>

Figure 11.5 SA Western Flank Oil Revenue | AUDm

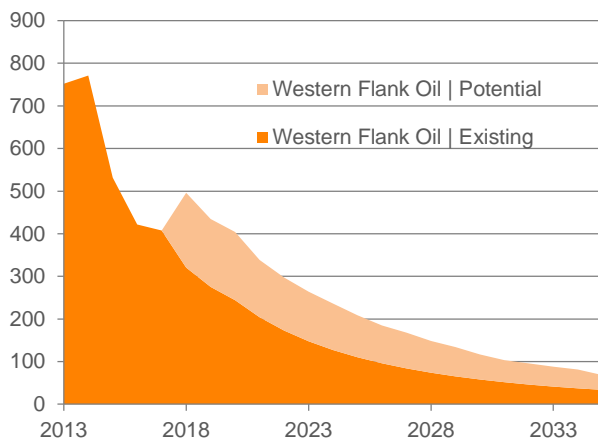
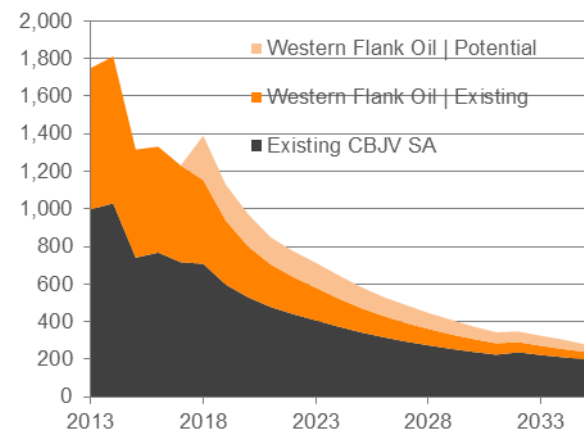


Figure 11.6 Existing SA Cooper and Existing Western Flank Oil Revenue | AUDm



### 11.1.3 Potential Unconventional Play Revenue

Figure 11.7 Potential SA Cooper Revenue from Unconventional Plays by Product Stream | AUDm

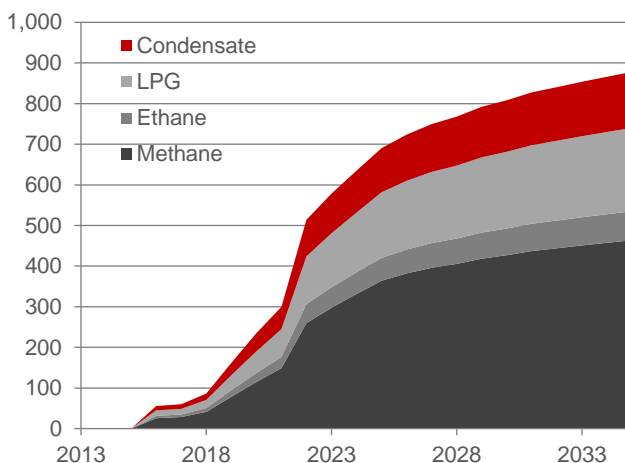
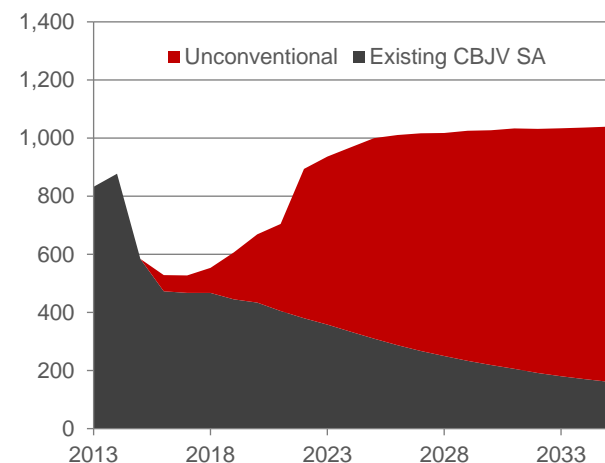


Figure 11.8 Existing SA Cooper CBJV and Cooper from Unconventional Plays | AUDm

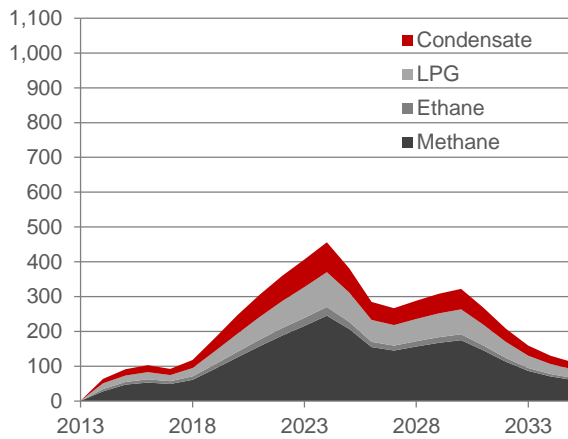


<sup>28</sup> See: <https://pubs.er.usgs.gov/publication/fs20163028>

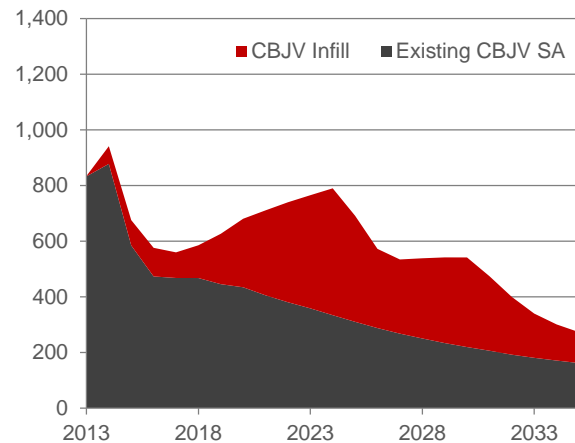
### 11.1.4 Potential Infill Gas Revenue

Revenue analysis concludes with an estimate of the potential revenue associated with the proposed infill drilling program, as summarised in the figures below.

**Figure 11.9 Potential SA Cooper CBJV Infill Revenue by Product Stream | AUDm**



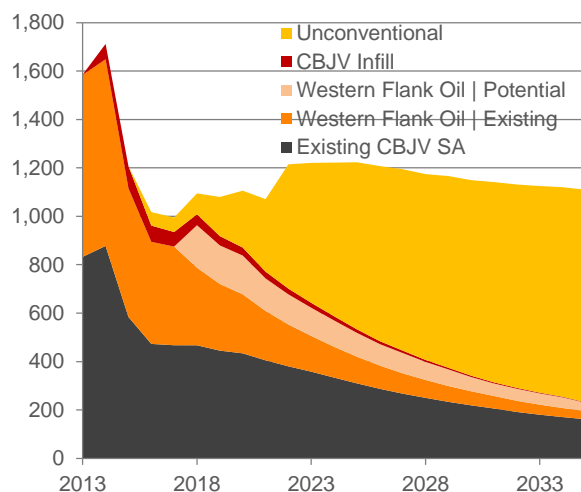
**Figure 11.10 Existing SA Cooper CBJV and Cooper CBJV Infill Revenue | AUDm**



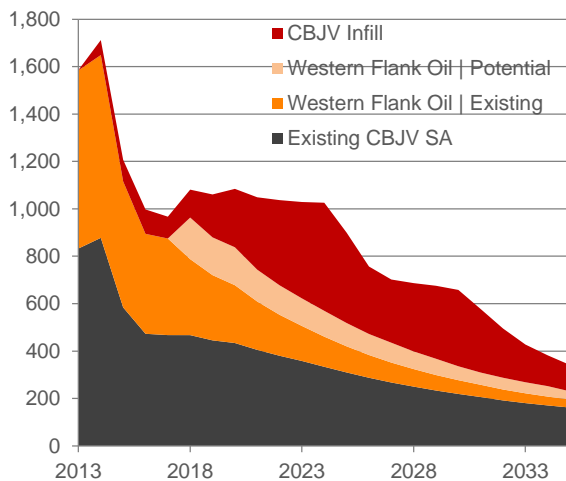
### 11.1.5 Total Potential Revenue

A summation of the previously mentioned revenue streams is presented below to provide a guide to potential SA royalty revenue. Figure 11.11 shows the potential revenue that could be expected from the conversion the unconventional source rock play. Figure 11.12 shows the potential revenue if the infill program was to meet the horizon contract, without any new revenue from unconventional plays.

**Figure 11.11 SA Forecast Revenue from Existing Cooper CBJV, Western Flank Oil and Cooper Unconventional Plays | AUDm**

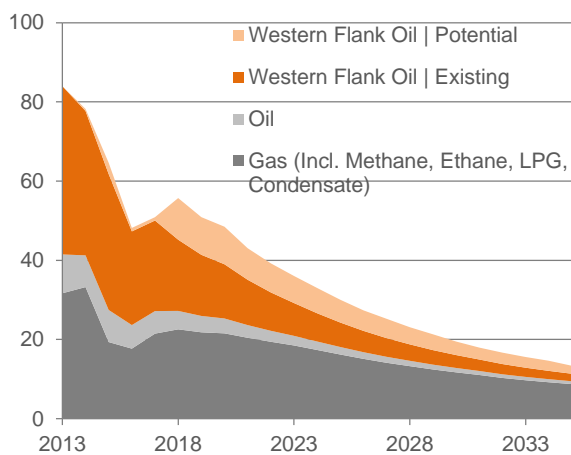




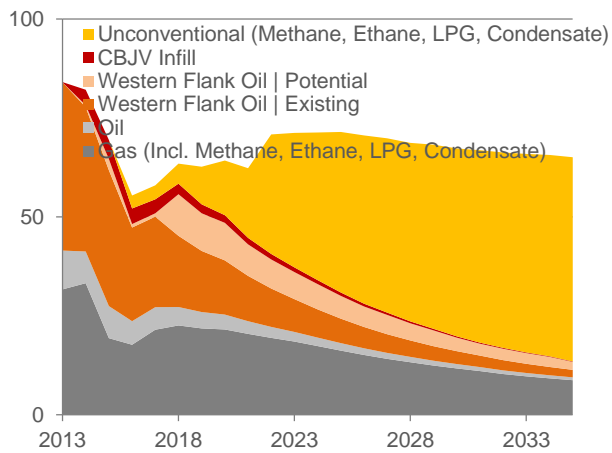
**Figure 11.12 SA Forecast Revenue from Existing Cooper CBJV, Western Flank Oil and Cooper Infill | AUDm**

## 11.2 Royalty Projection

The following figures present Core's estimate of royalties based on the revenue streams mentioned in the previous section. Royalties have been derived by applying an estimate of the net royalty paid as a percentage of revenue, based on public disclosures by DSD-ERD and Cooper Basin operating companies. The exchange rate has been held constant at AUD0.74:1 USD and the long run price of oil is assumed to be 65 USD/bbl

**Figure 11.13 Royalties from existing production sources | AUDm**

**Figure 11.14 Forecast Royalties from SACB JV Existing Gas and Oil, and Existing and Potential Western Flank Oil, and Gas from Unconventional Plays | AUDm**



## 12. Strategic Analysis

### 12.1 The Challenge

The Cooper Basin faces a major strategic challenge arising from of a changing competitive landscape characterised by tightening gas supply throughout Eastern Australia, increasing demand, low oil prices and the commercial imperative to reduce rather than increase gas extraction costs.

