Shale Gas Prospectivity Potential

Prepared for:

Australian Council of Learned Academies (Acola)

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1 Executive Summary

The 19 potential Shale Gas Plays in Australia with very variable rock type have been screened by AWT to be classified as a Shale Gas Play and Prospective resource numbers have been calculated for each of these plays. They range in age from Paleoproterozoic (1600+ million years ago (ma)) to Cretaceous (150 ma). The extent of the Plays range from 150 km$^2$ to 145,000 km$^2$ and are widely scattered across the Australian continent. The size of Australia, with the identification so far of 19 Shale Gas Plays, is similar in overall size and number of plays to the US, where at least 33 separate Shale Gas Plays have been discovered, suggesting that the current analysis is not unreasonable. The organic source material ranges from marine Type I through to terrestrial Type III which in many cases is different from the Shale Gas Plays in North America, which are almost entirely marine source rocks (Type I / II).

The REM Shale Gas Play in the Cooper Basin is considered by AWT to be the most advanced play in Australia, the source rock sequences in the active Cooper Basin petroleum system, may be commercially developed in a gradual way by the major operators in the basin through the extensive gas gathering system already in place. By comparison, many of the other basins are quite remote and, should exploration prove a viable gas potential, it will take many years to mature and transport to a market.

Nevertheless, large companies are positioning themselves to secure large gas resources for the future and there is potential to create significant acreage value increase by discovering large contingent resource volumes. We consider Australia to be a good place to carry out this type of exploration and development, given small population concentrated in coastal cities, tolerance of mining in general. Fracture stimulation could be more easily carried out in remote areas where there is little effect on community. The country is developing a network of gas pipelines to major LNG ports.
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2 Scope

Australian Council of Learned Academies (Acola) requested that AWT International Pty Ltd (AWT) undertake an assessment of likely shale gas resources in Australia based on proprietary and publicly available information. AWT has provided for each of the major basins a Best Estimate (P50) of Prospective Resource numbers. AWT has also provided both wet gas area and dry gas area and hydrocarbon volumes for each of 19 shale gas plays (Figure 1) screened in the AWT Shale Gas Atlas 2012. AWT has also provided 19 maps (Appendix 1) of the shale pod distribution of the wet and dry gas areas as we have described them, with existing infrastructure.
3  DEFINITION OF A SHALE GAS PLAY

3.1  SPE guideline for a Shale Gas Play

SPE has defined the terminology for the Shale Gas Play as described below:

"Shale gas is produced from organic-rich mudrocks, which serve as a source, trap, and reservoir for the gas. Shales have very low matrix permeabilities (hundreds of nanodarcies), requiring either natural fractures and/or hydraulic-fracture stimulation to produce the gas at economic rates. Shales have diverse reservoir properties, and a wide array of drilling, completion, and development practices are being applied to exploit them. As a result, the process of estimating resources and reserves in shales needs to consider many different factors and remain flexible as our understanding evolves.

Shales are complex rocks that exhibit submillimeter-scale changes in mineralogy, grain size, pore structure, and fracturing. In thermogenic shale gas reservoirs (like the Barnett shale in the US and the REM play in Australia), the organic matter has been sufficiently cooked to generate gas, which is held in the pore space and sorbed to the organic matter. In biogenic shale gas reservoirs (like the Antrim shale in the US and the Toolebuc Fm in Australia) the organic matter has not been buried deep enough to generate hydrocarbons. Instead, bacteria that has been carried into the rock by water has generated biogenic gas that is sorbed to the organics. TOC (Total Organic Content) values are high in biogenic shales (often > 10 wt%), but relatively low (> 2 wt%) in thermogenic shales where most of the TOC has been converted to hydrocarbons.

A common feature of productive thermogenic shale gas plays is brittle reservoir rock containing significant amounts of silica or carbonate and “healed” natural fractures. Relative to more clay-rich rock, the brittle rock shatters when hydraulically fracture stimulated, which maximizes the contact area. Thermogenic shales are often referred to as “fracturable” shales instead of “fractured” shales. In contrast, biogenic shales are commonly less brittle and rely on the existence of open natural fractures to provide conduits for water and gas production."

