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TO: The Manager, Company Announcements ASX Limited

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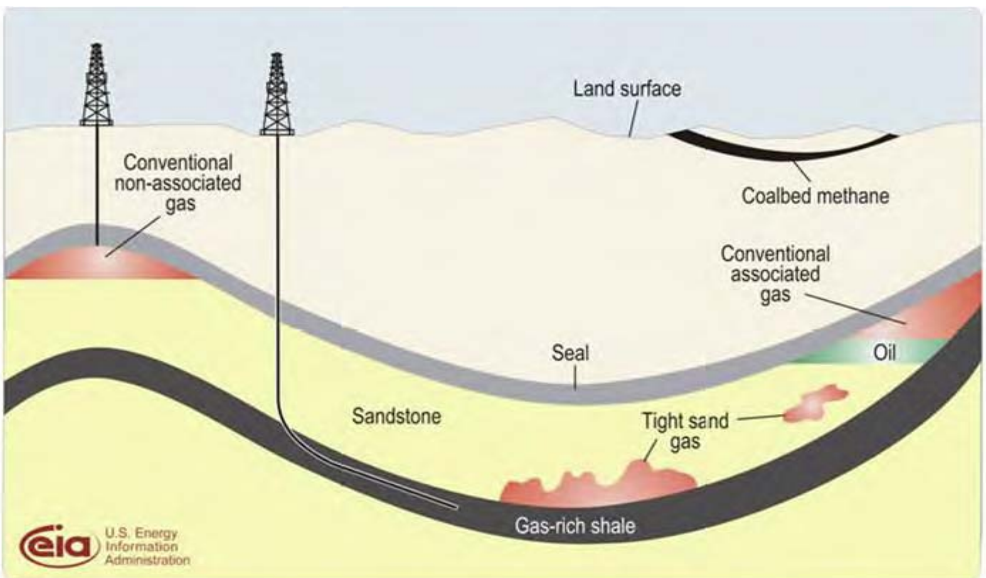
INDEPENDENT AMADEUS UNCONVENTIONAL GAS AND OIL APPRAISAL- MEAN PROSPECTIVE RECOVERABLE RESOURCES 26 TCFG & 1 BN. BBLS

Central Petroleum Limited (ASX:**CTP**) ("**Central**"), as Operator, has pleasure in providing the results of an unconventional gas and oil assessment of the Lower Larapinta Group sediments of Central's Amadeus Basin permit and application areas by DSWPET Pty Ltd and MBA Petroleum Consultants, independent Australian experts in unconventional resource assessments.

"The resource estimates for these plays will require a significant amount of more seismic, drilling and testing to potentially confirm or re-define" said John Heugh, Central's Managing Director today, "but these results, by one of Australia's leading consultancies in the field of unconventional resources, provides the Company with a sound basis upon which to attract bigger companies into productive joint ventures". The Company has previously announced long term ambitions to enter into GTL, LNG or other value adding on a large scale.

Unconventional resources are also referred to as Basin centred or continuous hydrocarbon accumulations and do not rely upon either stratigraphic or structural closures to trap gas or oil, the host rock being simply too "tight" to allow hydrocarbons to escape in commercial volumes without horizontal drilling and "fraccing". Usually the permeabilities of such host shales and tight gas sands are less than 0.1 milliDarcies.



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Examples in North America are the Barnett Shale now with total recoverable resources of 44 TCF gas and the Bakken Shale 4 Billion BBLS oil. The value of these unconventional hydrocarbon accumulations is reflected in the billions of dollars being spent by the majors such as Shell, BP and Exxon-Mobil to acquire these new plays.
Continuous gas and or oil accumulations have only recently been examined in Australia but momentum is building in basins such as the Cooper Basin (Santos, Beach Petroleum), the Perth Basin (AWE), the Canning Basin (Buru Energy) and now with Central Petroleum Limited in the Amadeus.

The independent report assessed the *probabilistic unrisked prospective recoverable resources* (SPE) of gas and oil within four assessment units determined by maturation indices and other data as follows:

Assessment Unit	P90 "Low"	Mean	P10 "high"	Resource
Stairway Sandstone Continuous Gas AU **(3,440 km^2- 0.85 million acres)**	**1.1**	**5.1**	**10.5**	**TCFG**
Horn Valley Siltstone Continuous Gas AU **(7,395 km^2-1.83 million acres)**	**2.6**	**11.3**	**23.8**	**TCFG**
Pacoota Sandstone Continuous Gas AU **(3,440 km^2-0.85 million acres)**	**2.4**	**9.8**	**19.7**	**TCFG**
Total Gas all gas Aus **(14,275 km^2-3.53 million acres)**	**6.1**	**26.2**	**54.0**	**TCFG**
Horn Valley Continuous Oil AU **(5,436km^2-1.34 million acres)**	**0.214**	**1.061**	**2.3**	**Billions of BBLS**

In summary the Probabilistic Mean Unrisked Prospective Recoverable (unconventional) Resource for the Lower Larapinta Group in the Amadeus Basin within the Company's acreage is estimated to be approximately 26 TCF Gas and 1 billion BBLS of oil. As the distribution of commercially viable resource is difficult to predict until more data is to hand, the "high" or P10 quantifications are based on a maximum of only 30% of the potential play surface area, which although not technically fully "risked" does impute a degree of conservatism to the numbers quoted.

Central retains an undivided 100% interest in the acreage the subject of this report.

John Heugh

Managing Director
<u>Central Petroleum Limited</u>

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NOTICE: The participating interests of the relevant parties in the respective permits and permit applications which may be applicable to this announcement are:

- *EP-82 (excluding the Central subsidiary Helium Australia Pty Ltd ("HEA") and Oil & Gas Exploration Limited ("OGE") (previously He Nuclear Ltd) Magee Prospect Block) - HEA 100%*
- *Magee Prospect Block, portion of EP 82 – HEA 84.66% and OGE 15.34%.*
- *EP-93, EP-105, EP-106, EP-107, EPA-92, EPA-129, EPA-131, EPA-132, EPA-133, EPA-137, EPA-147, EPA-149, EPA-152, EPA-160, ATP-909, ATP-911, ATP-912 and PELA-77 - Central subsidiary Merlin Energy Pty Ltd 100% ("MEE").*
- *The Simpson, Bejah, Dune and Pellinor Prospect Block portions within EP-97 – MEE 80% and Rawson Resources Ltd 20%.*
- *EP-125 (excluding the Central subsidiary Ordiv Petroleum Pty Ltd ("ORP") and OGE Mt Kitty Prospect Block) and EPA-124 – ORP 100%.*
- *Mt Kitty Prospect Block, portion of EP 125 - ORP 75.41% and OGE 24.59%.*
- *EP-112, EP-115, EP-118, EPA-111 and EPA-120 - Central subsidiary Frontier Oil & Gas Pty Ltd 100%.*
- *PEPA 18/08-9, PEPA 17/08-9 and PEPA 16/08-9 - Central subsidiary Merlin West Pty Ltd 100%.*
- *EPA-130 - MEE 55% and Great Southern Gas Ltd 45%.*

Unconventional Reservoir

Resource Assessment

For the

Lower Larapinta Group

Amadeus Basin

With Attachments by AWT/MBA Petroleum Consultants

BY

DSWPET

January 2011

1 Executive Summary

Four new unconventional gas plays have been identified in Lower Larapinta Group of the Amadeus Basin and their prospective resources estimated. The total prospective resource for these plays is 1.0 Billion BBLS Oil and 26 TCF of Gas.

The plays and their mean prospective resource estimates are:

1. Horn Valley Shale Gas - 11.3 TCF
2. Horn Valley Shale Oil - 1.1 Billion BBLS
3. Pacoota Tight Gas -9.8 TCF
4. Stairway Tight Gas- 5.1 TCF

There is evidence of other petroleum systems in the Amadeus Basin, however there was insufficient data available to make an assessment of the unconventional resource potential of these systems. Further work targeting the Giles and Goyder Formations is recommended.

Until recently the presence of unconventional continuous gas and oil accumulations in tight reservoirs has not been recognized in the Australian oil and gas industry. In North America the presence of these accumulations, which are outside conventional structural closure and in reservoirs with very low permeability, is now proven beyond doubt as has their commercial significance. Examples are the Barnett Shale now with total recoverable resources of 44 TCF gas and the Bakken Shale 4 Billion BBLS oil. The value of these unconventional hydrocarbon accumulations is reflected in the billions of dollars being spent by the majors such as Shell, BP and Exxon-Mobile to acquire these new plays.

The assessment methodology is based on the methodology used by the United States Geological Survey (USGS) for similar unconventional plays in the USA. This methodology, which uses Petroleum systems and subdivides them into assessment units, allows regional assessments to be made. Given the immature nature of the unconventional play development in Australia, analogs from the US are used to constrain the input ranges used to calculate the technically recoverable resource.

The Lower Larapinta Group Total Petroleum System has been subdivided into 4 possible unconventional assessment units (AUs) or plays:

1. Horn Valley - Continuous Gas AU - 7395 Km^2 (1.83 mill acres)
2. Horn Valley - Continuous Oil AU - 7031 Km^2 (1.74 mill acres)
3. Stairway Continuous Gas AU - 3440 Km^2 (0.85 mill acres)
4. Pacoota - Continuous Gas AU - 3440 Km^2 (0.85 mill acres)

Whilst large play areas are indicated, it is unlikely that the majority of these areas will be commercial. In North America, commercial production occurs where “sweet spots” exist, much of the unconventional commercial production in North America being defined by natural fracture distribution and or rock mechanical properties. Even if this were also the case in the Amadeus Basin, there is insufficient information currently available to determine the area of likely production. Thus the upside area of production for continuous oil or gas used to produce “High” or P10 prospective recoverable resources is capped at 30% of the total play or AU area, with reduced areas being used to produce mean and “Low” or P90 prospective recoverable resources. This approach is probably more conservative than other reports in the public domain which have used a single area for the resource estimates.

Probabilistic estimates of the prospective, technically recoverable resources for the 4 unconventional assessment units or plays in the Lower Larapinta of the Amadeus Basin are:

AU	P90 Low	Mean Mean	P10 High	Resource Classification
Stairway Continuous Gas AU	1.1	5.1	10.5	Prospective (Recoverable) Resource TCF
Horn Valley Continuous Gas AU	2.6	11.3	23.8	Prospective (Recoverable) Resource TCF
Pacoota Continuous Gas AU	2.4	9.8	19.7	Prospective (Recoverable) Resource TCF
Total Gas all gas AUs	11.1	26.2	45.7	
Horn Valley Continuous Oil AU	0.207	1.14	2.5	Prospective (Recoverable) Resource Billions of BBLS

In summary the probabilistic, mean, unrisked, unconventional, prospective, technically recoverable resource for the Lower Larapinta Group in the Amadeus Basin is estimated to be approximately 26 TCF Gas and 1 billion BBLS of oil.

These resources are comparable in size to analog plays in the US such as the Bakken Shale Oil - 4 Bill BBLS Oil and the Barnett Shale Gas - 50 TCF

Given the paucity of data available over the large areas involved in the study, the resource estimates for these plays will require significantly more seismic, drilling and testing before they can be redefined to the contingent resource or reserve categories.

2 Contents

Figures

3 Definition of Unconventional Hydrocarbon Accumulations

Unconventional hydrocarbon accumulations are spatially extensive accumulations of gas and or oil that exist outside hydrodynamic (buoyancy) traps in reservoirs that have permeabilities less than 0.1md. These reservoirs are often the source rocks for conventional gas and oil accumulations. They generally occur towards the centre of the basins at relatively high thermal maturities (VRo > 1.2) and are sometimes referred to as Basin Centred accumulations. The USGS in their published basin assessments refers to them as continuous hydrocarbon accumulations.

Habitat

Continuous or non hydrodynamic gas accumulations can be either biogenic or thermogenic. Continuous oil is thermogenic. This assessment addresses potential continuous thermogenic plays only.