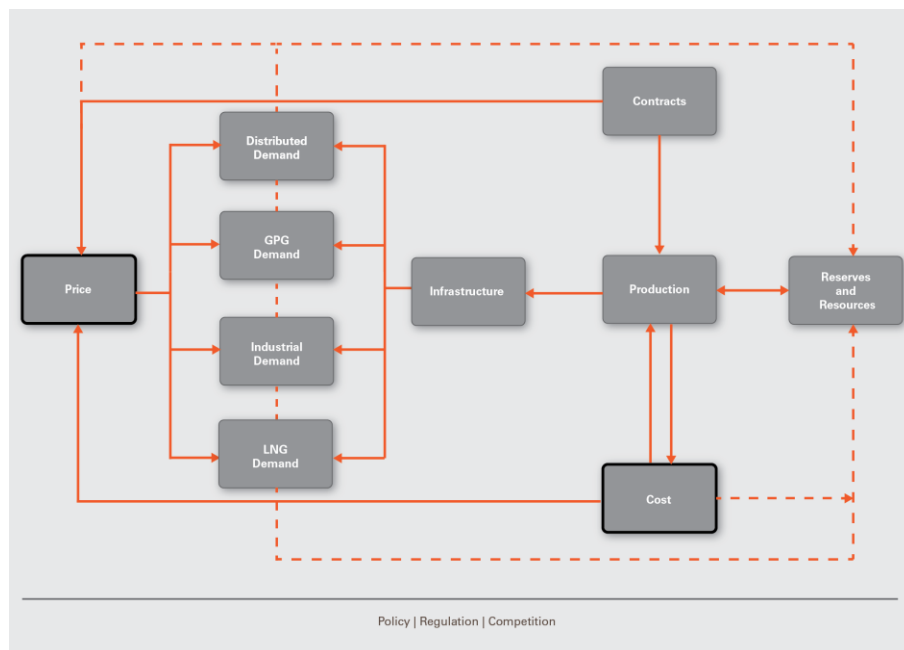
Under a worst-case (unexpected) downside scenario, the Cooper Basin as a whole could face the test of economic viability in the term 2020-2025. It is inevitable that lower gas streams will need cost reductions to stabilize or reduce unit operating costs.

All gas development programs will inevitably remain under continual review to reduce unit operating costs irrespective of future oil prices, to increase competitiveness and profitability.

The primary challenges for the Cooper Basin are costs and well productivity. The Cooper Basin must seek to become a lower marginal cost producer to ensure it is positioned to offer an economic option to supply to LNG markets, and to meet demand from domestic customers without resorting to substitute production sources.

Among key competitive sources of supply are the Roma area CSG fields in the LNG market and NSW CSG in the domestic market. Both of these competitors have serious challenges to meet, too.

Figure 12.1 Price/Cost Challenge



#### 12.1.2 Action Plan

The optimisation of Cooper Basin performance will require a co-operative approach between governments, Petroleum Licence holders, service companies and prospectively, larger industrial consumers of gas. This coincides with plans

by at least Origin<sup>29</sup> to explore an opportunity to sell its Cooper Basin interests, and AGL's stated plans to decision to shut down its gas exploration and production business<sup>30</sup>.

### 12.1.3 Possible Government Actions

The South Australian Government should continue to exercise leadership to influence how value is realised for its SA stakeholders.

Key constructive steps jointly lead by industry and governments include:

- Discussions with producers to share projections and understand variances (increased transparency);
- Develop detailed understanding of development and exploration plans/programs;
- Develop understanding of operating cost and in particular fixed cost components;
- Identify and encourage deployment of new development approaches;
- Continue to monitor performance of competitive supply sources;
- Determine priorities to optimise short term Cooper Basin activity;
- Demonstrate through operations that efficient regulation is effective and trustworthy; and
- Reinvigorate national and international marketing programs to attract investment.

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<sup>29</sup> Core understanding that sale has been temporarily suspended.

<sup>30</sup> For details, see: <https://www.agl.com.au/about-agl/media-centre/article-list/2016/february/review-of-gas-assets-and-exit-of-gas-exploration-and-production>

## 13. Summary and Conclusion

The exposure of the eastern Australian energy system to global markets from 2014, via a new an LNG export sector, has introduced a fundamental change in the dynamics of gas resource commercialization. This change presents both opportunity and challenge.

- Opportunity – potential for the commercialization of a further 30-40,000 PJ to meet the potential sale of LNG throughout the technical life of existing and potential projects (to ~2055), and to meet realistic needs of the domestic market during this same period
- Challenge – the continual pressure to develop resources in a cost competitive manner – estimated by Core to be within the range of USD5-6/GJ ex Wallumbilla, in average real 2016 terms, over the next 15 years.

The SA Cooper Basin has a strong foundation to maintain its position as a material gas supply source - to meet the requirements of both LNG export and domestic market:

- A proven record of performance in commercializing over 11 TCF of gas resource to date;
- A central processing, storage and delivery system linked directly or indirectly to all major markets;
- Substantial existing gas sale contracts linked to the basin;
- A highly efficient and effective regulatory system;
- Developed wells with substantial, low marginal cost deliverability;
- Significant, complimentary existing gas liquids and oil production and material exploration and development potential;
- A diversity of well-established exploration plays – both conventional and unconventional; and
- A southern and northern market which actively seeks cost competitive supply.

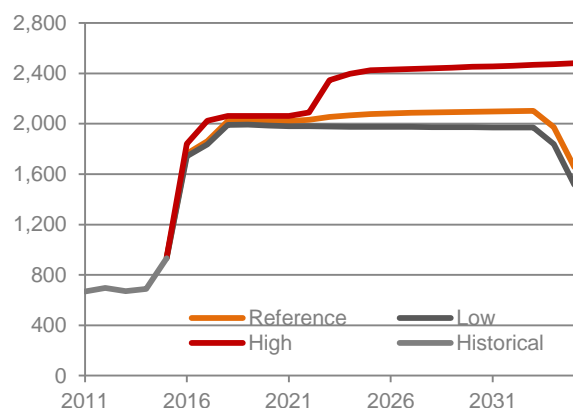
This study concludes that the Cooper Basin has an opportunity to commercialise multi-TCF of resources over the next 5-20 year timeframe, on a cost competitive basis, with an annual production rate of up to 100 PJ p.a. Realisation of this potential will require co-operation by producers, a persistent focus on well productivity and operating cost management. As with all commercial pursuits this will require innovation, including fit for purpose technology; outstanding people; supportive capital structures; and prudent risk, reward management and decision-making.

## A1. Cooper Basin Contestable Gas Market

### Projected Demand

Eastern Australia gas demand is projected to increase significantly from 2016 onwards, largely related to gas production from LNG projects. Figure A1.1 provides a graphical representation of Eastern Australia's domestic and LNG demand to 2035. Under the reference scenario, LNG demand ramps up between 2015 and 2018 before stabilising at approximately 1,400PJ p.a. to 2033. LNG demand then drops in 2034 and 2035, as LNG export contracts mature. In contrast, domestic demand is projected to decline from 622 PJ in 2015 to 546 PJ by 2020, before recovering to 635 PJ by 2035. Much of the initial fall in domestic demand is attributed to reduced Gas Powered Generation (GPG) consumption, as a result of the RET policy, resulting in growth in penetration of renewables capacity, and the repeal of the carbon tax, which reduces GPG's cost competitiveness against coal-fired generators. In addition, the emergence of a shortfall in the ramp up phase of Eastern Australia LNG sector encourages GPG operators to divert their contracted volumes to the higher-value LNG market.

Figure A1.1 Projected Eastern Australian Gas Demand by Scenario | PJ



This analysis focuses on the domestic demand currently met by existing Cooper Basin production, namely demand from South Australia and New South Wales, and LNG demand, in particular from GLNG which is known to currently have supply shortfall to meet LNG export contracts. Domestic demand projections for New South Wales and South Australia (markets most likely to be supplied by the Cooper Basin) are provided in the following figures.

Figure A1.2 Forecast Domestic SA Demand | PJ

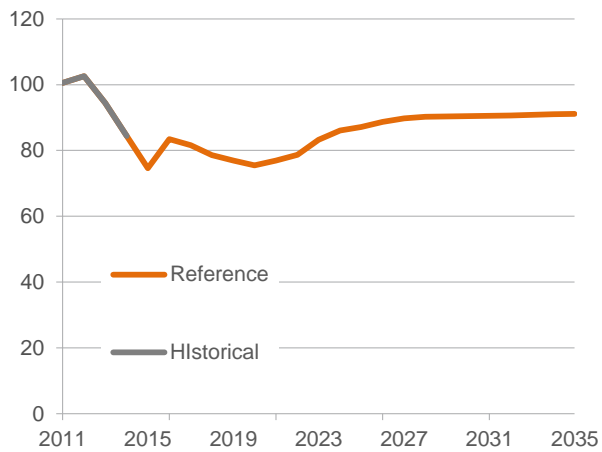


Figure A1.3 Forecast Domestic NSW Demand | PJ

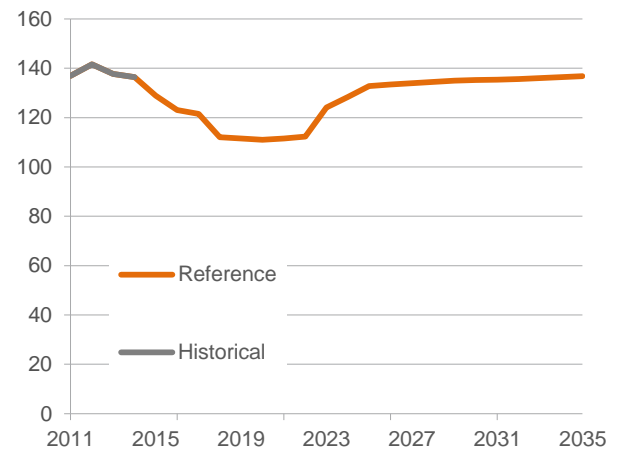
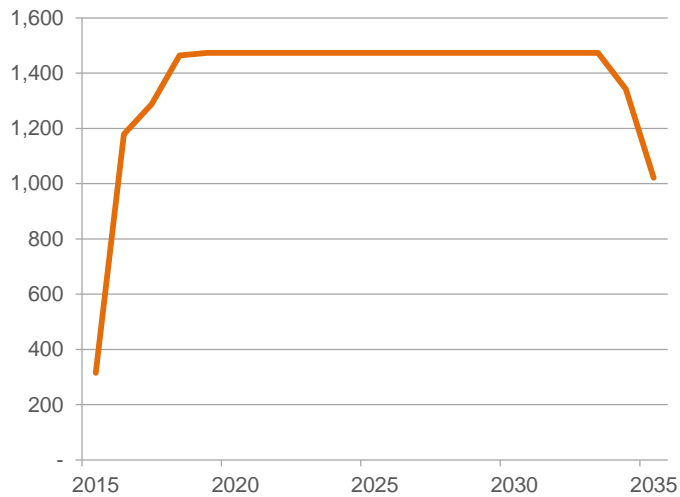


Figure A1.4 Total LNG Demand – Existing Contracts Only | PJ



## Committed Supply

The following figures present a summary of NSW and SA contracted supply to 2035. These contract volumes, set against projected demand provide the level of unfulfilled demand to 2035.