Shale gas reservoirs are often the source rocks for conventional gas and oil accumulations (Figure 2). However, based on a review of the characteristics of shale gas plays in the US, it has been realised that there is a wide variety in many of the play parameters beyond the reservoir being fine-grained and of low permeability.
4  METHODOLOGY FOR DEFINING SHALE GAS PLAY

4.1  Shale Gas Play Screening Criteria

The evaluation of the potential Shale Gas Plays for each basin takes place in 4 steps:

1. Regional source rock assessment (degree of thermal maturity)
2. Play screening criteria
3. Play description
4. Resource assessment

After initial evaluation of the regional data to identify the mature source rocks in the basin (Step 1), a Shale Gas Play screening test (Step 2) is applied to each of these units. The screening test compares the data available against common factors in successful US Shale Gas Plays:

- Lithotype - fine-grained lithology with evidence of sufficient TOC concentration
- Thickness - greater than 30m (100 ft)
- Maturity - Wet Gas window 0.8 - 1.2 VRo and Dry Gas window greater than 1.2 VRo
- Moderate to low clay content less than 40% with very low mixed layer content
- Brittle composition (low Poisson’s ratio and high Young’s Modulus)
- Has a rock fabric (natural fractures) that enhances productivity
- High lateral continuity of reservoir conditions
- The organic matter is not oxidised

Where data is unavailable for a potential play, an evaluation of the regional information was made to decide if it is likely that the screening condition can be met.

In the US, a storage capacity that exceeds $3 \text{ m}^3/\text{tonne}$ (100 scf/ton) is considered a critical factor for commercial success and a lot of effort and expenditure is put into accurately evaluating this parameter. However, due to the lack of Shale Gas exploration drilling and appropriate measurements to calculate storage capacity in the Australian Plays this parameter cannot be used as a screening criteria at this time.

AWT has examined 26 Basins in onshore Australia and have identified 19 individual Shale Gas Plays (Table 1) that meet the above screening criteria. Section 5.1 shows a listing of screened basin that did not fit the current criteria to be included as Shale Gas plays. Individual maps with Shale Gas Play extents and existing infrastructure are attached as an appendix in this report. Reference listing has also been provided for each of the Shale Gas Plays.
5 **Shale Gas Play Prospective Resource Estimates**

AWT has examined 26 Basins in onshore Australia and have identified 19 individual Shale Gas Plays (Table 1) that meet the above screening criteria. High level overview was undertaken to identified these 19 Shale Gas Plays, with increased exploration and mapping in many of these basins, additional Shale Gas Plays may become known.

Table 1. Prospective Resource estimates of Shale Gas Plays that meet screening criteria.