Continuous gas plays occur in mature source rocks with VRo > 1.2%. Often this is toward the centre of Basins and often below 2,500 meters (8,000 ft). They are almost always associated with a continuous gas accumulation as defined by the USGS, SPE et. al. Where un- roofing of basins has occurred the depths for continuous gas accumulations can be shallower.

The habitat of thermogenic continuous gas and its spatial relationship to other forms of hydrocarbon accumulations is shown in Figure 1.

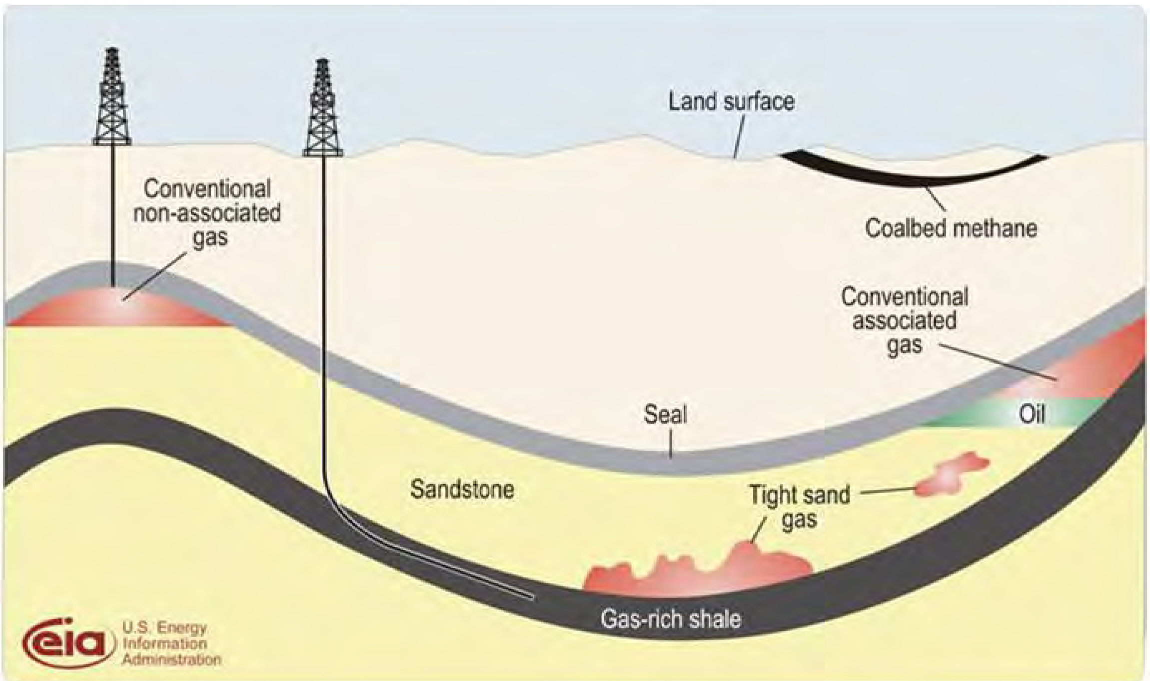


Figure 1 Habitat of continuous gas accumulations

Examples of continuous gas accumulations or plays in the US include the Mesaverde in the Green River Basins and the Barnett Shale in the Fort Worth Basin, Texas. The USGS has published resource estimates of these plays and these estimates have outlined a process which is emulated herein.

Recently, with the success of the Bakken Shale oil play in the Williston Basin, continuous oil accumulations have also been described and this play type is currently the focus of much of the exploration activity in shale reservoirs in North America. The USGS has also done a resource assessment of the Bakken play.

Continuous gas and or oil accumulations have only recently been examined in Australia but momentum is building in basins such as the Cooper Basin (Santos, Beach Petroleum), the Perth Basin (AWE), the Canning Basin (Buru Energy) and now with Central Petroleum Limited in the Amadeus Basin and Baraka Petroleum in the Georgina Basin.

Lithotypes

Lithotypes which host unconventional hydrocarbon plays include organic rich shales, siltstones, and fine grained sandstones. These organic rich Lithotypes act as both source and reservoir but can often be interbedded with non organic rich Lithotypes such as sandstones siltstones, shales and carbonates which act as reservoirs alone. They may also be gradational with carbonaceous rich Lithotypes such as coals. It is important to note that whilst all these Lithotypes are often called shale plays they have significant variances in TOC content and the way they store and produce hydrocarbons. **Thus the HIP models used and the recovery factors applied in any resource assessment must reflect the Lithotype that is being studied.**

Production from Unconventional Reservoirs

In many cases, horizontal wells and hydraulic fracturing is required to achieve commercial production. Whilst unconventional reservoirs can have attractive initial production rates they will typically decline sharply when compared to conventional gas reservoirs. However once production has stabilized they are likely to produce at a stabilized rate for long periods of time. Also experience has shown that re-stimulation often produces significant incremental reserves rather than just accelerating existing reserves production. In the Mesaverde Formation, in fields like Jonah, Pinedale and Wattenburg, infill drilling and restimulation have achieved recovery factors in the order of 80%.

4 Data Available

Data was supplied by Central Petroleum together with a number of previous exploration companies, government sources and other independent reports. Note these data do not include the many production wells in the Palm Valley and Mereenie Fields as these are within current production licences and are not released by the statutory authority. In all 12 wells have been provided which have a sufficient suite of mud logs and electric logs to enable an interpretation to be made. Regional seismic lines were also inspected to validate the structural interpretation for the top Pacoota Sandstone structure map provided by Central Petroleum. All data was loaded onto a Kingdom software evaluation platform.

In general terms the data available is scarce and in most cases doesn't target unconventional reservoirs.

MBA/AWT provided the data gathering and the review of the well data that led to the delineation of the Lower Larapinta TPS and assessment units. Also they provided the subdivision and thickness calculations of the Lithotypes. Their report is attached .

5 Assessment Methodology

The Assessment methodology used herein is based on the USGS methodology for resource assessment of unconventional (Continuous or Basin Centred) resources. In these assessments the configuration of a total petroleum system (TPS) is described and assessment units (AU's) are used for further subdivision of the TPS. Figure 2 shows a schematic of a TPS and the distribution of the AU's within that TPS.

Note there is no continuous oil assessment unit in this model of a TPS. The presence of a continuous oil assessment unit (which may surround the continuous gas assessment units) is recognized by the USGS for the Bakken TPS in the Williston Basin USA.

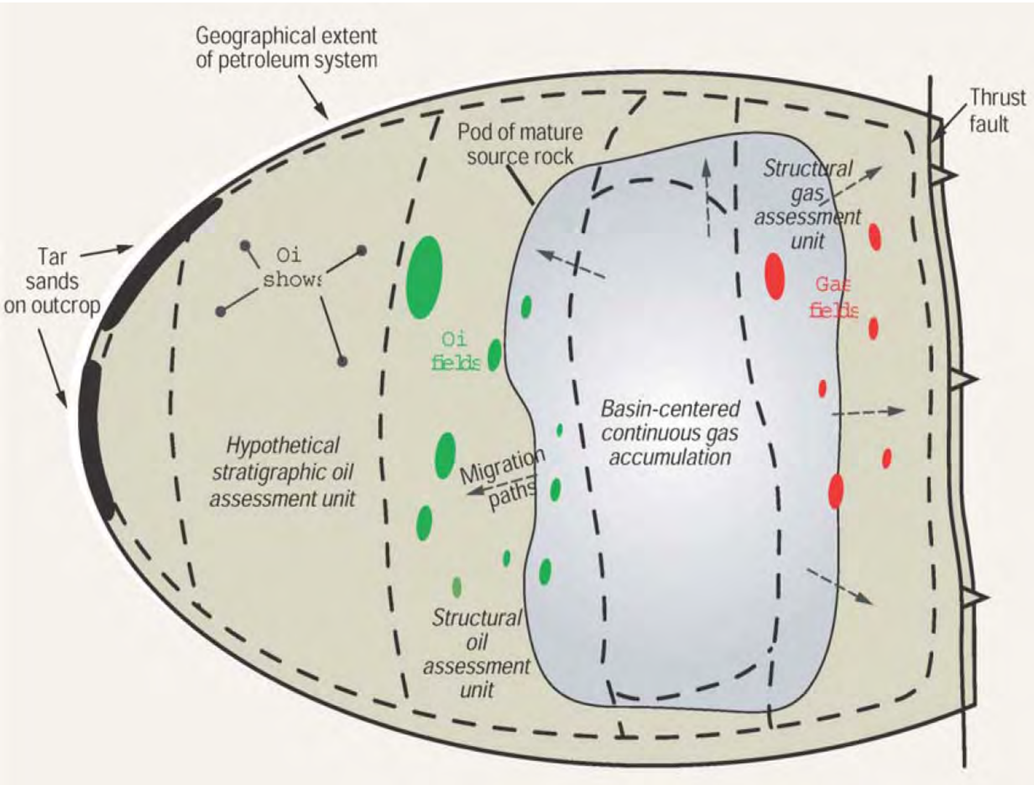


Figure 2 Illustration of the distribution of Assessment Units (AUs) within a Total Petroleum System (TPS)

Often the AU's may also be called plays.

The subdivision of the Lower Larapinta TPS into assessment units(AU's) or plays, was based on:

1. the present formational breakdown which reflects the dominant lithology present in that formation
2. the likely trapping mechanism based on the thermal maturity of the sediments
3. an extensive review of the available well data from mud logs and electric logs.

Note: Only the unconventional resource in the proposed continuous gas and oil AU's are included in this assessment.

The assessment methodology also recognizes the presence of the several different lithologies present in the target unconventional AU's by using different Hydrocarbons-in-Place models and recovery factors for each major Lithotype.

Estimates of the Lithotype thickness within each AU were derived from electric logs and back checked against the mud logs.

Classification of the resource is based on the PRMS guidelines and methodologies proposed by Elliot (SPE 114160).

6 Regional Setting

6.1 Location

The Larapinta Group is part of the Amadeus Basin in central Australia.

The intracratonic Neoproterozoic to Early Carboniferous Amadeus Basin occupies much of the southern quarter of the Northern Territory and extends about 150 km into Western Australia, covering about 170,000 km^2 in total. Central Petroleum operates most of this basin in a mix of granted permits and applications at the 100% net level but for two small prospect blocks which are currently the subject of a conditional 25% farmout to the unlisted junior company, Australian Oil and Gas Limited.

The basin has long established oil and gas production. A gas pipeline links the basin to Darwin, approximately 1,500 km to the North. Oil from the Mereenie Field (operated by Santos in joint venture with Magellan Petroleum Corporation) is shipped by truck from Mereenie to Port Stanvac in South Australia.