Figure A1.5 NSW and SA Committed Supply | PJ

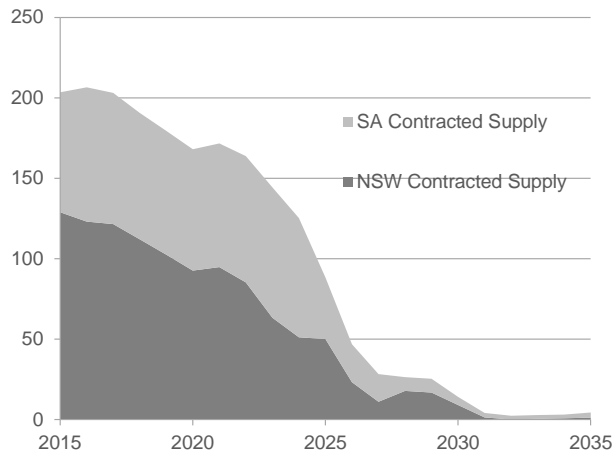
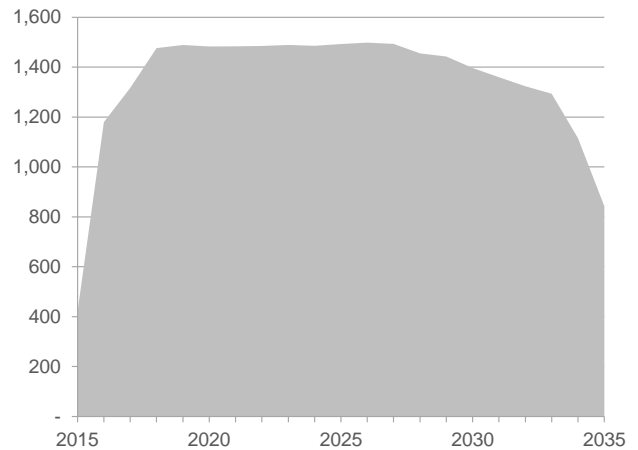


Figure A1.6 LNG Committed/Contracted Supply | PJ



## Contestable Market

Core has undertaken an analysis of unfulfilled demand to determine that portion which is considered to be contestable from a Cooper Basin perspective. The results are presented below. In Figure A1.8 new Cooper Basin development is expected to be competitive against only a portion of potential QLD CSG supply into Gladstone. However material improvements in cost/productivity could increase the contribution from Cooper Basin sources materially. This potential higher level of production is presented as a sensitivity.

Figure A1.7 Full Contestable Market Available to Additional Cooper Basin Supply | PJ

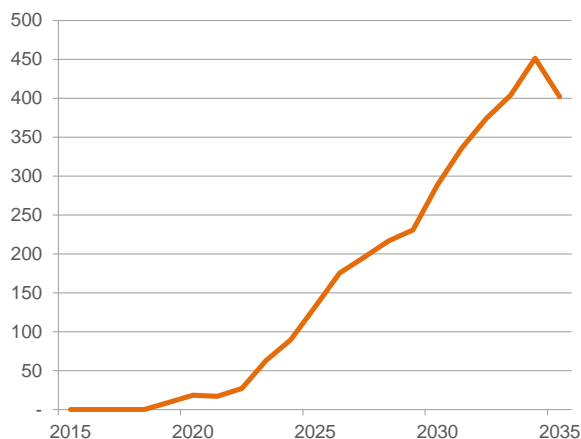
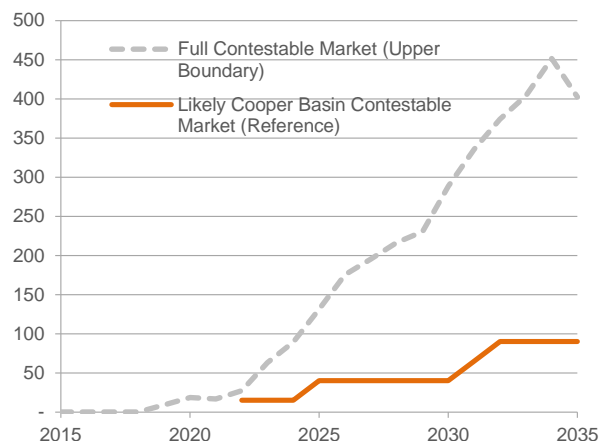


Figure A1.8 Likely Contestable Market Available to Additional Cooper Basin Supply | PJ





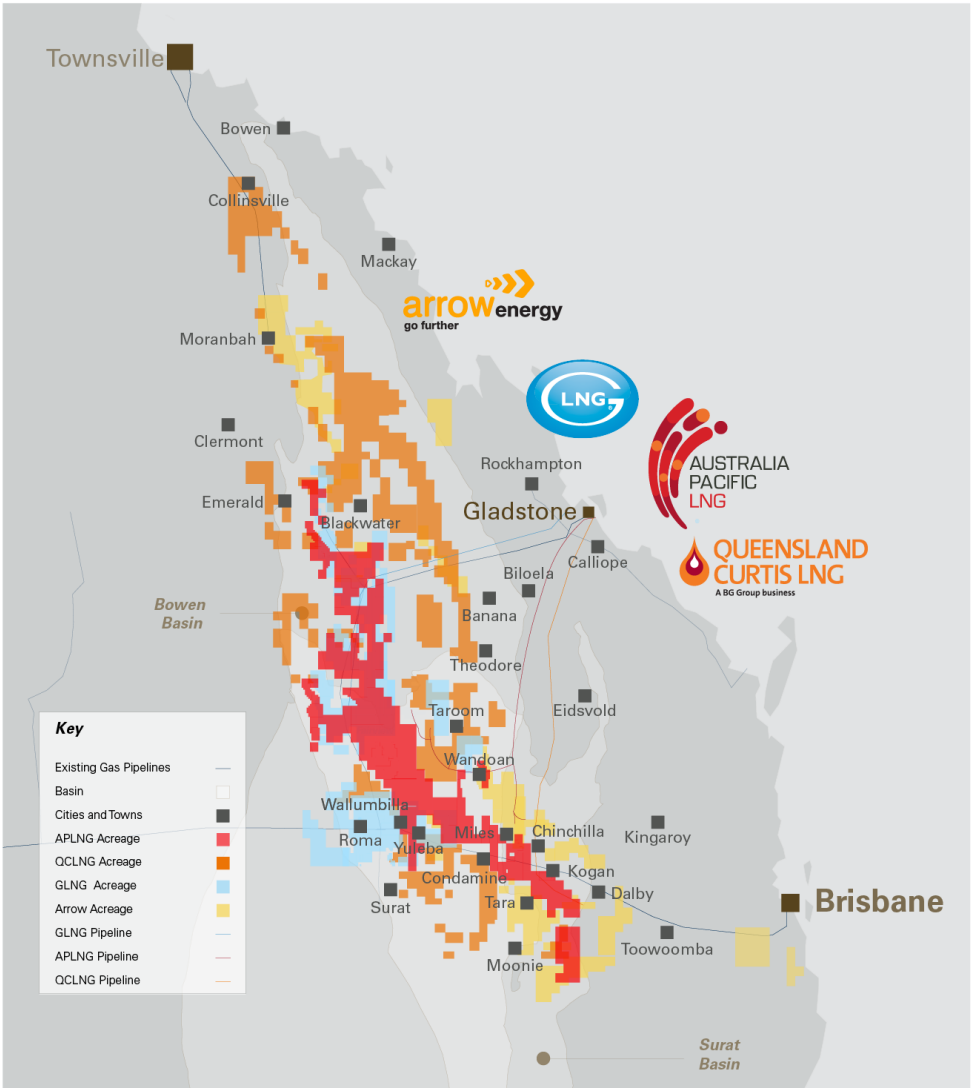
## A2. LNG Projects

Major features of the three projects are summarised in the following table, and a location map showing principal acreage positions is presented on the following page. Arrow's acreage is shown for completeness as Core believes it is likely that gas from this acreage will flow to LNG within the study period. If the reference oil price for LNG contracts remains low for an extended term – deals might be done by LNG plant operators to reduce aggregate marginal operating costs by rationalising recently commissioned LNG export facilities in Queensland.

Table A2.1 LNG Projects Details

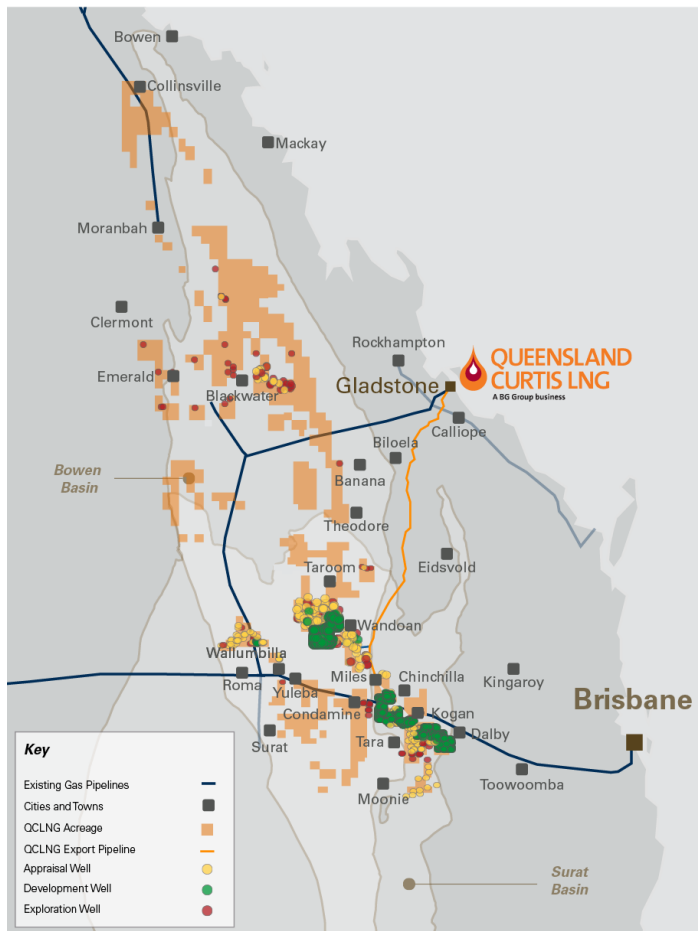
	QCLNG	APLNG	GLNG
Equity	BG Group (100%)	Origin Energy (37.5%) ConocoPhillips (37.5%) Sinopec (25%)	Santos (30%) Petronas (27.5%) Total (27.5%) KOGAS (15%)
Capacity   Mtpa	8.5	9.0	7.8
Est. CAPEX   USD bn	20.4	25.2	18.5
Reserves as at 30 June 2015   PJ	10,162	13,802	5,598
Customers	CNOOC   3.6 Mtpa CNOOC   5 Mtpa (+BG Portfolio) Tokyo Gas   1.2 Mtpa Chubu Electric   122 cargos PowerGas Singapore   3 Mtpa	Sinopec   4.3 Mtpa Sinopec   3.3 Mtpa Kansai Electric   1 Mtpa	Petronas   3.5 Mtpa KOGAS   3.5 Mtpa
Third Party Gas Sources	APLNG AGL Toyota Gas storage arrangement with AGL	-	Santos Horizon Contract APLNG Landbridge/Mitsui