<table>
<thead>
<tr>
<th>Basin</th>
<th>Play</th>
<th>Gas Pod</th>
<th>Area (km²)</th>
<th>Best Estimate Recoverable Resource (Tcf)</th>
<th>BOE volume (MMbls)</th>
<th>BOE/km²</th>
<th>Recoverable Resource bcf/km²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amadeus</td>
<td>Horn Valley</td>
<td>Dry</td>
<td>7,267</td>
<td>16</td>
<td>2777</td>
<td>0.38</td>
<td>2.19</td>
</tr>
<tr>
<td>Beetaloo</td>
<td>Kyalla</td>
<td>Dry</td>
<td>898</td>
<td>3</td>
<td>467</td>
<td>0.46</td>
<td>2.62</td>
</tr>
<tr>
<td></td>
<td>Velkerri</td>
<td>Dry</td>
<td>6,092</td>
<td>16</td>
<td>2796</td>
<td>0.46</td>
<td>2.62</td>
</tr>
<tr>
<td>Bonaparte</td>
<td>Milligans</td>
<td>Dry</td>
<td>2,752</td>
<td>6</td>
<td>1090</td>
<td>0.28</td>
<td>1.60</td>
</tr>
<tr>
<td>Bowen</td>
<td>Black Alley</td>
<td>Dry</td>
<td>51,252</td>
<td>97</td>
<td>16979</td>
<td>0.33</td>
<td>1.89</td>
</tr>
<tr>
<td>Canning</td>
<td>Goldwyer</td>
<td>Wet</td>
<td>147,305</td>
<td>409</td>
<td>71306</td>
<td>0.48</td>
<td>2.77</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dry</td>
<td>139,321</td>
<td>387</td>
<td>67444</td>
<td>0.48</td>
<td>2.77</td>
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<tr>
<td></td>
<td>Laurel</td>
<td>Wet</td>
<td>48,285</td>
<td>106</td>
<td>18459</td>
<td>0.38</td>
<td>2.19</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dry</td>
<td>28,704</td>
<td>63</td>
<td>10973</td>
<td>0.38</td>
<td>2.19</td>
</tr>
<tr>
<td>Carnarvon</td>
<td>Byro Group</td>
<td>Dry</td>
<td>6,162</td>
<td>9</td>
<td>1575</td>
<td>0.25</td>
<td>1.46</td>
</tr>
<tr>
<td>Clarence-Moreton</td>
<td>Koukandowie</td>
<td>Dry</td>
<td>4,407</td>
<td>11</td>
<td>1901</td>
<td>0.43</td>
<td>2.48</td>
</tr>
<tr>
<td></td>
<td>Raceview</td>
<td>Dry</td>
<td>4,407</td>
<td>10</td>
<td>1677</td>
<td>0.38</td>
<td>2.19</td>
</tr>
<tr>
<td>Cooper</td>
<td>Roseneath, Epsilon,</td>
<td>Wet</td>
<td>3,604</td>
<td>14</td>
<td>2385</td>
<td>0.66</td>
<td>3.79</td>
</tr>
<tr>
<td></td>
<td>Murterree (REM)</td>
<td>Dry</td>
<td>9,106</td>
<td>35</td>
<td>6026</td>
<td>0.66</td>
<td>3.79</td>
</tr>
<tr>
<td>Eromanga</td>
<td>Toolebuc</td>
<td>Dry</td>
<td>93,263</td>
<td>82</td>
<td>14244</td>
<td>0.15</td>
<td>0.87</td>
</tr>
<tr>
<td>Georgina</td>
<td>Arthur Creek</td>
<td>Dry</td>
<td>14,433</td>
<td>50</td>
<td>8731</td>
<td>0.51</td>
<td>2.91</td>
</tr>
<tr>
<td>Gunnedah</td>
<td>Watermark</td>
<td>Dry</td>
<td>8,631</td>
<td>13</td>
<td>2185</td>
<td>0.25</td>
<td>1.46</td>
</tr>
<tr>
<td>Maryborough</td>
<td>Cherwell</td>
<td>Dry</td>
<td>3,264</td>
<td>7</td>
<td>1289</td>
<td>0.41</td>
<td>2.33</td>
</tr>
<tr>
<td>McArthur</td>
<td>Barney Creek</td>
<td>Wet</td>
<td>2,867</td>
<td>7</td>
<td>1304</td>
<td>0.51</td>
<td>2.91</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dry</td>
<td>158</td>
<td>0.4</td>
<td>72</td>
<td>0.51</td>
<td>2.91</td>
</tr>
<tr>
<td>Otway</td>
<td>Eumeralla</td>
<td>Dry</td>
<td>4,109</td>
<td>9</td>
<td>1563</td>
<td>0.38</td>
<td>2.19</td>
</tr>
</tbody>
</table>
5.1 Basins that didn't meet Screening Criteria

Whilst screening the onshore sedimentary basins in Australia, numerous formations did have some characteristics of a potential Shale Gas Play. However, to be classified as a Shale Gas Play, they had to meet all screening criteria outlined in section 3.1. The three main reasons why the potential play didn't meet the criteria are outlined below and summarised in Table 2.

- Lack of sufficient thickness (criteria to be reached >30m of formation).
- Formation lacks thermal maturity greater than 0.8 Vitrinite Reflectance (VRo). However, sometimes there was limited data and no contoured VRo maps to define the Play extent. In these cases, a number of other methods were used including, though not limited to, minimal thermal maturity data, depth contours, geothermal gradients and ideas expressed in publications.
- A lack of available data to make an informed decision on Shale Gas Play parameters.

It should be noted that with increased data from exploration, some of these basins could possibly meet the screening criteria to be classified as a Shale Gas Play.

Table 2. Basins that didn't meet Screening Criteria.