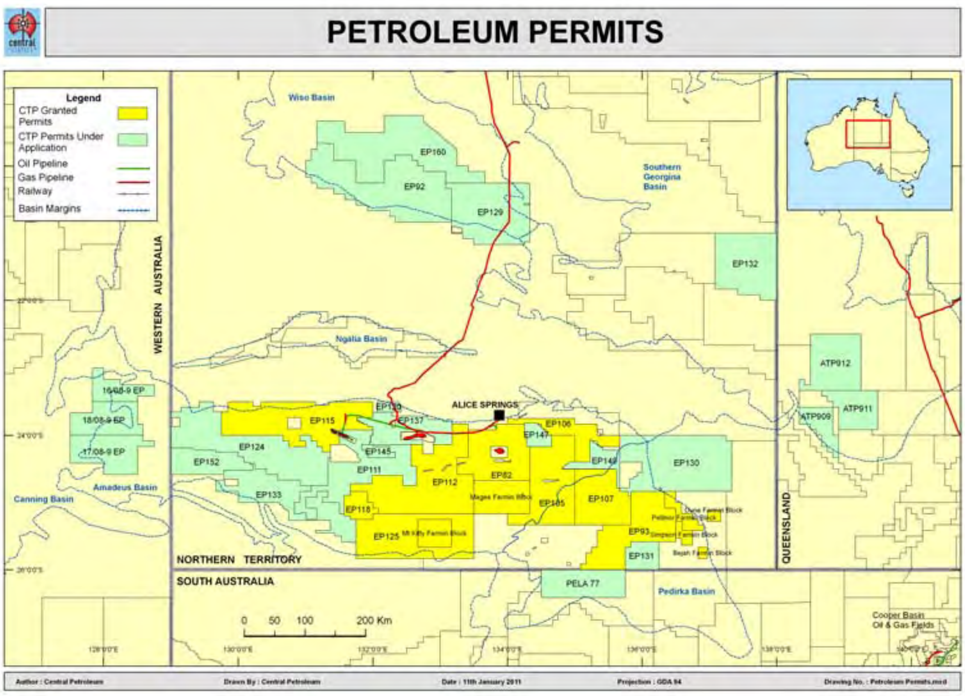


Figure 3 Amadeus Basin Northern Territory Australia

6.2 Regional Geology

The Amadeus Basin, is a multiphase rift - foreland basin with major thrusting occurring in the Late Neoproterozoic and Devonian-Carboniferous. It has a maximum sediment thickness of 14,000 metres with several major depocentres including the Idirriki, Carmichael and Ooraminna Sub-basins and the Missionary Plain Trough along the northern margin and the Mount Currie and Seymour Sub-basins in the south. Early Neoproterozoic volcanics and fluvial siliciclastics in the west form a rift sequence associated with an extensional event caused by the breakup of the Rodinia Supercontinent.

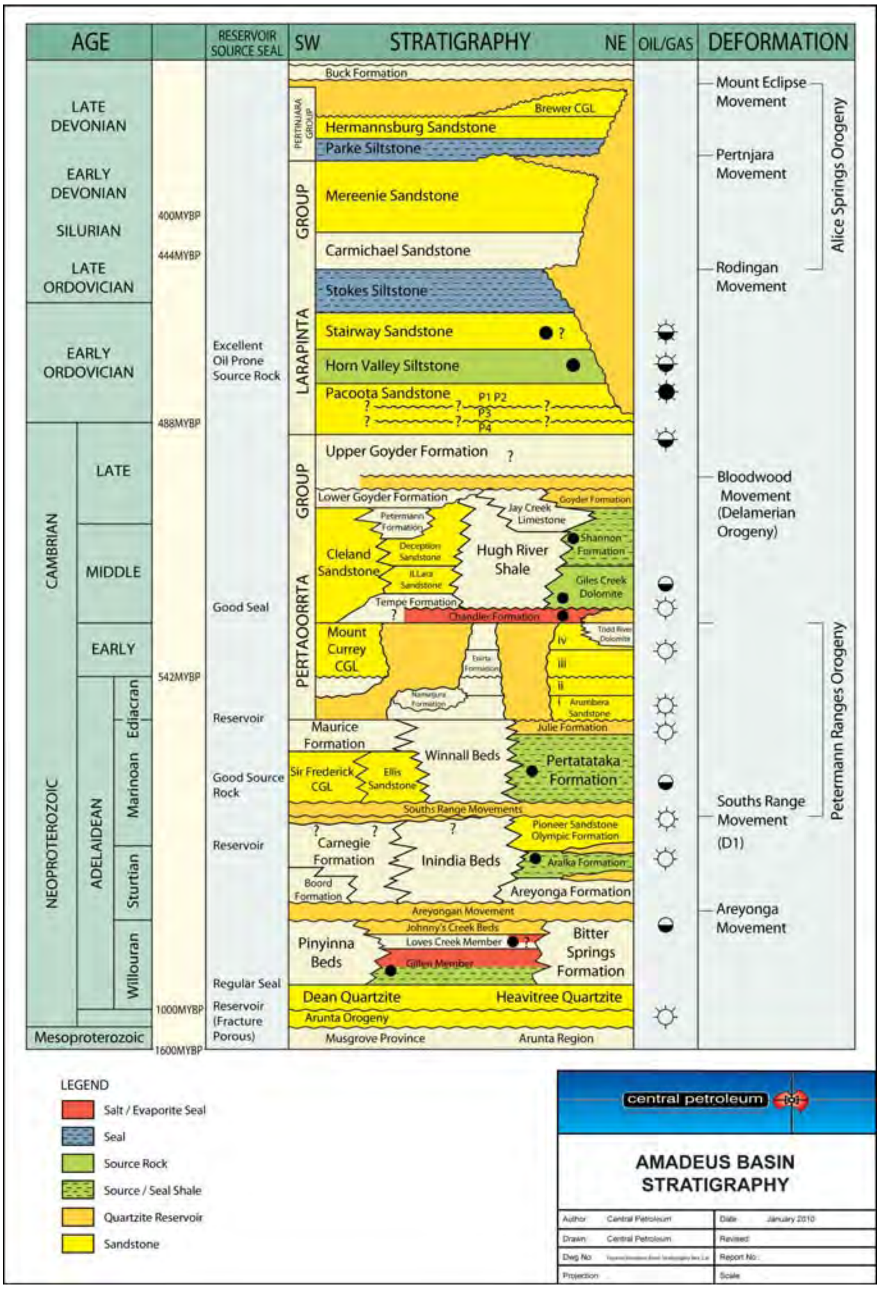


Figure 4 Amadeus Basin Stratigraphy

Subsequent thermal relaxation and subsidence initiated widespread marine siliciclastic and carbonate sedimentation associated with extensive evaporites. Spectacular salt structures are associated with the Neoproterozoic Gillen Salt member of the Bitter Springs Group and the Cambrian Chandler Salt. This marine succession is terminated by an erosional surface which is overlain by fluvial and glacigene sediments associated with the Sturtian and Marinoan glaciations. Subsequent marine siliciclastic and carbonate sedimentation extended into the latest Proterozoic.

Depositional patterns were changed abruptly by the Petermann Ranges Orogeny with extensive uplift along the southwest margin of the basin feeding deposition of widespread fluvial and marine siliciclastics during the latest Proterozoic-Early Cambrian. This was followed by deposition of a succession of marine siliciclastics and carbonates with minor evaporites for most of the remainder of the Cambrian. In the latest Cambrian, the Delamerian Orogeny caused a change to predominantly marine siliciclastic deposition. This continued until the Middle Ordovician when evaporites again appeared.

The final phase of deposition in the basin comprised shallow marine, fluvial and aeolian siliciclastics, which are capped by synorogenic (Alice Springs Orogeny), molasse-type, coarse siliciclastics. The Larapinta Group ranges in age from the Late Cambrian to Late Ordovician.

The Lower Larapinta group of sediments is an informal name used for the purposes of this resource assessment and refers to the Pacoota, Horn Valley and Stairway Formations (Figure 4).

The AGSO paleogeographic model of Australia during the Lower Larapinta time (Figure5) shows marine conditions extending across Central Australia.

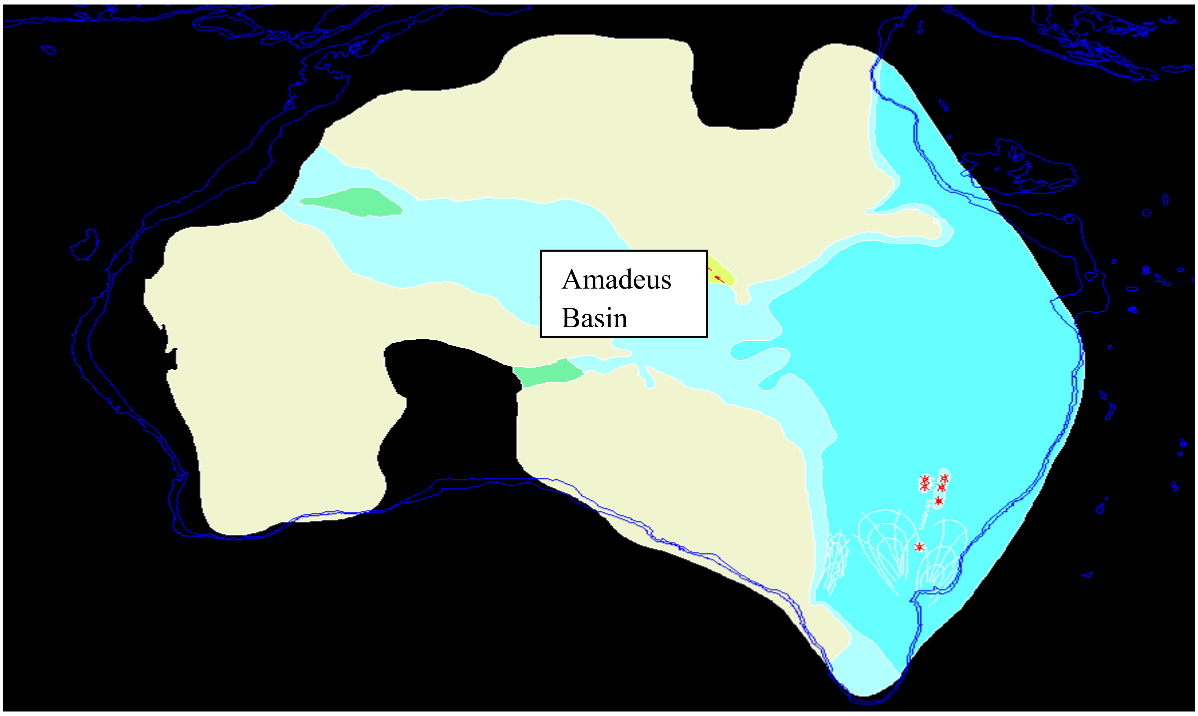


Figure 5 AGSO Ordovician 3 Paleogeographic Map

The Horn Valley Siltstone was deposited in this setting and represents the maximum transgression of this marine phase. Based on this map the lower Larapinta Group was more widespread than is present today due to erosion during the Rodingan Structural event which formed an unconformity in the Larapinta Group at the base of the Carmichael Sandstone.

Hydrocarbons are currently produced from an Early Ordovician source at the Mereenie Oilfield and the Palm Valley Gasfield. The Neoproterozoic sourced Dingo Gasfield is currently undeveloped. Many anticlinal closures in the basin have been tested, but other possible plays such as fault controlled structures and stratigraphic traps have not been drilled. The only commercial petroleum system is the Ordovician Lower Larapinta Group. In this Petroleum System the Horn Valley Siltstone source rock and intra formational source rocks have charged the Conventional Reservoirs of the Ordovician Pacoota and Stairway Sandstone units. These sandstone reservoirs produce oil and gas from both conventional matrix porosity and fractured reservoirs in the Mereenie oil/gas and Palm Valley and gas fields respectively.