Figure A2.1 Eastern Australian LNG Projects



## QCLNG

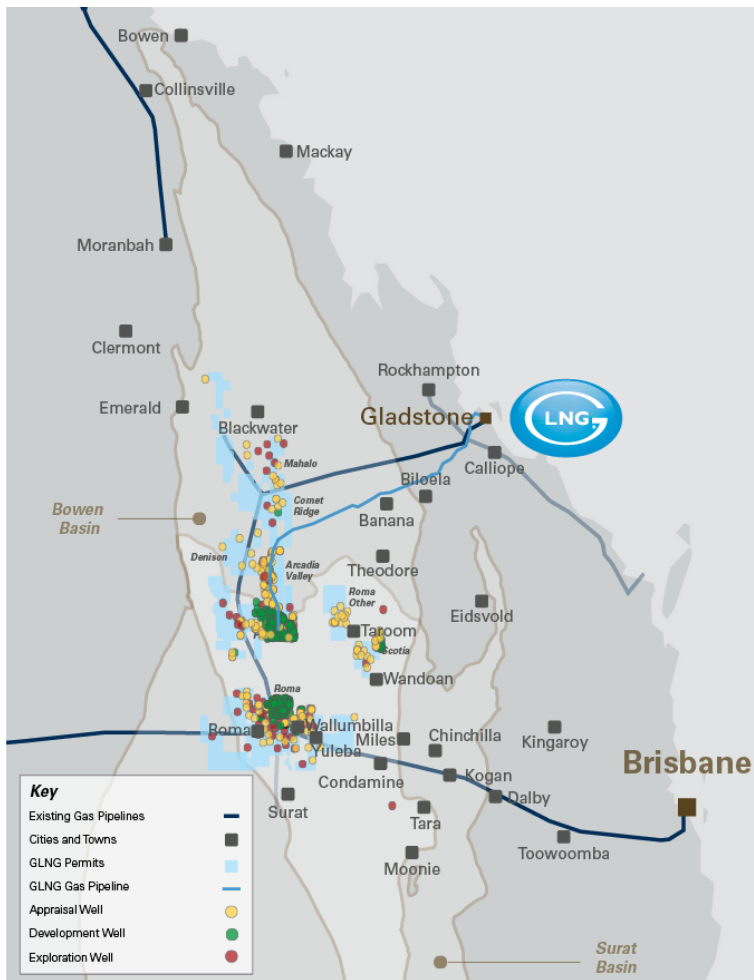
Figure A2.2 QCLNG Acreage



- BG Group acquired QCLNG interests through a takeover of Australian Stock Exchange ("ASX") listed Queensland Gas Company ("QGC")
  - BG Group commenced development of the QCLNG project in 2010.
  - The QCLNG liquefaction facility has a total capacity of 8.5 Mtpa across two trains.
  - BG Group announced that it had loaded its first LNG cargo on the 29 December 2014.
  - BG Group announced it had completed the sale of its wholly owned 543 km pipeline linking natural gas fields and the Queensland Curtis Liquefied Natural Gas (QCLNG) export facility to APA Group on the 3rd June 2015.
  - QCLNG has several LNG contracts with CNOOC (China), Chubu Electric (Japan), Tokyo Gas (Japan) and PowerGas (Singapore) totaling 13.21 Mtpa. A proportion of this LNG is likely to be supplied through BG's global LNG portfolio.
  - QCLNG project is estimated to have approximately 10,000 PJ of 2P reserves as at 30 June 2015, and is likely to require approximately 11,000 PJ of production to fulfil contracts to 2035.
- Shell acquired BG in February 2016.

## GLNG

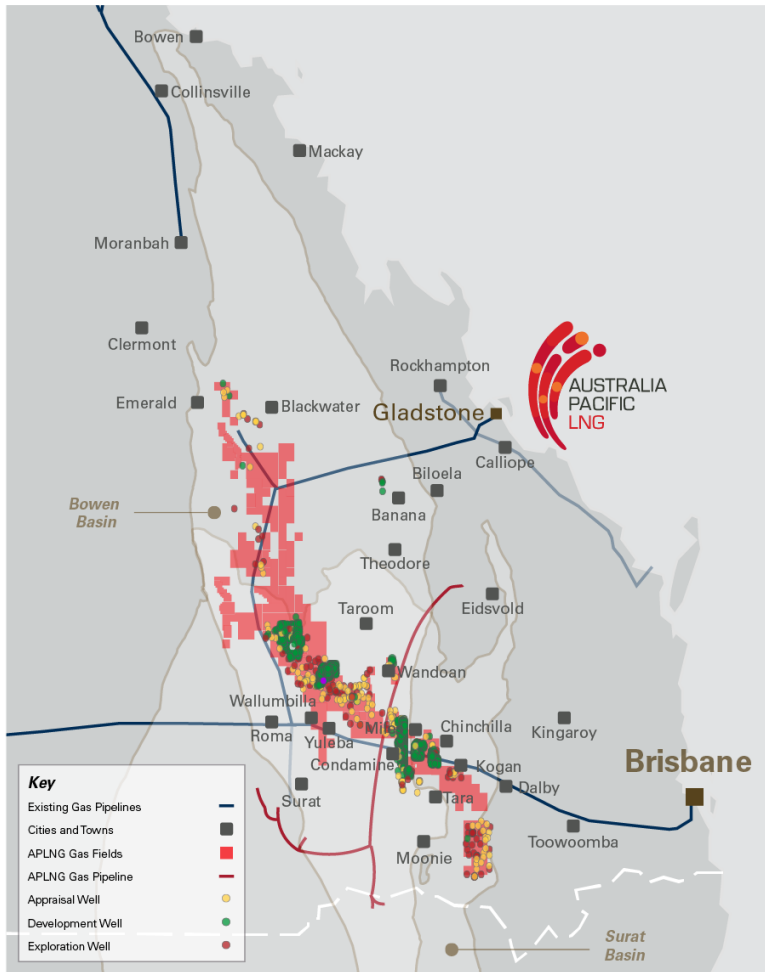
Figure A2.3 GLNG Acreage



- The GLNG project involves Santos, Petronas (Malaysia), Total (France), and KOGAS (South Korea).
- The liquefaction facility has a total capacity of 7.8 Mtpa across two trains.
- GLNG loaded its first LNG cargo as of 16 October 2015 and commissioned its second LNG train in May 2016.
- Offtake agreements exist with Petronas and KOGAS totaling 7 Mtpa.
- The GLNG project is estimated to have approximately 5,600 PJ of 2P reserves as at 30 June 2015, and is likely to require approximately 6,000 PJ of production to fulfil contracts to 2035.
- Additional gas supply has been sourced through third party contracts with Santos (Horizon Gas Contract 750 PJ), Origin Energy, Landbridge/Mitsui, and APLNG

## APLNG

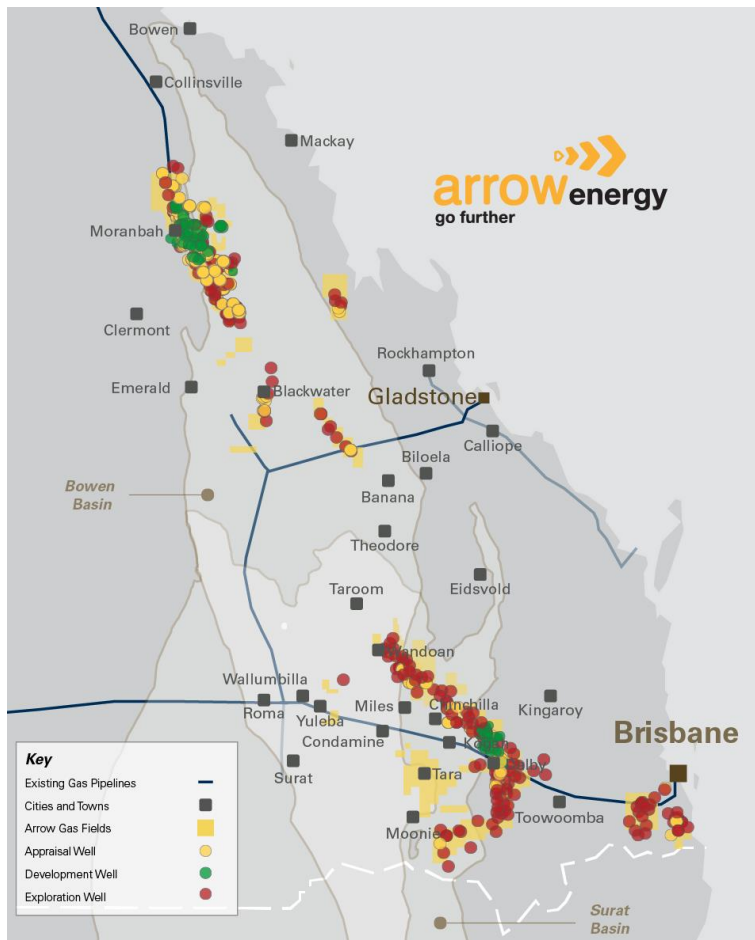
Figure A2.4 APLNG Acreage



- Joint venture between Origin Energy, ConocoPhillips, and Sinopec (China).
- Liquefaction facility has a total capacity of 9 Mtpa across two trains.
- Offtake agreements with Sinopec and Kansai Electric (Japan) totaling 8.6 Mtpa.
- First gas reached APLNG's liquefaction facility on 11 February 2015, with the first LNG cargo likely to be shipped in late 2015
- Has agreed to supply gas to GLNG and QCLNG
- Estimated to have approximately 13,800 PJ of 2P reserves as at 30 June 2015, and is likely to require approximately 11,000 PJ of production to fulfil contracts to 2035.

## Arrow Qld CSG

Figure A2.5 Arrow Acreage



- Potential to enter LNG sector via gas sale or earning equity into an LNG project. Could supply gas to a potential third train for an existing Qld LNG project.
- Arrow Energy is a joint venture company between Shell and Petrochina. (equal share).
- The majority of Arrow Energy's existing CSG production is used to supply generators in Townsville and regional Queensland.
- Arrow Energy is estimated to have approximately 10,300 PJ of 2P reserves as at 30 June 2015.