<table>
<thead>
<tr>
<th>Basin</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adavale</td>
<td>Classified as Tight Sand stratigraphic play</td>
</tr>
<tr>
<td>Arckaringa</td>
<td>Insufficient maturity data available, to determine if shales have potential</td>
</tr>
<tr>
<td>Darling</td>
<td>Data from cores shows the shale sections appear to be heavily oxidised thus TOC preservation is poor</td>
</tr>
<tr>
<td>Drummond</td>
<td>Evidence from Mooga 1 the most complete section available indicates the Drummond Basin sediments have low TOC &lt; 0.5% – no source rocks. This is backed up by regional descriptions of the Drummond Basin as being deposited in shallow water and oxidizing environments.</td>
</tr>
<tr>
<td>Galilee</td>
<td>Toolebuc Formation included in Eromanga Basin</td>
</tr>
<tr>
<td>Gippsland</td>
<td>Lack of sufficient older lacustrine shale’s of the Emperor Subgroup maturity extending onshore.</td>
</tr>
<tr>
<td>Officer</td>
<td>Is classified as having a Tight Sands Gas play as opposed to a Shale Gas play</td>
</tr>
<tr>
<td>Simpson</td>
<td>Unknown at this stage, but appears to be due to the absence of laterally thick shale sequences</td>
</tr>
<tr>
<td>Surat</td>
<td>Insufficient maturity and thickness in the Evergreen Fm</td>
</tr>
<tr>
<td>Sydney</td>
<td>TOC data extremely lean and extent of Shale unknown with respect to depth.</td>
</tr>
<tr>
<td>Location</td>
<td>Details</td>
</tr>
<tr>
<td>-----------</td>
<td>---------</td>
</tr>
<tr>
<td>Warburton</td>
<td>Currently no known indigenous source rocks; gas and oil from down dip Cooper Basin source rocks.</td>
</tr>
<tr>
<td></td>
<td>Wells in area currently targeting shallower CSG plays</td>
</tr>
</tbody>
</table>
6  **Methodology for Calculating Prospective Resource**

6.1  **Best Estimate Calculation**

The method of resource estimation employed by AWT has been guided by industry practices in the US. The calculation has been undertaken where ranges for Shale Gas Play parameters were developed by reviewing well, seismic, geological data, and US analogues. A Best Estimate approach to the calculation of Prospective Resources for the 19 Shale Gas Plays identified by AWT has been undertaken using the following calculation in Table 3 (parameters from the REM Wet Gas play in the Cooper Basin are shown in this calculation).

<table>
<thead>
<tr>
<th>Table 3. Best Estimate calculation of Prospective Resource</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Parameter</strong></td>
</tr>
<tr>
<td>Area km²</td>
</tr>
<tr>
<td>Height m</td>
</tr>
<tr>
<td>Bulk Rock Volume</td>
</tr>
<tr>
<td>Shale Density</td>
</tr>
<tr>
<td>Mass of shale</td>
</tr>
<tr>
<td>Net to Gross of total thickness</td>
</tr>
<tr>
<td>Total Gas capacity</td>
</tr>
<tr>
<td>Total Gas capacity</td>
</tr>
<tr>
<td>Total gas in place</td>
</tr>
<tr>
<td><strong>Total gas in place (TGIP)</strong></td>
</tr>
<tr>
<td>Recovery factor</td>
</tr>
<tr>
<td>Recoverable Volume</td>
</tr>
<tr>
<td>Barrels of Oil Equivalent (BOE) volume</td>
</tr>
</tbody>
</table>

A recovery factor was applied to the best estimate in-place volumes to estimate the recoverable volume of hydrocarbon from each reservoir (Table 1). The recovery factor used was determined by analysing production data from US Shale Gas Plays. It was determined that an average recovery factor of 15% was the best fit for the majority of production from Shale Gas Plays.
6.2 **SPE guideline for Best Estimate**

The input parameters for each Shale Gas Play assessment were selected using the SPE 2011 Guidelines of the "Best Estimate". The SPE Guideline for Best Estimate is outlined below.