Hydrocarbon Occurrences

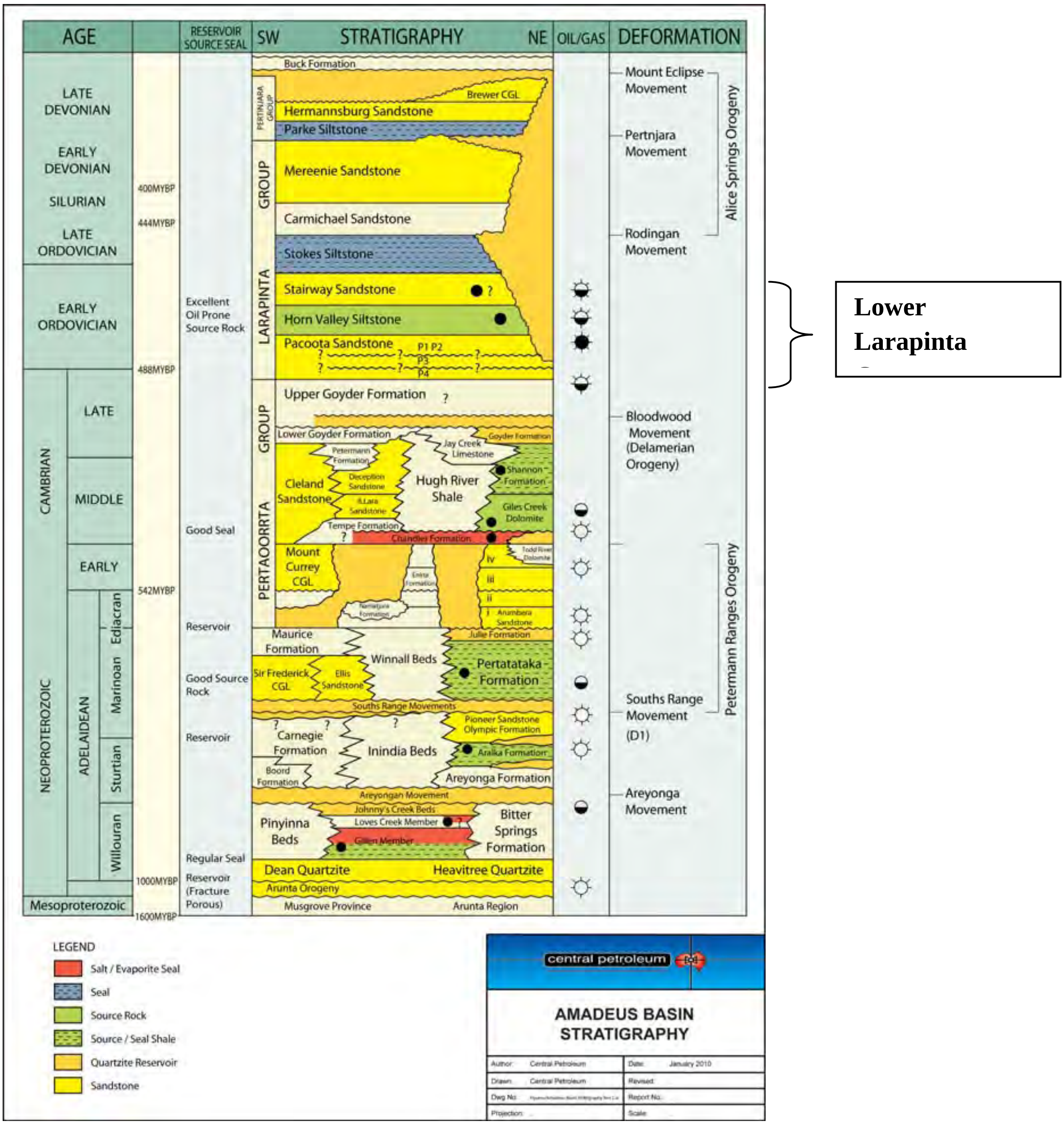


Figure 6 Hydrocarbon Occurrences and Lithologies in the Amadeus Basin

Although there are several potential source horizons and numerous hydrocarbon shows spread throughout the stratigraphic column of the Amadeus Basin, the only commercial quantities of hydrocarbons yet discovered occurs in the Lower Larapinta. The cluster of hydrocarbon occurrences in the Stairway thru Pacoota Formations of the Lower Larapinta group describes the Lower Larapinta Total Petroleum System (TPS)(Figure 5). The organic rich sediments of the Horn Valley Siltstone has probably produced the majority of hydrocarbons but considerable quantities of thinly bedded source rocks are also present in the adjacent Stairway and Pacoota Formations. Thus the sandstones and carbonates of the Stairway and Pacoota Formations have received hydrocarbon charge from both the Horn Valley source pod and interbedded source rocks. The extent of lateral migration away from the mature source pod cannot be determined from the data available.

Thermal Maturity

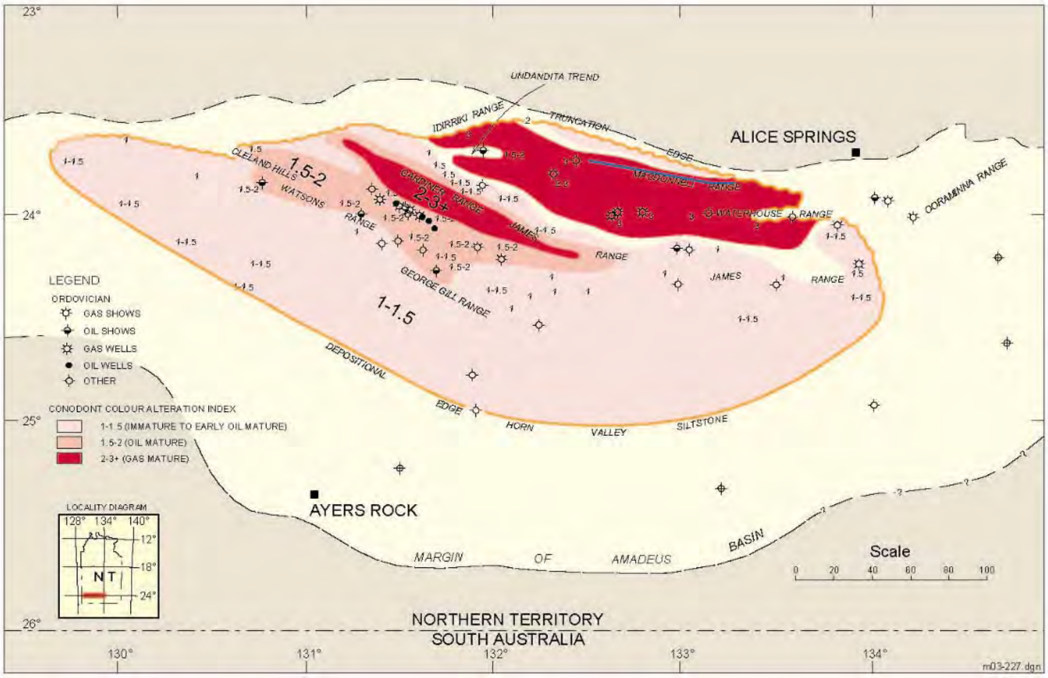


Figure 7 Distribution of Maturity - Horn Valley Siltstone (after Gorter,1984).

The best data available on the thermal maturity of the Lower Larapinta Group is work done by Gorter (1984) on the Horn Valley Siltstone. Note this is based on a conodont colouration index and comparison with the available structure map indicates that the implied maturity depth relationship is inconsistent across the Groups distribution.

In this assessment the depth maturity relationship implied by the Horn Valley maturity map for the central basin area is deemed appropriate for use in determining the distribution of continuous gas and oil assessment units regionally. Some recent maturity data from Johnstone West 1 exploration well in the far west of the province confirms the interpretation provided by using the regional time structure map provided.

7 Lower Larapinta TPS.

Based on the distribution of hydrocarbons and the presence of a mature source pod in the Lower Larapinta Group of the Amadeus Basin (Figure 8 and Attachment 1), the presence of a Lower Larapinta Total Petroleum System (TPS) is clear.

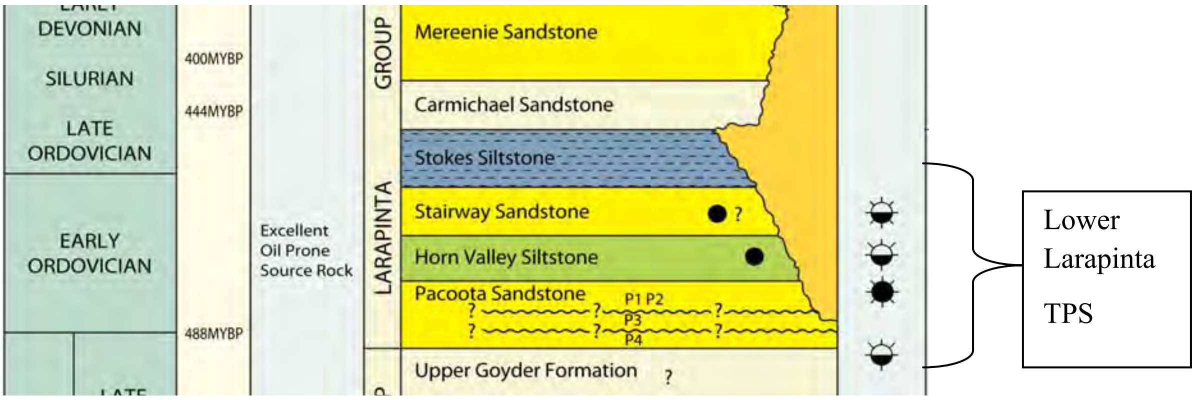


Figure 8 Hydrocarbon Occurrences and Source Rocks in the Lower Larapinta Group, Amadeus Basin

7.1 Type Section

An examination of the type section (Figure 9) of the Lower Larapinta TPS shows that each formation in the Lower Larapinta TPS contains numerous alternating lithologies which can be relatively easily subdivided into Lithotypes by using a gamma cutoff.

The three Lithotypes present are:

1. Shale Lithotype
2. Tight Sandstone Lithotype
3. Mixed Lithotype

It should also be noted that a crossover of the sonic and gamma ray plots is present in a number of shales throughout the section possibly indicating the presence of high TOC. These shale gas signatures have yet to be validated by core studies thus they are noted but not used further in this analysis.

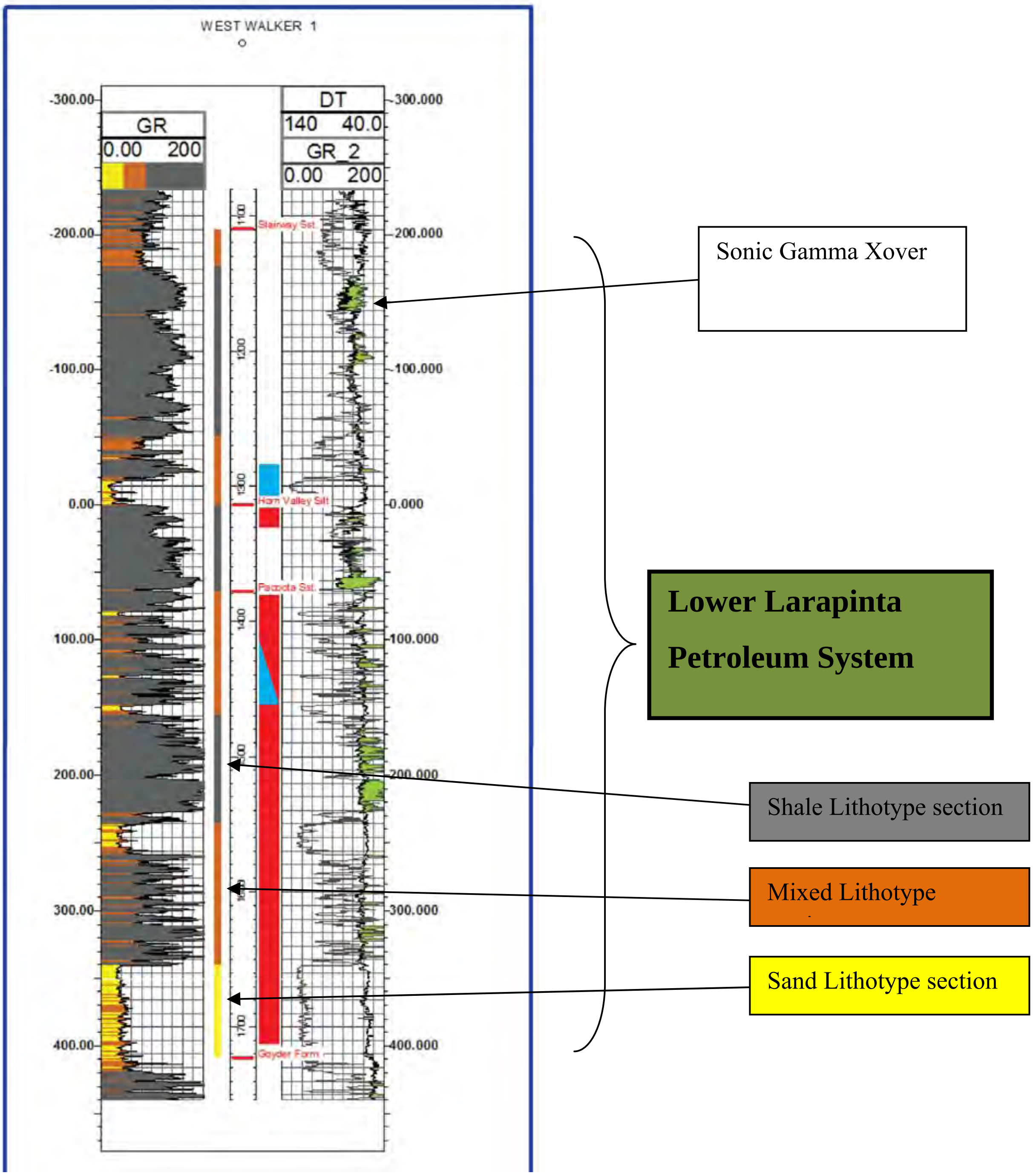


Figure 9 Lower Larapinta Type Section - West Walker 1

7.2 Lithotype Descriptions

The Lower Larapinta TPS consists of several different Lithotypes which can be recognized on the electric logs. The type of hydrocarbon storage, the storage capacity and the optimum completion methods are likely to be different for these Lithotypes thus this assessment treats them separately.