## A3. Supply Areas

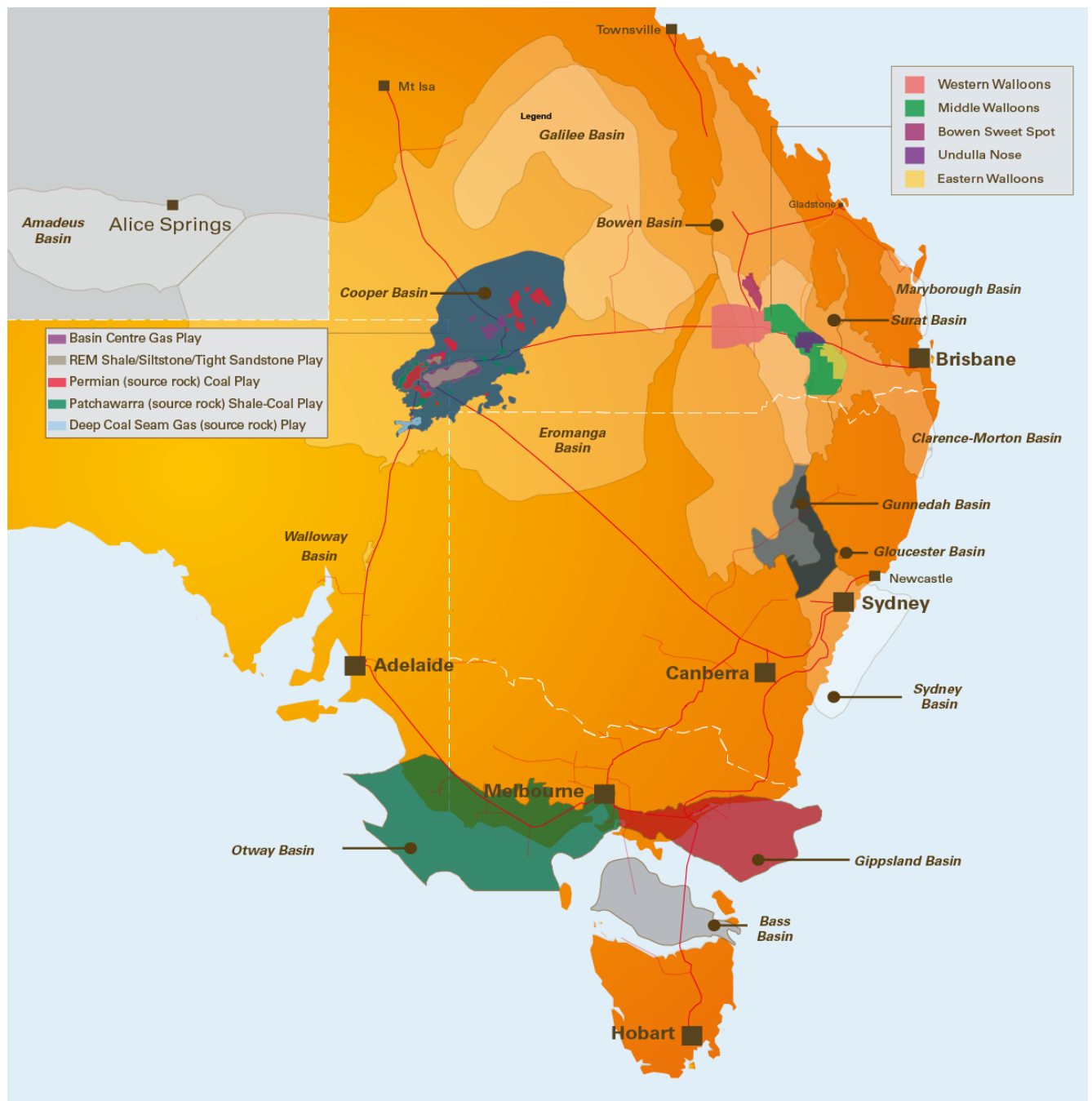
Table A3.1 2015 Production and Reserves by Supply Areas

	Supply Region	Production Categories	2015 Production <sup>(1)</sup>   PJ	Reserves as at 31 December 2014   PJ
Conventional	Gippsland	GBJV & Turrum & Kipper, Longtom & Sole	266	3,411
	Cooper Eromanga	Cooper Eromanga Basin	65	1,640
	Otway	Otway Gas Project, Minerva, Casino, Henry and Netherby	95	700
	Bass	Bass Basin	18	166
Coal Seam	Bowen Sweet Spot   Spring Gully	QLD CSG - ORG/APLNG	50	1,782
	Bowen Sweet Spot   Fairview	QLD CSG - GLNG	50	1,946
		QLD CSG -	-	408
		QLD CSG -	55	1,502
		QLD CSG - BG/QCLNG	140	2,711
	Middle Walloons	QLD CSG - Arrow	-	1,413
		QLD CSG -	80	7,314
		QLD CSG - BG/QCLNG	60	5,331
	Eastern Walloons	QLD CSG - Arrow	24	4,352
		QLD CSG -	-	808
		QLD CSG - BG/QCLNG	140	1,820
		QLD CSG - GLNG	-	2,658
	Other QLD CSG	QLD CSG - Other	14	1,392
		QLD CSG - Arrow	2	2,008
		QLD CSG - GLNG	10	882
		QLD CSG - Ironbark / ORG	-	256
	Gunnedah	Gunnedah Basin	-	971
	Gloucester	Gloucester Basin	-	462
Unconventional   Other	Cooper Basin	Cooper Eromanga Basin	-	5
<b>Total</b>			<b>1,069</b>	<b>43,938</b>

(1) Indicative of production expected in 2015 based on GBB (AEMO-Gas Bulletin Board) production values YTD to 30 September 2015.

(2) Please note that the supply table excludes minor supply regions, Moranbah reserves (~2,502PJ) and QLD CSG minority interests across LNG projects (~2,523 PJ predominantly APLNG minority interest in QCLNG acreage).

Figure A3.1 Map of Supply Areas





## Gippsland Basin | Conventional

Figure A3.2 Gippsland Basin



The Gippsland Basin is situated in south eastern Australia, about 200km east of the city of Melbourne, covering an area of ~46,000 km<sup>2</sup>, with approximately two-thirds of the basin located offshore.

Nearly four billion barrels of oil and eight trillion cubic feet ("TCF") of gas have been produced from the Gippsland Basin to date.

A network of pipelines brings produced hydrocarbons to the onshore petroleum processing facilities near Longford for delivery mainly to Victoria, NSW and Tasmania.

Production from the basin is focused on Victoria and NSW markets with total annual production typically falling within the range of 240 to 270 PJ or over 40% of EA supply.

In 2007, the Kipper development was approved to produce new supplies of natural gas and liquids through new and existing Bass Strait facilities. First production is expected in 2016.

Several petroleum systems operate in the basin. The large oil and gas fields discovered early in this history are all related to large anticlinal closures in the Central Deep at top-Latrobe Group level, where coarse-grained coastal plain and shallow marine barrier sands provide excellent reservoirs. Further top-Latrobe discoveries were made in increasingly deeper water, including erosional channel plays in the eastern part of the basin such as Blackback, Marlin and Turrum. In these, channel cut and fill sediments are preserved as complex successions of intraformational reservoir and seal facies.

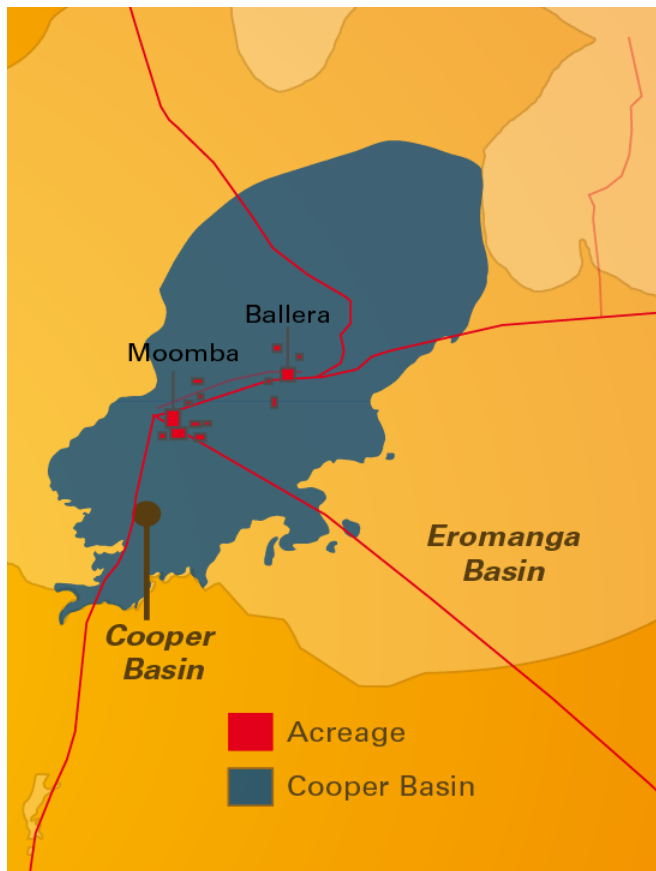
Other top-Latrobe play types are known to exist on the flanks of the basin.

More than 300 exploration wells have been drilled within the basin and approximately 90,000 line km of 2D seismic data and more than forty 3D seismic surveys have been acquired. Consequently, exploration within the Gippsland Basin is mature in comparison to other Australian basins, though it is actually relatively under-explored in comparison to many other prolific basins around the world.

Recent estimates of the basin's undiscovered resource potential consider that there is 2–4 TCF of gas and up to 600 MMbbl of liquids yet to be discovered in the Gippsland Basin (GeoScience Victoria, unpublished data).

## Cooper Basin | Conventional

Figure A3.3 Cooper Basin



The Cooper Basin commenced commercial production in 1969, with first deliveries into Adelaide.

The Cooper Basin extends across SA and Qld, however the majority of production is now from the SA acreage.

The Basin produces oil and gas and a significant portion of historical gas has been produced with associated liquids.

The conventional plays are mature with evidence of material decline over recent years.

The remaining reserves are held by joint venture participants Santos (~67%), Beach (~20%) and Origin (~13%).

The allocation of reserves/ future production varies between venturers with Santos favoring sales to GLNG, Origin favoring the domestic market and Beach selling into either market to optimise value but to date has contracted with Origin and thus into the domestic market.

Production in 2015 was approximately 70PJ and reserves stood at approximately 1,600PJ.

Source rocks are carbonaceous shale and thick (up to 30 m) coal.

The main gas reservoirs occur primarily within the Patchawarra Formation (porosities up to 23.8%, average 10.5%; permeability up to 2500 mD) and Toolachee Formation (porosities up to 25.3%, average 12.4%; permeability up to 1995 mD).

Shoreface and delta distributary sands of the Epsilon and Daralingie formations are also important reservoirs.

Conventional play types include anticlines, fault traps and structural-stratigraphic traps.

Over 2,000 wells have been drilled within the Basin.

Approximately 190 gas fields and over 700 gas wells are in production.

Cumulative sales to end June 2015 are ~5,600 PJ of gas, 186 mmbbl oil, 82 mmboe of LPG and 80 mmboe of condensate

The May 2016 USGS estimate of undiscovered technically recoverable gas from conventional reservoirs in the Cooper Basin is 964 billion cubic feet of gas (1,017 PJ), with a 95% probability range of 509 to 1,633 billion cubic feet of gas (537 to 1,723 PJ), 19 million barrels of natural gas liquids (MMBNGL) with a 95% probability range of 9 to 34 MMBNGL.<sup>31</sup>

<sup>31</sup> For details see: <https://pubs.er.usgs.gov/publication/fs20163028>

## Otway Basin | Conventional

Figure A3.4 Otway Basin



The on/offshore Otway Basin is approximately 500 km long from Cape Jaffa in South Australia to just west of Melbourne and extending to the northwest of King Island in Bass Strait.