*With respect to resource categorisation, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.*

6.3 **Justification for Best Estimate calculation**

At this early stage in the evaluation of Australian Shale Gas Plays, estimates of the Prospective Resource have high uncertainty, as plays are as not yet adequately explored. Additionally the ranges of uncertainty are too high and the high and low sides values would be unrealistic using a Monte Carlo calculation.
7 SPE Definition of Prospective Resource

7.1 SPE Guideline for Prospective Resource

The SPE Guideline for Prospective Resource is outlined below.

Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared.

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

A project may have recoverable quantities in several resource classes simultaneously. As barriers to development are removed, some resources may move to a higher classification. One of the primary distinctions between resources and reserves is that while resources are technically recoverable, they may not be commercially viable. Reserves are always commercially viable and there is intent development them.
Potential Shale Gas Play sweet spots are plays that have an alignment of positive criteria, based on a review of the characteristics of commercial Shale Gas Plays in the US.

Shale Gas success is dependent on finding the most prospective areas, or the “sweet spots,” and aligning the well for maximum borehole exposure to these zones. In Shale Gas Plays this means placing the well in the zones most conducive to fracturing. This requires a thorough understanding of the shale gas reservoir characteristics. Aiming for the middle is rarely a successful strategy, as shales can have significant variance in thickness and composition.

Fluid composition and reservoir pressure are essential elements in the assessment of Shale Gas Plays. The sweet spot part of the Shale Gas Play is often defined by the intersection of high reservoir pressure with the right gas-oil ratio. Review of US Shale Gas Plays, indicates that operators are utilising production data to validate the sweet spot, however as no Australia Shale Gas Plays currently have production data using this method isn’t an option in identifying Shale Gas sweet spots in Australian Basins.

TOC and porosity are also key indicators of Shale Gas Play sweet spot zones. TOC sample data and log curve data from previously drilled wells in the basin are needed to calculate a TOC-calibrated model to indentify these zones. Limited open file TOC sample data is available in Australia, however in many basins this data is extremely sparse because of lack of exploration or that current exploration in the basin has to date not targeted Shale Gas Plays.

The REM Shale Gas Play is the only play that has sufficient information to be classified as being a Shale Gas Play sweet spot. The REM is sufficiently mature for hydrocarbon generation, with laterally extensive thick intervals and a lithotype that is organic-rich (usually more than 2% organic matter) with low clay content.

The play is in an established hydrocarbon province with significant existing infrastructure. It has direct pipeline access to the gas markets of NSW, QLD and SA, and hence potential for domestic or export use and off all the prospective shale gas basins in Australia, is likely to be the most readily developed.

The brittleness and natural fracture network are known to be critical to the commercial success of a Shale Gas Plays in the US. Recent information on fracture mapping by Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) 2012 identified an orthogonal natural fracture system oriented N-S and E-W in the Nappamerri Trough, Cooper Basin that can assist in orientating future horizontal wells and fracture stimulations.

These natural fracture systems may have been naturally enhanced by the mineralogy of the clays in these lacustrine shales. Beach Energy has publicly discussed the mineral composition of the shales which are high in silica and illite and absence of swelling clays which collectively are conducive to brittleness and ideal for fracture stimulation. Beach Energy have successfully performed 7 fracture stimulations and flowed gas from the REM play with their Holdfast 1 well.
9 **Potential Shale Gas Play Roadblocks**

The Australian domestic gas market is relatively small. Coal Seam Gas (CSG) resources are now so large that significant infrastructure is being built at Gladstone (QLD) on the east coast of Australia to feed LNG into a growing world market coming online in 2014/2015. Shale Gas has similar potential in Australia. Australia is in an ideal place in which to develop this type of resource, however potential hazards exist which could impact the development of Shale Gas exploration in Australia. These roadblocks have been identified by AWT and are listed below are not ranked in any particular order.