Lithotype 1: Tight Sandstone

Definition

The Tight Sandstone Lithotype has GR<50 API. By definition, Tight Sandstones have permeability less than 0.1mD.

The Tight Sandstone Lithotype is highly silicious and has very little organic content. Occasionally it will have open fracture sets however in this assessment fracture porosity is considered negligible. Locally closed fracture sets may be significant with respect to completion practices such as fracture stimulation.

In tight sandstones hydrocarbons are stored as free gas and or oil in the matrix porosity.

Type Section

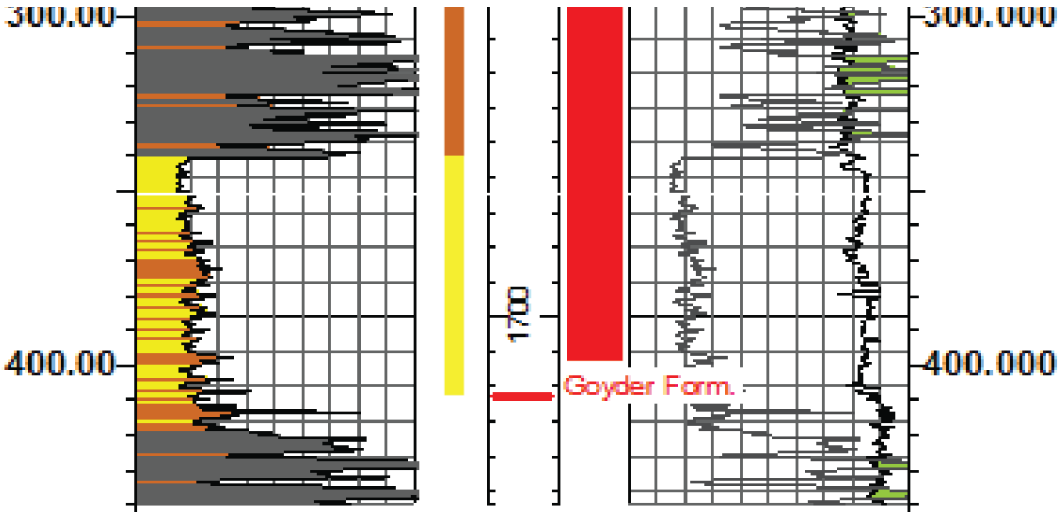


Figure 10 Tight Sandstone Type Section - West Walker 1

An example of a tight sandstone reservoir is the Mesaverde Formation in the Green River Basin where The Jonah and Pinedale Fields contain in excess of 30 TCF Gas recoverable from reservoirs with less than 0.1md at depths from 6-8000 ft. Completions are in vertical wells with multistage fracs.

Lithotype 2: Shale

Definition

Shale is the Lithotype with a Gamma > 100 API.

The Lithotype is not uniform shale but a highly laminated siltstone/shale with calcareous layers and varying degrees of dispersed organic matter. This Lithotype may contain high (>5%) TOC levels. There is no widespread fracture porosity in the shales however locally closed fractures may be significant and important with respect to stimulation practices.

Hydrocarbons in the Shale Lithotype are stored as

- Free gas and oil residing in matrix porosity
- Sorbed gas (bound to organic matter).

Note there is no shale oil production capacity attributed to adsorption.

Type section

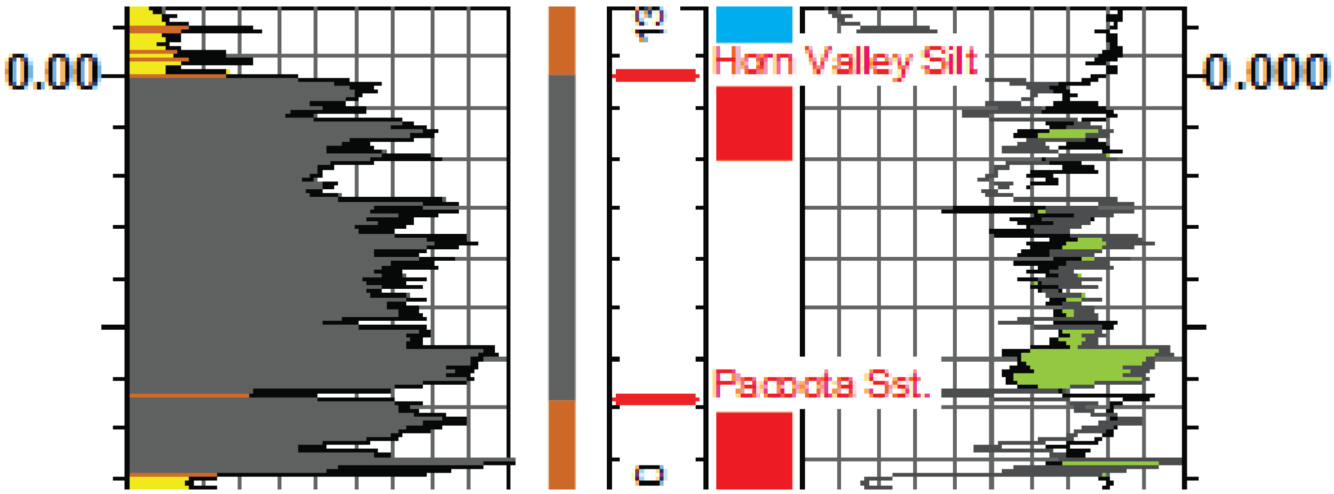


Figure 11 Shale Type Section - West Walker 1

Examples of a Shale Lithotype are the Barnett , Marcellus and Fayettville Shales. Completions are by multilaterals with multistage fracs.

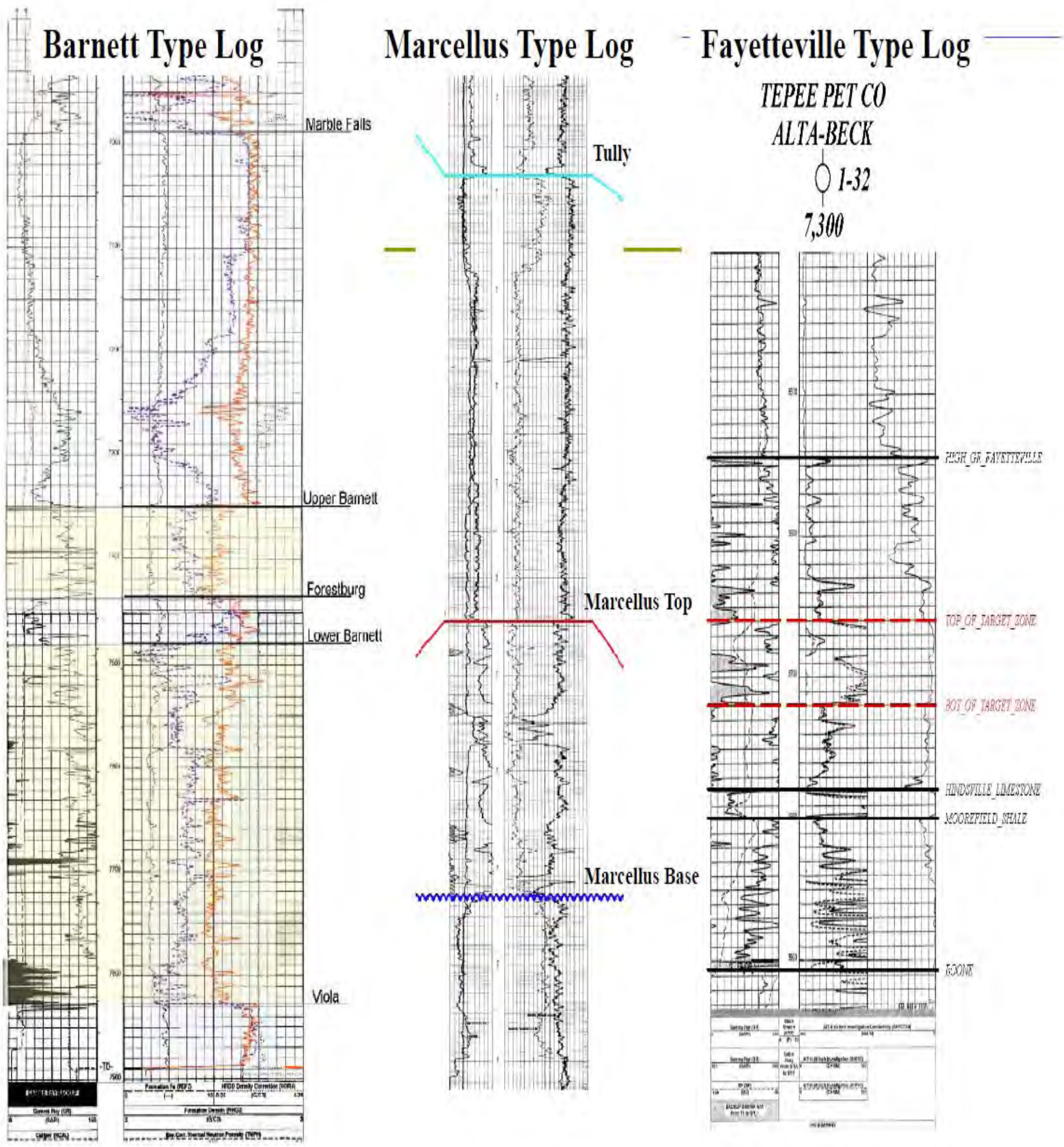


Figure 12 Shale Lithotype - USAnalogs

Lithotype 3: Mixed Lithology

Definition

This Lithotype has Gamma ray between 50 and 90 API and is comprised of finely laminated tight sand, silt and shale stringers. Occasionally they are calcareous.

The lithologies in the Mixed Lithology Lithotype do not necessarily have the same HIP and recovery parameters as the lithologies in the Tight Sandstone or Shale Lithotypes.These differences are a consequence of the depositional environment. For example, the organic matter in the Mixed Lithotype were deposited in a relatively oxygen rich environment whereas in the Shale Lithotype organics can be deposited in anoxic conditions

Hydrocarbons in the Mixed Lithology Lithotype are stored as:

- Free hydrocarbons (residing in matrix porosity)
- Sorbed gas (bound to organic matter).

Note there is no oil production attributed to desorption.