The Otway is prospective for gas and oil in conventional reservoirs as well as unconventional reservoirs.

Discovered, developed and producing fields include Thylacine-Geographe (T-G), Minerva and Casino-Henry-Netherby. In addition, the Halladale and Black Watch fields owned by Origin and adjacent to T-G is planned to commence production in 2017.

Total production from the Otway, across three complexes was approximately 100PJ in 2014.

The main exploration targets in the Otway Basin are the Waarre Sandstone at the base of the Sherbrook Group and sandstones of the Pretty Hill Formation and Katnook Sandstone/Windermere Sandstone Member in the Early Cretaceous section.

The main source rocks occur in the Early Cretaceous section. Regional and intraformational seals exist in the Pretty Hill, Laira, Eumeralla and Flaxman formations, the Belfast, Skull Creek and Pember mudstones and mudstones and marls of the Wangerrip, Nirrandra and Heytesbury groups.

Play types include faulted anticlines, large anticlinal features and tilted fault blocks.

Shale gas, shale oil and tight sandstone plays are potential targets in the depocentres of the Otway Basin

## Bass Basin | Conventional

Figure A3.5 Bass Basin



The Bass Basin is situated on Australia's south-eastern margin, underlying the shallow seabed between Tasmania and the Victorian mainland.

There have been a number of sub commercial discoveries and only one discovery, the Yolla field, has moved to commercial development - known as the BassGas project which is operated by Origin.

Development of the BassGas project began in 2001, led by Origin.

Over the period to its official launch in 2006 AUD750 million was invested to develop the Project.

BassGas is designed to produce approximately 24 petajoules of sales gas per annum together with 1 million barrels of condensate and 75,000 tonnes of LP Gas.

The BassGas project consists of an offshore wellhead platform connected by pipeline to the gas processing facility at Lang, Victoria. Gas has historically been produced from two wells, Yolla-3 and Yolla-4 until recent development (see below).

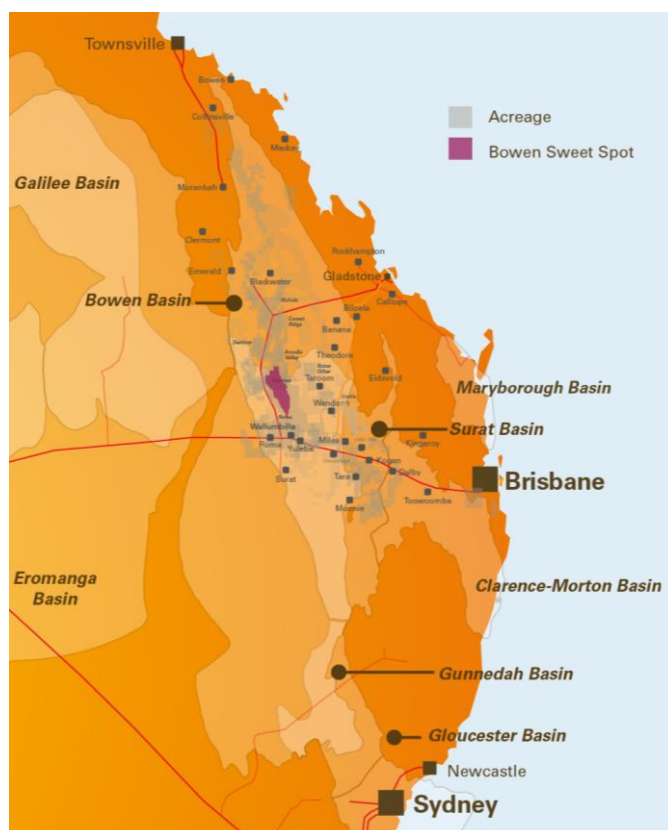
Once extracted, the gas and liquids from the Yolla field are transported 150km via an undersea pipeline to the Lang Gas Processing Plant 70 km South of Melbourne in Victoria.

Here, the gas is processed for sale before being transported through the onshore underground gas pipeline to the Victorian Principal Gas Transmission Pipeline near Pakenham, Victoria.

The BassGas Mid Life Enhancement Project (MLE) commenced in 2011. This project comprised the installation of an accommodation module (completed in 2012) and the installation of a compression module (deferred). The joint venture also drilled further development wells (Yolla-5 and Yolla-6) during mid to late of 2015. Production reached over 60TJ/d during 3Q 2015.

## Bowen (Sweet Spot) | CSG - Queensland

Figure A3.6 Bowen Sweet Spot



The Bowen Basin sweet spot is Permian age CSG and includes two main projects — Fairview and Spring Gully

### Fairview

The Fairview project area comprises the following tenements: ATP 655P (2 parts); PL's 90; 91, 92, 99, 100 and 232.

Fairview is jointly owned by Santos and Origin.

Santos acquired its interest in the Fairview field in 2005. The acquisition included over 4,000 square kilometres of exploration acreage in the Comet Ridge area of the Bowen Basin.

Santos' Fairview acreage now forms part of the GLNG venture and has been identified as a major source of supply for the GLNG, with domestic contracts maturing by 2017.

During the construction phase of the GLNG project, gas is produced from the Fairview field and sold to domestic customers in Queensland.

The GLNG Field Development Plan requires Fairview to deliver a final plateau gas rate of approximately ~350 TJ/d to the project or over 120 PJ p.a.

Fairview is a high quality CSG field with world class characteristics in terms of coal thickness, gas content, gas saturation and permeability.

### Spring Gully

The Spring Gully project area comprises the following tenements: PL's 195, 200, 268 and 204. It is located approximately 70km northeast of Roma.

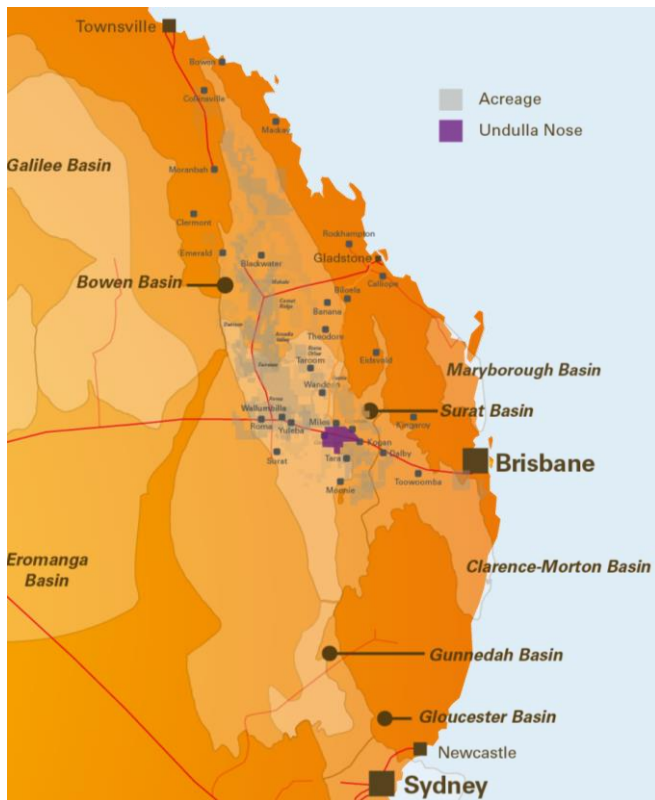
It is majority owned and operated by Origin/APLNG and it commenced domestic production in 2005, and is being developed to supply both domestic and APLNG markets.

The APLNG Field Development Plan requires Spring Gully to deliver a final plateau gas rate of 350 TJ/day to the project.

Spring Gully is also a high quality CSG field with world class characteristics in terms of coal thickness, gas content, gas saturation and permeability.

## Undulla Nose (Sweet Spot) | CSG - Queensland

Figure A3.7 Undulla Nose

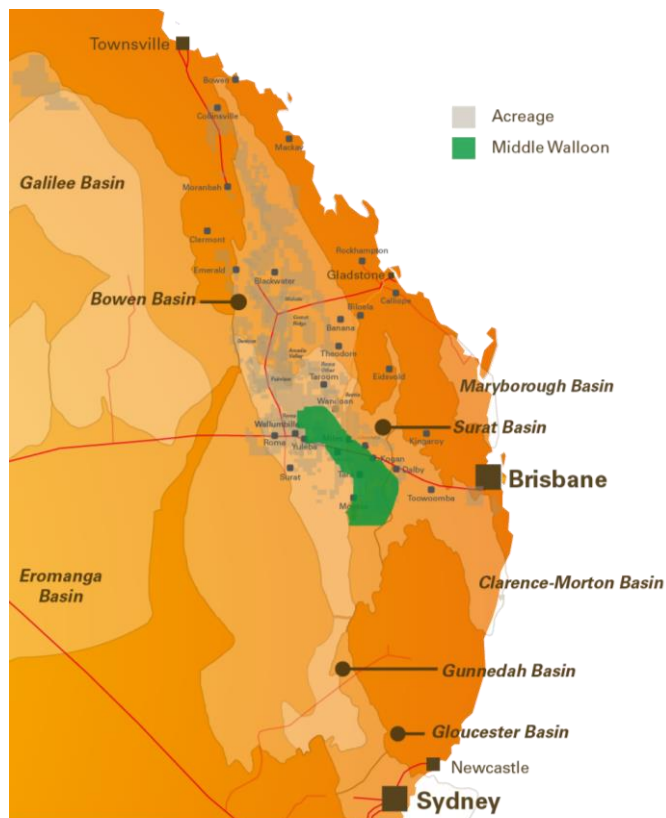


The main supply areas defined within the Undulla Nose are held by QCLNG, APLNG and to a lesser extent Arrow.

The Undulla Nose comprises distinctive geological features including high natural fractures which result in high permeability and lower cost of production.

## Walloons | CSG - Queensland

Figure A3.8 Middle Walloon



Commercial production of CSG from the Jurassic Walloon Coal Measures of the Surat Basin began in January 2006 from the Kogan North CSG area west of Dalby.

CSG produced commercially from the Walloon Coal Measures is typically obtained from seams 300–600 m deep. The term Walloon Coal Measures is used for the combined thicknesses of the Taroom Coal Measures (lower), Tangalooma Sandstone and the Juandah Coal Measures (upper).

For the purpose of this Study, the Walloons are dissected into three regions and profiles for each region are provided below:

- Undulla Nose — mainly QGC/QCLNG and Origin/APLNG resources
- Eastern — mainly Arrow Energy resources
- Middle — mainly QCLNG and APLNG
- Western — mainly Roma - GLNG resources.

Coals in the Surat Basin were not as deeply buried as those in the Bowen Basin and therefore are less thermally mature, with generally lower gas contents. Vitrinite reflectance values for coals in the Walloon Coal Measures in Queensland range from 0.35% to 0.6% Rv. Seams in the Walloon Coal Measures are generally not as thick or laterally continuous as those in the Bowen Basin, but generally have a higher permeability. This has allowed the Surat Basin CSG to be commercialised using a range of well-completion techniques.

The Walloon Coal Measures lie beneath the Kumbarilla Beds and above the Eurombah Formation sandstone. The Walloon Coal Measures are complex; are characterised by carbonaceous mudstone, siltstone, minor sandstone and coal; and contain the following formations:

- Juandah Coal Measures
- Tangalooma Sandstone
- Taroom Coal Measures
- Durabilla Formation.