- Several basins are extremely isolated in central Australia
- No established infrastructure, including but not limited to, pipelines, processing plants road and/or rail infrastructure
- Close proximity of Shale Gas Play to capital cities and major towns which may present landowner and drilling issues relating to fraccing operations
- Native Title and possible environmental issues
- Water availability, use and disposal in drilling and fracturing operations
- Depth of target Shale Gas Plays increasing exploration and development costs
- Commercialisation costs much greater when compared to US, due to exploration and development costs
- Extent of Shale Gas Play is under tenure and is predominantly held by a few key players that are focussed on Conventional or CSG exploration. They may be unlikely to be receptive to farm-in offers though the possibility exists that they would be willing to farm out shale gas activities to allow them to remain focussed on other operations
- Lack of available equipment, specific to Shale Gas exploration (i.e. large fraccing spreads)
10 CONCLUSIONS

More work is required to quantify the areas identified as potential Shale Gas Plays having suitable depth, maturity, lithology, and thicknesses. Exploration is the key, practically drilling and coring of these shales is required to accurately define the lateral extent and limits of any of these potential plays within Australia.

To commercialise, Shale Gas Plays require fracture stimulation. The effectiveness of fracture stimulation depends on the reservoir’s brittleness. If the reservoir contains a high quantity of ductile materials like clay, mudstones and tuff, it may make fractures difficult to generate. The design effectiveness and commercial prospects of fracture stimulating for the 19 identified Shale Gas Plays requires further investigation.

Lack of infrastructure will mean that even a successful play will require a very long time to achieve a reasonable gas volume to be developed and transported to market. To date in many of the Shale Gas plays identified there is little to no published desorption tests from core or cuttings and no published tight rock analyses. This information would greatly increase the level of understanding and reduce the uncertainty. Seismic across some of the basins is also minimal, though is not required for early exploration and proof of concept.

The Shale Gas Plays screened by AWT located within the Cooper, Perth, Canning and Bowen Basins are considered the most prospective plays for exploration. This is based the presence of the following

- large number of well and seismic data
- hydrocarbon discoveries
- size
- locality to infrastructure and market
- relative ease of locating wells and lower cost to complete and tie wells into existing pipelines.
11 REFERENCES

11.1 GENERAL REFERENCES


11.2 AMADEUS BASIN


11.3 BEETALOO BASIN


11.4 BONAPARTE BASIN


11.5 BOWEN BASIN


11.6 CANNING BASIN


• Buru Energy ASX announcement (June 1, 2011). Canning Superbasin - Unconventional Resource Assessment.

11.7 CARNARVON BASIN


11.8 CLARENCE-MORETON BASIN


11.9 COOPER BASIN


11.10 EROMANGA BASIN


11.11 GEORGINA BASIN


11.12 GUNNEDAH BASIN


11.13 MARYBOROUGH BASIN


11.14 McARTHUR BASIN


11.15 OTWAY BASIN


• Boult, P.J., Ramamoorthy, R., Theologou, P.N, East, R.D, Drake, A.M and Neville, T., 1999. Use of nuclear magnetic resonance and new core analysis technology for determination of gas


### 11.16 PEDIRKA BASIN


11.17 PERTH BASIN


• Skinner, J. 1991. The tectonic elements of the Perth basin. SAGASCO Resources Ltd. Structure Map
12 DISCLAIMER

AWT INTERNATIONAL has relied on publicly available data to compile the Shale Gas Plays. Information consisted of seismic data, well completion reports, geological and geochemical studies, and published technical papers and studies. These were compiled and written by various industry and government bodies. The material was reviewed for its quality, accuracy and validity and was captured and modified to suit this basin by basin analysis of Shale Gas Plays. However, the level of review of such information does not amount to an audit, verification or due diligence, save to the extent necessary to satisfy ourselves that it is reasonable for us to rely on that information. No warranty can be given that this report has analysed all parameters which a more extensive examination might reveal. We give no warranty that reliance upon the report will accomplish any particular result. However, the opinions and statements in this report are made in good faith and in the belief that such opinions and statements are not misleading.

This report has been prepared based on information available up to and including 30 November 2012.

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FIGURES
SCHEMATIC CROSS-SECTION
Shale Gas Play and Continuous Gas Play Schematic (USGS)

Modified from EIA, US Energy Information Administration figure
APPENDICES
Shale Gas Plays with Infrastructure
Laurel Shale Gas Play - Canning Basin

PROJECTION ZONE: WGS84
1:6,600,000
1 cm = 66 km

Author: KR    Date: 18 DEC 2012
Drafted: GH    Date: 18 DEC 2012    Drawing No.: J7728
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