Type section

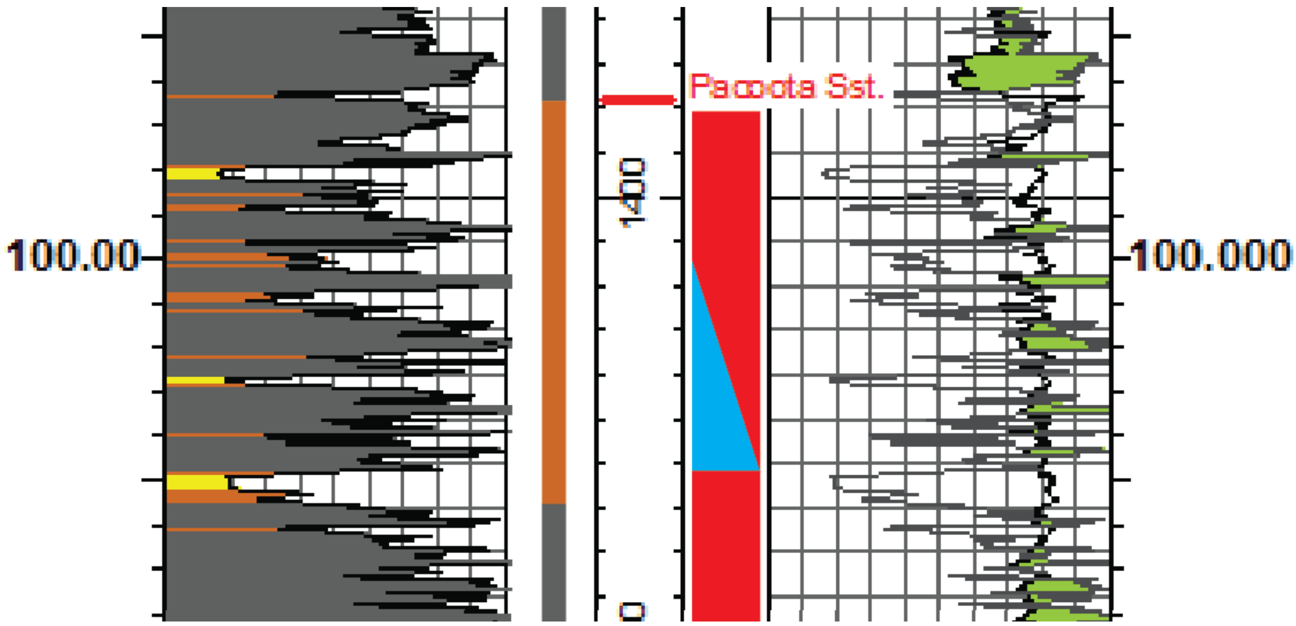


Figure 13 Mixed Lithotype Type Section - West Walker 1

An analog for this Lithotype is the lower Bakken Lithofacies 4

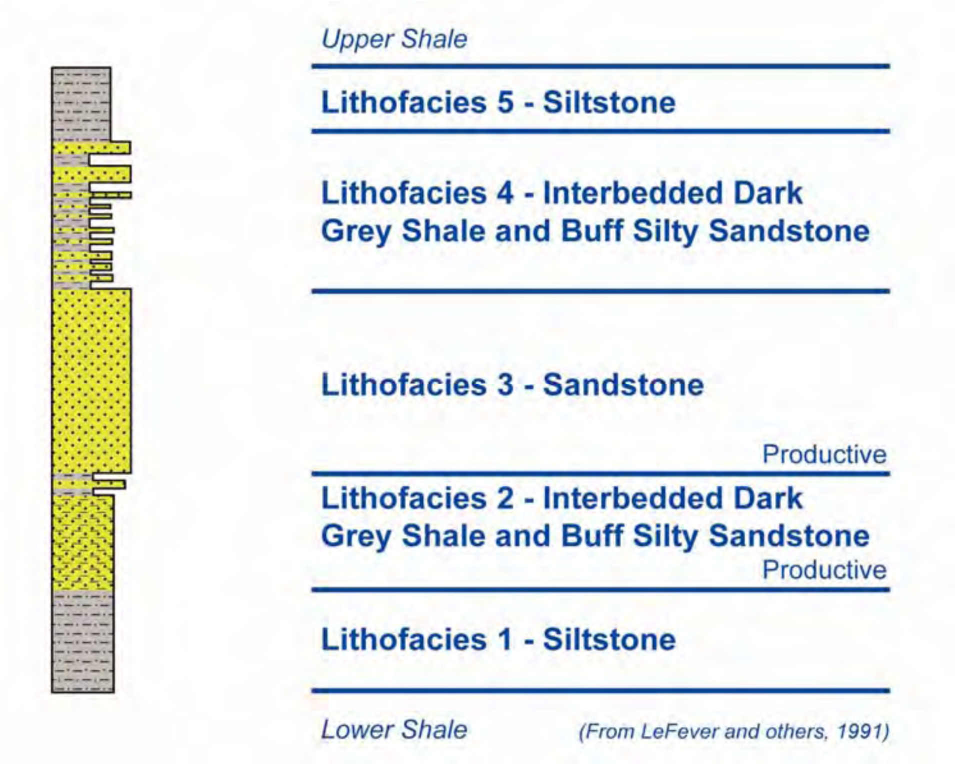


Figure 14 Mixed Lithology Lithofacies Analog - Bakken Shale Play -Williston Basin USA

Unconventional Assessment Units

Within the Lower Larapinta TPS it is possible to delineate a number of likely continuous hydrocarbon assessment units based on a combination of:

1. formational lithological subdivision
2. maturity of those formations
3. the hydrocarbon shows encountered.

A more detailed examination of the subdivision of the Lower Larapinta TPS into assessment units (AU's) is contained in Attachment 1.

The data indicates the Horn Valley Siltstone, the major source pod in the Lower LarapintaTPS, is likely to have a continuous gas Assessment Unit (AU) with an adjacent continuous oil rim. For the remaining formations of the Lower Larapinta TPS, the Stairway and Pacoota Formations, the presence of movable water legs below the discovered hydrocarbon pools indicates that all wells to date have penetrated conventional (non continuous)accumulations. However in the deeper parts of the basin it is possible for continuous gas AUs to exist in these formations just as they do in formations with similar lithologies in the Piceance and Green River Basins of the USA. Although both the Pacoota and the Stairway Formations have intermittent thick (TOC rich?) shaley units it is considered unlikely that regionally significant continuous oil accumulations exist in these sandstone dominated source poor formations.

For the Lower Larapinta TPS in the Amadeus Basin the following unconventional assessment units(AUs) are proposed:

1. Horn Valley continuous oil AU
2. Horn Valley continuous gas AU
3. Stairway continuous gas AU
4. Pacoota continuous gas AU

The vertical and areal distribution of these AU's or plays is shown in the following diagrammes (15 thru 18)and it is based on these maps that the areas of the AU's or plays are determined.

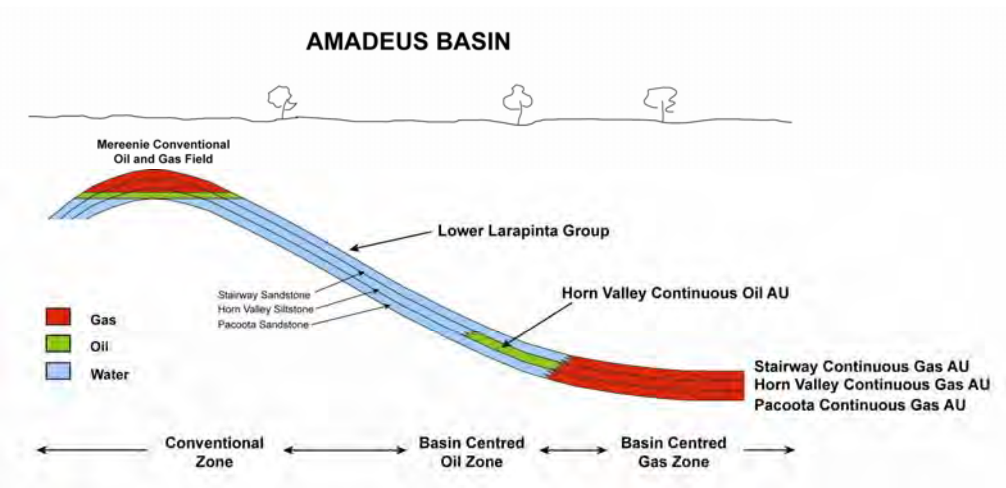


Figure 15 Diagramatic Cross Section showing Unconventional Assessment Units (AUs) of the Lower Larapinta TPS

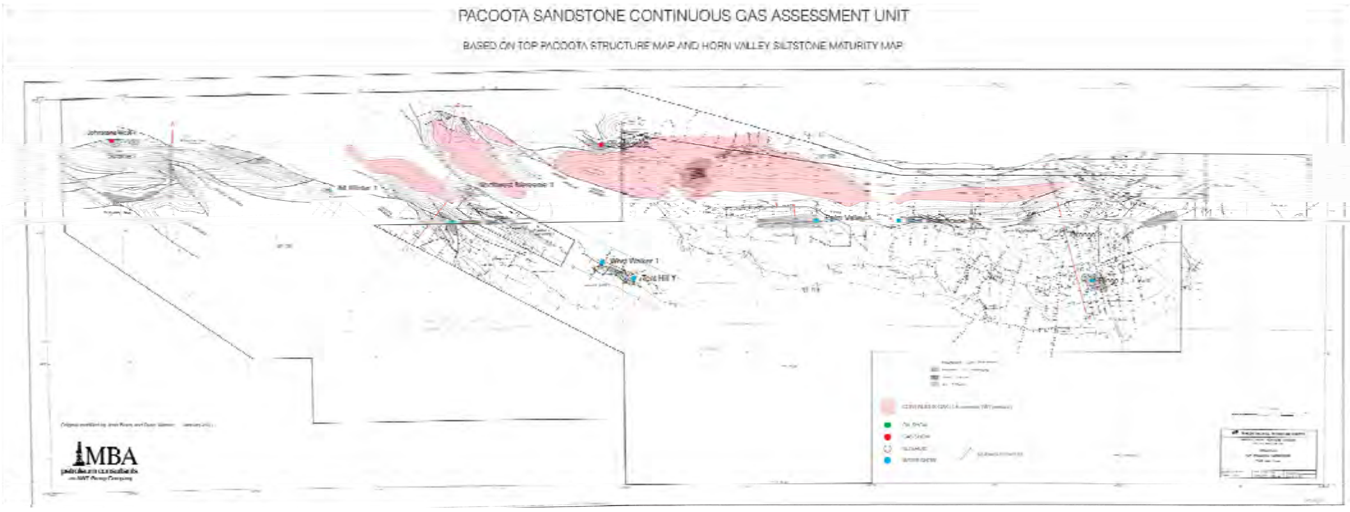


Figure 16 Distribution Pacoota Continuous Gas AU.