Of these four formations, the Taroom and Juandah Coal Measures, which generally range in depth from 150 to 750 m below ground surface across the project development area, are targeted for exploration and production.



Figure A3.9 Eastern Walloon

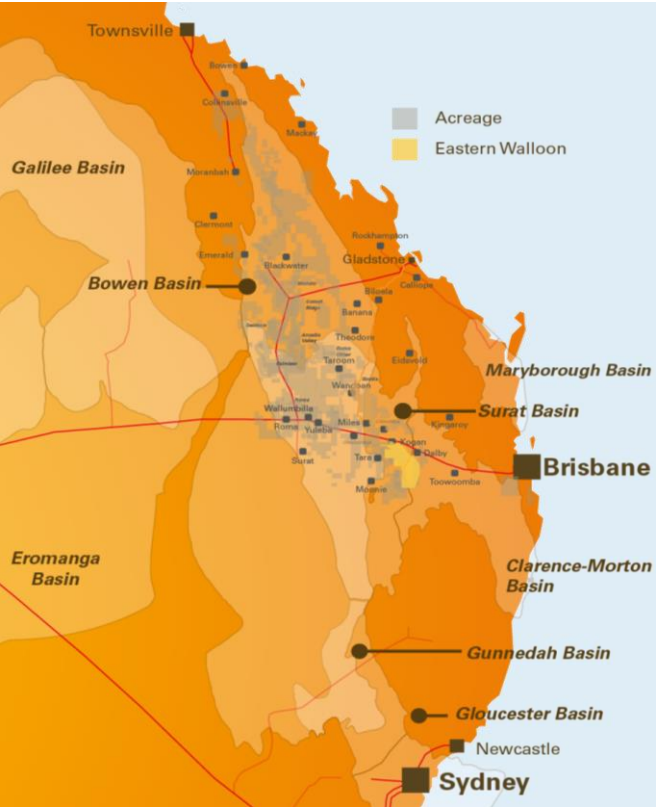
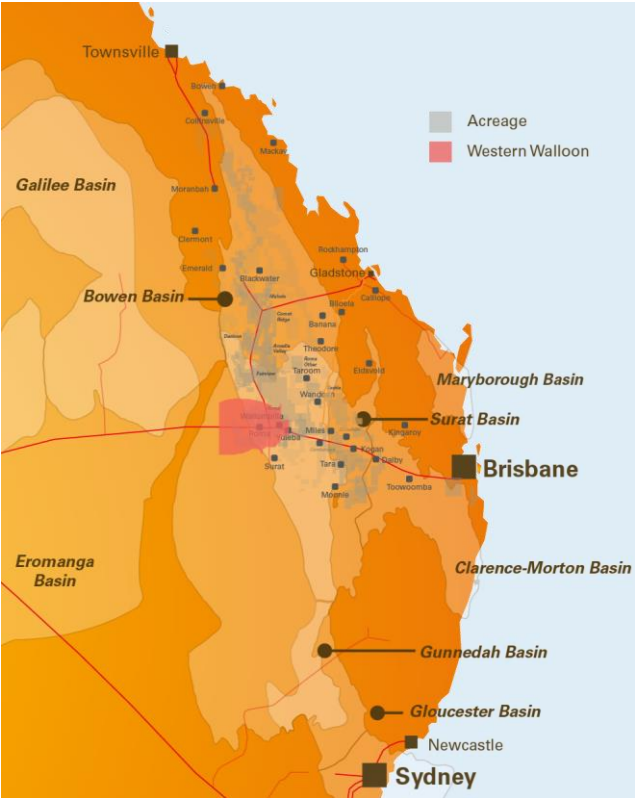


Figure A3.10 Western Walloon





## Gunnedah | CSG - NSW

Figure A3.11 Gunnedah



The major potential production area in the Gunnedah is Santos' proposed development of gas from coal seams in the Narrabri area in north west NSW.

Santos began exploring for coal seam gas in NSW in 2008, completing seismic surveys and drilling core holes to assist in the assessment of the geology of the area. In 2010, the first pilot in the area, the four-well Kahlua pilot, was completed.

In November 2011, Santos completed its acquisition of Eastern Star Gas' (ESG) acreage and operations near Narrabri, including six completed pilots in and around the Pilliga. The acquisition was over AUD900 million, a portion of which was on sold to Energy Australia, and this has since been written down by EA for accounting purposes.

Santos states that any development project based around the resources in the Pilliga could deliver half of NSW natural gas demand — circa 50–60 PJ p.a. or approximately 140 TJ/d based on Core estimates.

NSW Government policy is a significant impediment to timely development.

The Maules Creek and the Black Jack Formations contain the majority of economic coal deposits in the Gunnedah Basin. Coal seams in the Maules Creek Formation vary between 1.5 and 3.5 m in thickness with frequent splitting. The Brown Seam is known for its good quality with a raw ash yield between 11.8 and 27.3%. The most important seams within the Black Jack Formation are the Hoskissons and Melvilles seams, ranging between 2.5 and 3.5 m, and >1 and 17 m, respectively. The Hoskissons seam is a medium ash, high volatile bituminous coal. Vitrinite reflectance in the basin varies between 0.5 and 0.9% (Tadros, 1995a).

The seams within both formations contain coal seam methane deposits as well as potential conventional gas plays as indicated by recent exploration activities (NSW DPI, 2011a). The Arkarula Sandstone Member and the Watermark Formation are considered to have the best potential for sources of petroleum since both are marine and liptinite rich. Permian reservoir units are included within the Black Jack Group and Watermark Formation.

Gunnedah is widely recognised as having high levels of CO<sub>2</sub> - in order of 30%+.

## Gloucester | CSG - NSW

Figure A3.12 Gloucester



The Gloucester Basin is a small Permian basin, 60x12 km, 100 km north of Newcastle (NSW) with two major coal bearing sequences.

- Gloucester Coal Measures
- Dewrang Group.

AGL Energy acquired 100% of the interests in PEL 285 in the Gloucester Basin from the AJ Lucas Group and Molopo Australia for A\$370 million in 2008.

Its proximity to Newcastle makes it well suited to supply AGL's NSW customer base, as an alternative to historical reliance on Cooper Basin and Gippsland supply. NSW Government policy acts as a major impediment to timely development. AGL continues to assume production from 2018-19. Core estimates that the field will produce 15-20 PJ p.a.

The Gloucester Basin is reasonably complex, and highly faulted at depth, and the continuity of coal seams at depth, and laterally, is relatively poor. The average total coal thickness within the basin package is ~30 m, at depths between 200–700 m. The Waukivory pilot project, in the north of the basin has undergone deep drilling by Lucas Energy, which demonstrated gas contents of 12–25 m<sup>3</sup>/t, permeability of 300 milidarcies to 1millidarcies between 100m–500m.

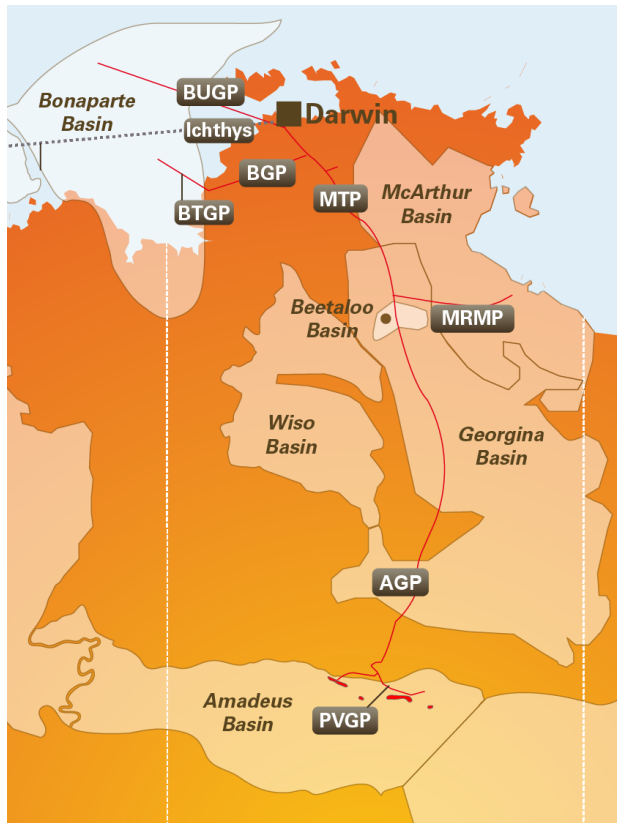
The nearby LMG03 well also achieved production flow rates (>1050 mcf/d (thousand cubic feet per day), Lucas Energy 2008). Many of the coal seams within the Basin are minor aquifers, with AGL's observations (see SRK AGL002 2010) noting wells that intersect seams ~150m below ground level tend to have low water production (~3.9 m<sup>3</sup>/day), while seams above 150m depth are wet, and gas wells tend to have higher water production (~28-96 m<sup>3</sup>/day).

On 4 February 2016, AGL announced<sup>32</sup> it would not proceed with its proposed Gloucester Gas Project (and production at the Camden Gas Project would cease in 2023).

<sup>32</sup> AGL. "Review of gas assets and exit of gas exploration and production", 4 February 2016. Available at: <https://www.agl.com.au/about-agl/media-centre/article-list/2016/february/review-of-gas-assets-and-exit-of-gas-exploration-and-production>.

## Northern Territory | Conventional and Unconventional

Figure A3.13 Northern Territory | Unconventional



### Introduction

NT conventional production (oil and gas) has been focused on the Amadeus Basin (Mereenie and Palm Valley – see Amadeus below)

A range of companies have acquired acreage to pursue unconventional plays in NT and a few have exited after preliminary exploration results were unsatisfactory. Over 50TCF of resource potential has been reported but there is no commercial production to date.

The main basins targeting unconventional plays include the McArthur, Beetaloo, Georgina and Wiso as presented on the Figure opposite.

The recently elected NT government instigated a moratorium on hydraulic fracturing on 14 September 2016. A panel of experts will investigate hydraulic fracturing in the NT to decide how long the moratorium would last and if it would result in a permanent ban.<sup>33</sup>

### McArthur Basin

The McArthur Basin is located south-east of Katherine, Northern Territory, covering an area of approximately 180,000 square kilometres. Small oil shows and bitumen/pyrobitumen from many stratigraphic intervals. The McArthur Group and Roper Group having most potential with 28 wells drilled.

### Georgina Basin

The basin has two established Middle Cambrian source rocks, one developed at the base of the Lower Arthur Creek Formation, and the other within the Thornton Limestone. These source rocks are responsible for ubiquitous oil and gas shows in some 30 wells drilled in the basin. A sub-commercial gas flow of ~200 Mcfd from the Coolibah formation was recorded in the exploration well Ethabuka 1.

### Wiso Basin

The Wiso Basin is a large sedimentary basin of 160,000km<sup>2</sup>. The basin is sparsely explored, with no modern seismic data and well penetrations are limited to a few stratigraphic wells up to 130 metres deep on the north-east margin. Oils shows were encountered in several of these wells.

### Beetaloo Basin

This is a sub basin of the McArthur. Two major exploration programs are underway, one involving Santos and the other Origin.

### Amadeus Basin

The only currently producing onshore basin in the Northern Territory is the Amadeus Basin, where gas production commenced from Palm Valley in 1983 and oil and gas production from Mereenie commenced in the following year. Up to five conventional petroleum systems are present in the Amadeus Basin, including the Ordovician system that hosts the Mereenie and Palm Valley fields. Three of the other four petroleum systems are Neoproterozoic in age and the fourth is Neoproterozoic to Cambrian. A variety of structural and stratigraphic traps are present within the basin. Recent developments by Central Petroleum in the Amadeus Basin include the development of the Surprise oil field in 2014, and the commencement of gas production from the Dingo field in December 2015.

The Amadeus Basin also has considerable unconventional potential, including shale gas and oil in the Horn Valley Siltstone, and tight gas in the Pacoota and Stairway sandstones.

<sup>33</sup> For details, please see <http://www.abc.net.au/news/2016-09-12/nt-government-introduces-fracking-moratorium/7843502>

## A4. Price

- Until 2011-12, wholesale gas prices in EA varied from as low as ~AUD2.50/GJ in Qld (early CSG contracts) to ~AUD3.40/GJ in the Otway and close to AUD4/GJ for supply from Cooper and Gippsland basins.
- Since this period the combination of LNG price-pull influences and supply cost-push influences have given rise to a step change in prices. LNG prices of approximately 0.15 x JCC ex Gladstone have set a new price marker - the LNG netback at Wallumbilla (LNG less transmission, liquefaction and other cost), which varies with exchange rate and USD denominated Japanese Crude Cocktail ("JCC") based oil prices. The Wallumbilla netback is essentially the upper economically-sustainable limit of the purchase price of third party gas. This price has been as high as AUD11/GJ netback to Wallumbilla historically but is presently closer to AUD4/GJ on a full cost basis and closer to AUD7 on a marginal cost basis.<sup>34</sup>
- In addition to LNG price-pull, cost-push pressures (addressed above) have caused the cost of new production to move rapidly towards AUD5-6+/GJ delivered Wallumbilla.
- These combined influences have caused prices to move toward AUD8/GJ at Wallumbilla in recent history; with oil price linkage a new feature.
- Future prices (beyond 2018) will depend on movements in oil price, exchange rate and demand and supply forces. On a Reference case basis Core believes prices will be in the range of AUD7-8 ex Wallumbilla, close to AUD7 ex Moomba and in the range AUD7-8 ex Longford.
- Oil price linkage with floors and ceilings are expected to be a feature in contracts with retailers and fixed price, CPI escalation contracts with industrial and GPG customers.

<sup>34</sup> Marginal cost here refers to all go-forward operating and capital costs associated with delivering sales gas from Wallumbilla and processing this ready for shipment as LNG. Marginal cost will excludes all sunk capital costs associated with liquefaction and export as well as delivering gas from Wallumbilla to the export facilities (where pipelines are not owned by third parties).

Figure A4.1 Existing Domestic Contract Prices | Ex-field Weighted Average (Core Estimates)

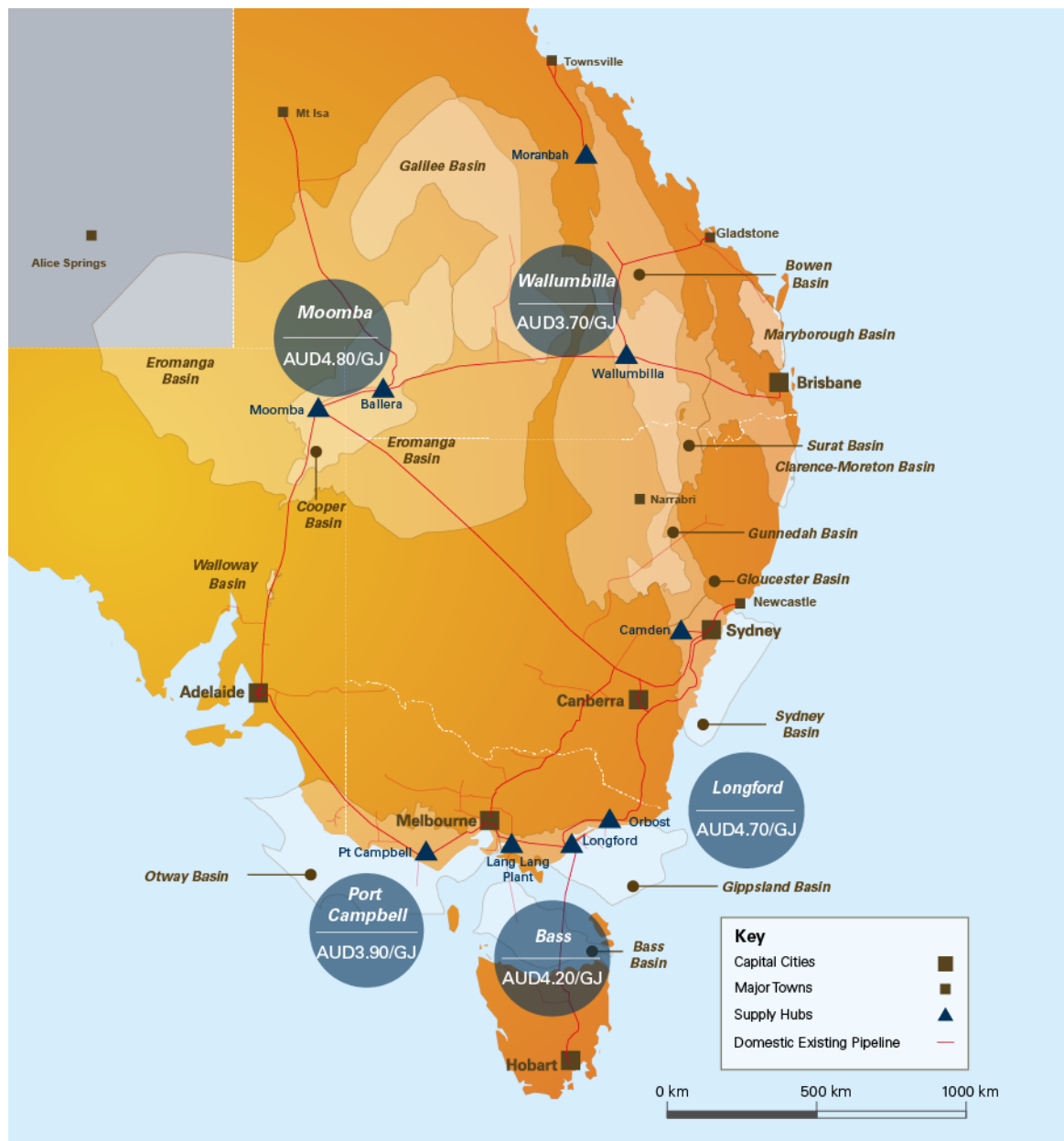
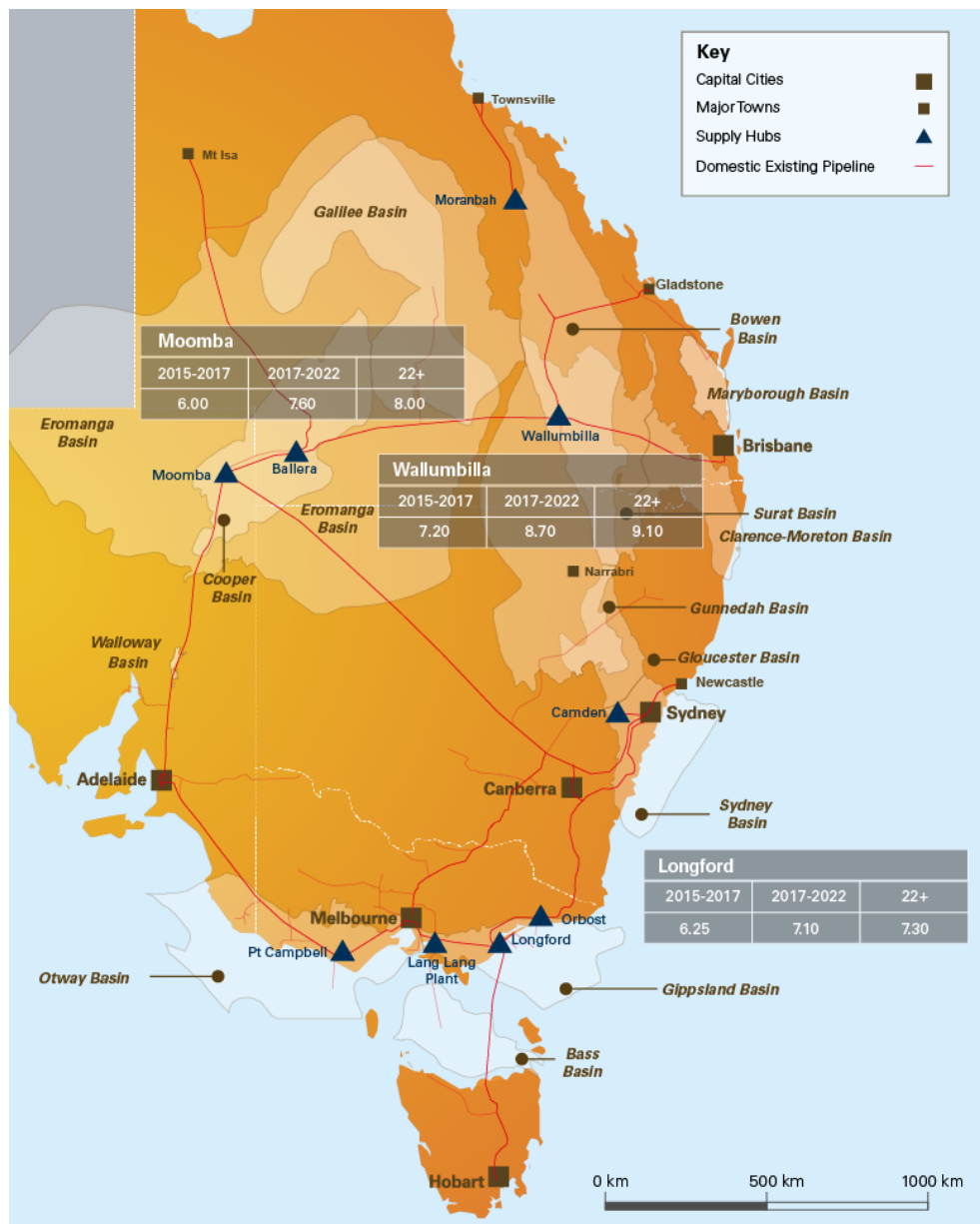


Figure A4.2 Projected Wholesale Prices | AUD/GJ



Assumptions that underpin the projected wholesale prices illustrated above include:

- Projected Dated Brent to rebound to USD70/bbl in 2023
- Assumed long term USD to AUD exchange rate of 1:0.72
- Wallumbilla: Assumed LNG oil price linkage of approximately 15% and AUD4.00/GJ of liquefaction and transmission cost, netback from Gladstone
- Moomba: Assumed AUD1.00/GJ transmission cost, netback from Wallumbilla
- Longford: Assumed oil linkage of 7.5%

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