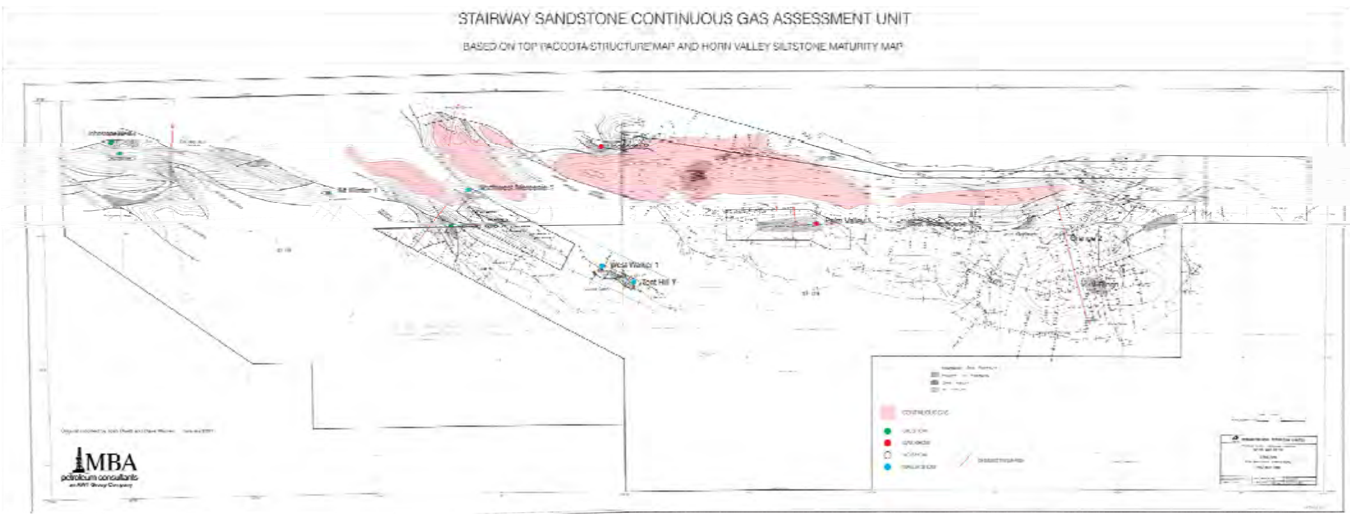


Figure 17 Distribution Stairway Continuous Gas AU

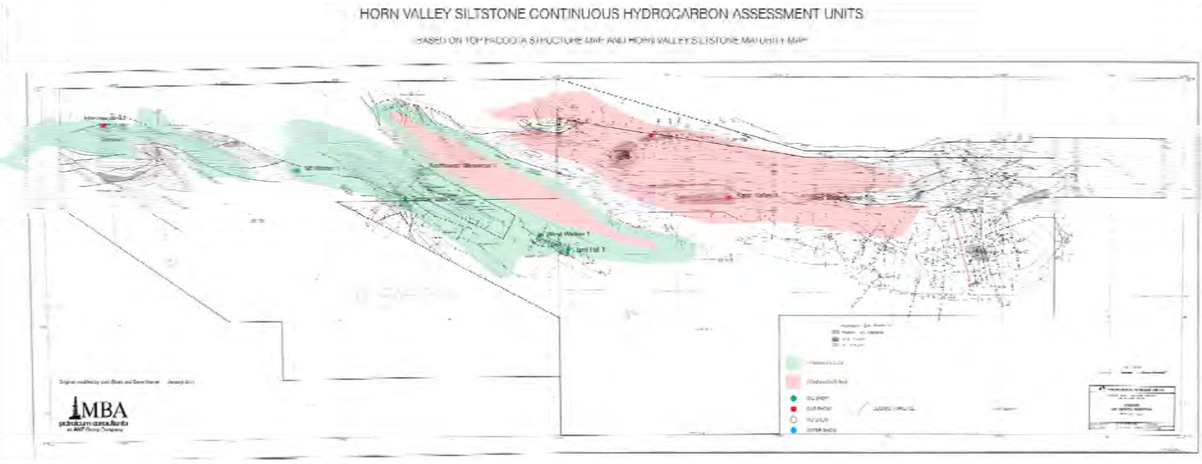


Figure 18 Distribution Horn Valley Continuous Oil and Continuous Gas AU's

8 Hydrocarbons - In-Place Estimate

8.1 Methodology

The methodology to calculate the Unconventional Hydrocarbons in Place for the Lower Larapinta Group TPS assessment units (AU's) is probabilistic and has by necessity, as each Lithotype has a unique combination of hydrocarbon storage and production mechanisms , been based on Lithotype specific HIP models.

These HIP models are:

1. Tight Sandstones
1. Shales
2. Thinly interbedded sandstone, siltstone and shales or Mixed Lithology.

The HIP models are as follows:

Tight Sandstone Lithotype

Gas-In-Place Model
The storage mechanism in the tight sandstones is as free gas in the matrix porosity. Where open fractures occur these will also store gas, however it is most likely to be insignificant.

$$OGIP = 43560 * A * h * r * \Phi * (1-Sw) * FVF$$

Oil-In-Place Model
The storage mechanism in the tight sandstones is as free oil in the matrix porosity. Where open fractures occur these will also store oil, however this volume is considered to be insignificant.

$$OOIP = 7758 * A * h * r * \Phi_m * (1- S_{wm}) * FVF$$

Shale Lithotype

Gas-In-Place Model
The shale has a combination of adsorption, related to the clays and organic content, as well as free gas in the matrix porosity. Where open fractures occur these will also store gas, however the play volume is likely to be insignificant

$$OGIP = A * h * r * [\{ 43560 * FVF * ((\Phi_f * (1-S_{wf}) + (\Phi_m * (1- S_{wm}))\} + 1359.7 * G_s * \rho]$$

Oil-In-Place Model
In shales oil can be stored by adsorption, related to the clays and organic content, as well as free oil in the matrix porosity. However, in shales only the free oil content is considered producible by the USGS in their assessments of oil shales. In the Lower Larapinta shales the matrix porosity is considered too low to be significant as are open fracture systems.

OOIP = 0-no production

Mixed Lithology

Gas-In-Place Model

The Mixed Lithology Lithotype is a mixture of thinly bedded shales and sandstones thus the Lithotype has a combination of both adsorption and matrix storage. Where open fractures occur these will also store gas, however it is most likely to be regionally insignificant.

The estimate for the mixed Lithotype uses the same equations as for the Lithotypes above.

OGIP = Shale Fraction OGIP + Sandstone Fraction OGIP

Shale Fraction

$$OGIP = A * h*r* [\{ 43560 * FVF * ((\Phi_f * (1-S_{wf}) + (\Phi_m * (1- S_{wm}))\} + 1359.7 * G_s * \rho]$$

and

Sand Fraction

$$OGIP = 43560 * A * h *r* \Phi_m *(1- S_{wm})* FVF$$

Oil-In-Place Model

This Lithotype is a mixture of thinly bedded shales, siltstone and sandstones thus it will have a combination of both adsorption and matrix storage. As with the other shale Lithotypes the adsorbed oil and matrix content is not considered recoverable or significant and therefore is ignored. Where open fractures occur these will also store oil, however the total volume is considered insignificant.

OOIP = Shale Fraction OOIP + Sandstone Fraction OOIP

Shale Fraction OOIP = 0 -no production

and

Sand Fraction $OOIP = 7758 * A * h *r* \Phi_m *(1- S_{wm})* FVF$

Symbols used

OGIP	is	Original Gas In Place	in	Scf
OOIP	is	Original Oil In Place	in	BBLS
A	is	Area in		Acres
h	is	Pay Thickness in		Ft
r	is	Net to Gross ratio	in	Decimal Fraction
Φ_m	is	Effective matrix porosity	in	Decimal Fraction
FVF	is	Formation Volume Factor	in	Units
S_{wm}	is	Matrix water saturation in		Decimal Fraction

G_s	is	Adsorbed Gas Storage Capacity	in	Scf/Ton
ρ	is	Shale density	in	G/cm^3

8.2 HIP Inputs - Horn Valley Continuous Gas AU

Lithotype	Parameter		P90 Low	P50 Most Likely	P10 High	Distribution
Common	Area	A	50,000	800,000	1,830,000	Log Normal
Common	Fm Vol Factor	FVF	100	160	300	Log Normal
Common	Net to Gross Ratio	r	0.1		0.3	Normal
Sandstone	Thickness	h	10	15	50	Log Normal
	Porosity	Φ	0.04		0.08	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log normal
Shale	Thickness	h	15	100	250	Log Normal
	Matrix Porosity	$Φ_m$	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.15	0.3	0.6	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	150	300	Log Normal
	Density	ρ	2.5		2.7	Normal
ML Sandstone	Thickness	h	7.5	50	125	Log Normal
	Porosity	Φ	0.04		0.06	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log Normal
ML Shale	Thickness	h	7.5	50	125	Log Normal
	Matrix Porosity	$Φ_m$	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.15	0.3	0.60	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	100	300	Log Normal
	Density	ρ	2.5		2.7	Normal

Analog: Barnett Shale

Dom Lithotype	Area (Acres)	Thicknes (FT)	$Φ_m$ %	S_{wm} %	G_s (scf/ton)	ρ (grm/cc)

Shale	3.2 mill	300	1-6	10-80	30 -140	?

8.3 HIP Inputs - Horn Valley Continuous Oil AU

Lithotype	**Parameter**		**P90** **Low**	**P50** **Most Likely**	**P10** **High**	**Distribution**
Common	Area	A	50,000	650,000	1,740,000	Log Normal
Common	Fm Vol Factor	FVF	1	1	1	Uniform
Common	Net to Gross Ratio	r	0.1		0.3	Normal
Sandstone	Thickness	h	10	15	50	Log Normal
	Porosity	Φ	0.04		0.08	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log normal
Shale	Thickness	h				Log Normal
	Matrix Porosity	Φ_m				Normal
	Matrix Water Sat	S_{wm}				Log Normal
ML Sandstone	Thickness	h	7.5	50	125	Log Normal
	Porosity	Φ	0.03		0.06	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log Normal
ML Shale	Thickness	h				Log Normal
	Matrix Porosity	Φ_m				Normal
	Matrix Water Sat	S_{wm}				Log Normal

Analog: Bakken Shale

Note completions are in the Middle Bakken Sandstone - Not in surrounding shales

Dom Lithotype	Area (Acres)	Thickness (FT)	Φ_m %	S_{wm} %		
Tight Sandstone	?	30	5-8.5	?		

8.4 HIP Inputs - Pacoota Continuous Gas AU

Lithotype	Parameter		P90 Low	P50 Most Likely	P10 High	Distribution
Common	Area	A	50,000	300,000	850,000	Log Normal
Common	Fm Vol Factor	FVF	100	160	300	Log Normal
Common	Gross to net ratio	r	0.1		0.3	Normal
Sandstone	Thickness	h	15	150	300	Log Normal
	Porosity	Φ	0.04		0.08	Normal
	Water Saturation	Sw	0.1	0.3	0.7	Log normal
Shale	Thickness	h	15	100	450	Log Normal
	Matrix Porosity	Φ_m	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.15	0.3	0.5	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	150	300	Log Normal
	Density	ρ	2.5		2.7	Normal
ML Sandstone	Thickness	h	30	125	300	Log Normal
	Porosity	Φ	0.04		0.06	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log Normal
ML Shale	Thickness	h	30	125	300	Log Normal
	Matrix Porosity	Φ_m	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.1	0.3	0.50	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	100	300	Log Normal
	Density	ρ	2.5		2.7	Normal

Analog: Lance/Mesaverde Formation - Jonah Field - Green River Basin USA

Dom Lithotype	Area (KAcres)	Thicknes (FT)	Φ_m %	S_{wm} %		
Tight Sandstone	23	600	5 - 14	30-60		

8.5 HIP Inputs - Stairway Continuous Gas AU

Lithotype	**Parameter**		**P90** **Low**	**P50** **Most Likely**	**P10** **High**	**Distribution**
Common	Area	A	50,000	300,000	850,000	Log Normal
Common	Fm Vol Factor	FVF	100	160	300	Log Normal
Common	Gross to Net Ratio	r	0.1		0.3	Normal
Sandstone	Thickness	h	15	150	600	Log Normal
	Porosity	Φ	0.04		0.08	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log normal
Shale	Thickness	h	15	100	450	Log Normal
	Matrix Porosity	Φ_m	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.15	0.3	0.5	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	150	300	Log Normal
	Density	ρ	2.5		2.7	Normal
ML Sandstone	Thickness	h	7.5	75	500	Log Normal
	Porosity	Φ	0.04		0.06	Normal
	Water Saturation	Sw	0.1	0.2	0.5	Log Normal
ML Shale	Thickness	h	7.5	125	500	Log Normal
	Matrix Porosity	Φ_m	0.015		0.04	Normal
	Matrix Water Sat	S_{wm}	0.15	0.3	0.60	Log Normal
	Adsorbed Gas Storage Capacity	G_s	50	150	300	Log Normal
	Density	ρ	2.5		2.7	Normal

Analog: Lance/Mesaverde Formation - Jonah Field - Green River Basin USA.

Dom Lithotype	Area (KAcres)	Thicknes (FT)	Φ_m %	S_{wm} %		
Tight Sandstone	23	600	5 - 14	30-60		

8.6 HIP Results

Au	HIP (TCF or Billion BBLS)			
	P90	P50	P10	Mean
Horn Valley Continuous Gas AU	7.8	20.9	56.7	27.9
Pacoota Continuous Gas AU	6.7	18.2	48.0	24.4
Stairway Continuous Gas AU	3.0	8.9	25.6	12.8
Total Gas				65.10 TCF
Horn Valley Continuous Oil AU	1.3	3.4	8.1	4.2
				4.2 Billion BBLS

9 Hydrocarbon Accumulation Classification

9.1 Methodology

The methodology used to classify the resources for this assessment follows the methods established by the PRMS and Elliot (2008, SPE114160). Figure 19 is a schematic diagram of the PRMS classification scheme.

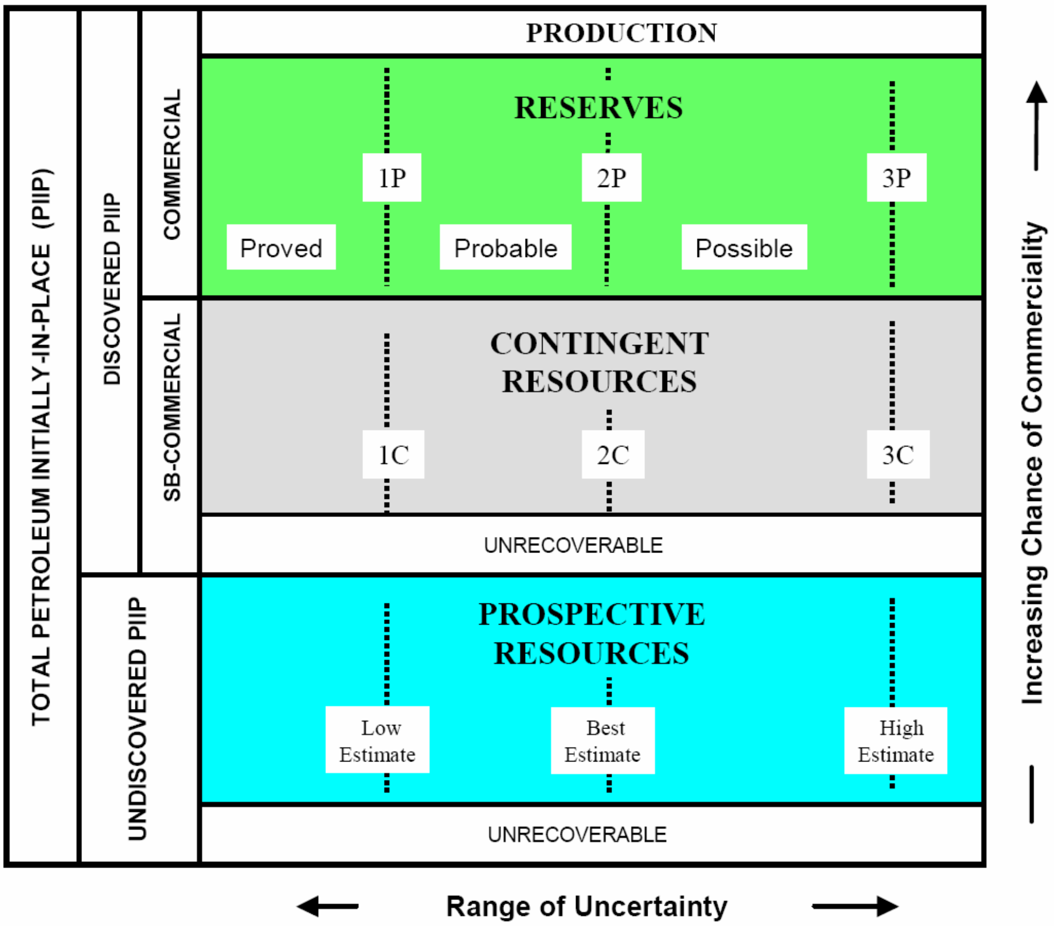


Figure 19 PRMS Classification

The difference between prospective and contingent resources is the discovery of those resources.

Under the PRMS, Discovered Petroleum Initially-in-Place is defined as "that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production."

PRMS defines "known accumulation" as:

"to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons."

With the PRMS rules in mind Elliot has created a system of six decision rules to ascertain discovery status. The process of determining the discovery status is outlined on the following flow chart:

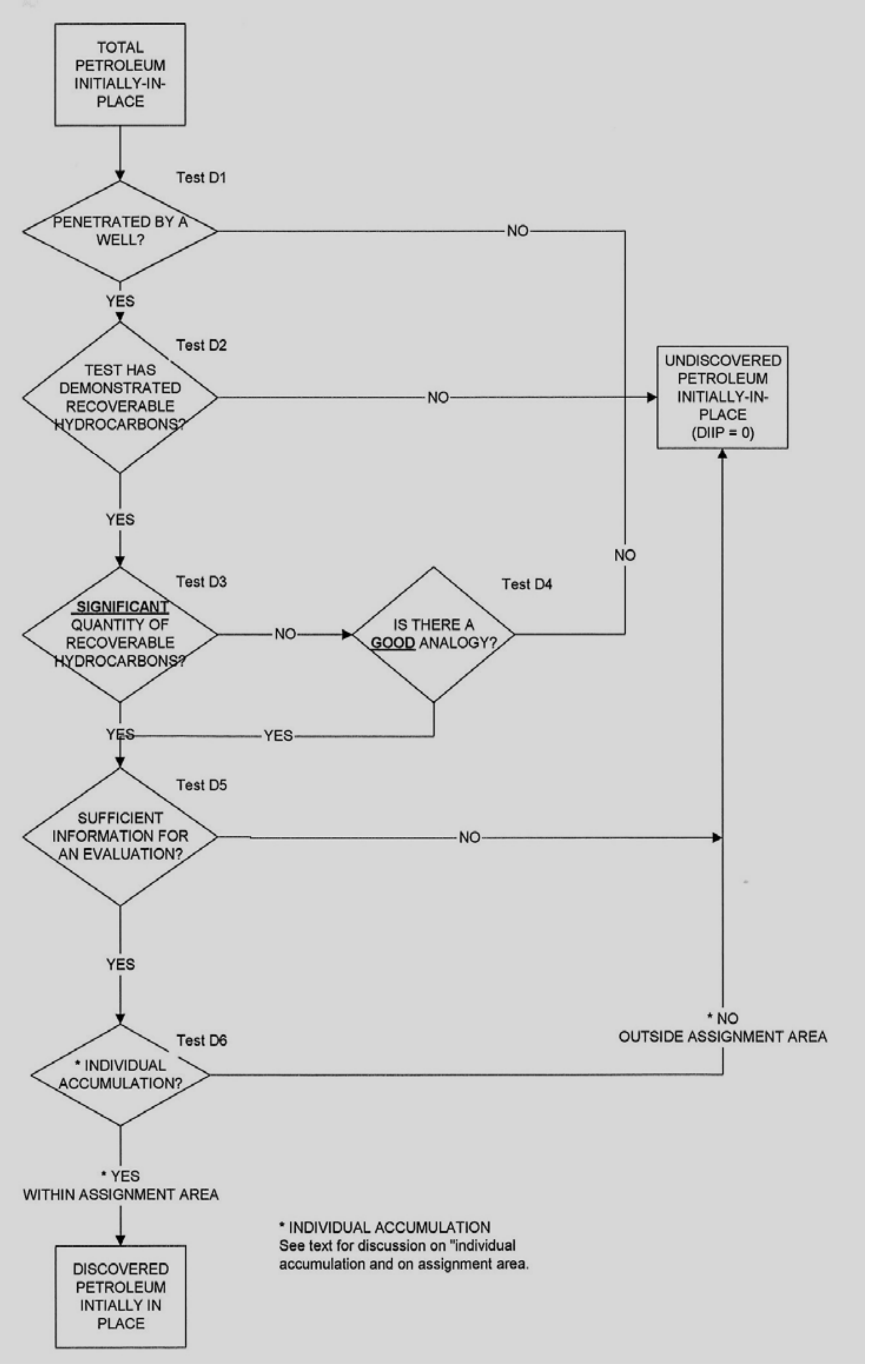


Figure 20 Flow Chart for Discovery Status. Elliot SPE 114160.

9.2 Results

Based on the data available and the utilization of this flow chart none of the assessment units or plays can be described as discovered. Thus all the AU's HIP are classified as Prospective Resources.

Assessment Unit	Mean HIP	Classification
Horn Valley Continuous Oil	4,508 MMBBLS	Prospective Resource
Horn Valley Continuous Gas	27,851 BCF	Prospective Resource
Stairway Continuous Gas	12,753 BCF	Prospective Resource
Pacoota Continuous Gas	24,377 BCF	Prospective Resource

10 Technically Recoverable Resources

10.1 Lower Larapinta TPS Assessment Units - Analogs from North America

Given the lack of production data available on the proposed assessment units within the Lower Larapinta TPS it is useful to benchmark recovery factors used for these plays against producing analogs in North America.

The basis for establishing the analogs is the dominant Lithotypes present in each AU and their architecture or spatial frequency. The Lithotype analogs have been discussed previously in the Lithotype description (Section 7.2).

The analogs for the AU's present in the Lower Larapinta TPS are:

AU	North American Analog	Completion
Horn Valley Cont Gas	Barnett	Horiz with Multistage frac
Horn Valley Continuous Oil	Bakken	Horiz with Multistage frac
Pacoota Continuous Gas	Jonah Field-Mesaverde	Vertical Multistage Frac
Stairway Continuous Gas	Johah Field - Mesaverde	Vertical Multistage Frac

10.2 Recovery Factors

As there is no production in Australia from unconventional reservoirs as yet, the recovery factors applied to the Assessment Unit HIP's are based on the published recovery factors for the North American analogs. These are based on current well performance and the current well spacing. Recent developments have increased the well density in all these plays and mostly incremental reserves have resulted. For example in Jonah the published recovery factor is between 20 and 40%, however new development spacing down to 5 acres indicates recoveries in the vicinity of 80% may be achieved. Thus the published range is used to represent the P90 to P50 spread in a normal distribution model.

AU	Analog	Completion	Published RF	Spread Applied	
				P90	P50
Horn Valley Continuous Gas	Barnett	Horiz with Multistage frac	20-40%	15	40
Horn Valley Continuous Oil	Bakken	Horiz with Multistage frac	5-15%	5	15
Pacoota Continuous Gas	Jonah - Mesaverde	Vertical Multistage Frac	20-40%	20	40
Stairway Continuous Gas	Jonah Mesaverde	Vertical Multistage Frac	20-40%	20	40

10.3 Results

Assessment Unit	Prospect Recoverable Resource (TCF or Billion BBLS)			
	P90	P50	P10	Mean
Stairway Sandstone Continuous Gas AU	1.1	3.4	10.5	5.1
Pacoota Sandstone Continuous Gas AU	2.4	7.0	19.7	9.8
Horn Valley Continuous Gas AU	2.6	7.7	23.8	11.3
TOTAL GAS				25.9 TCF
Horn Valley Continuous Oil AU	0.207	0.77	2.5	1.14
Total Oil				1.1 Billion BBLS

Lower Larapinta Group regional cross-section A - A'

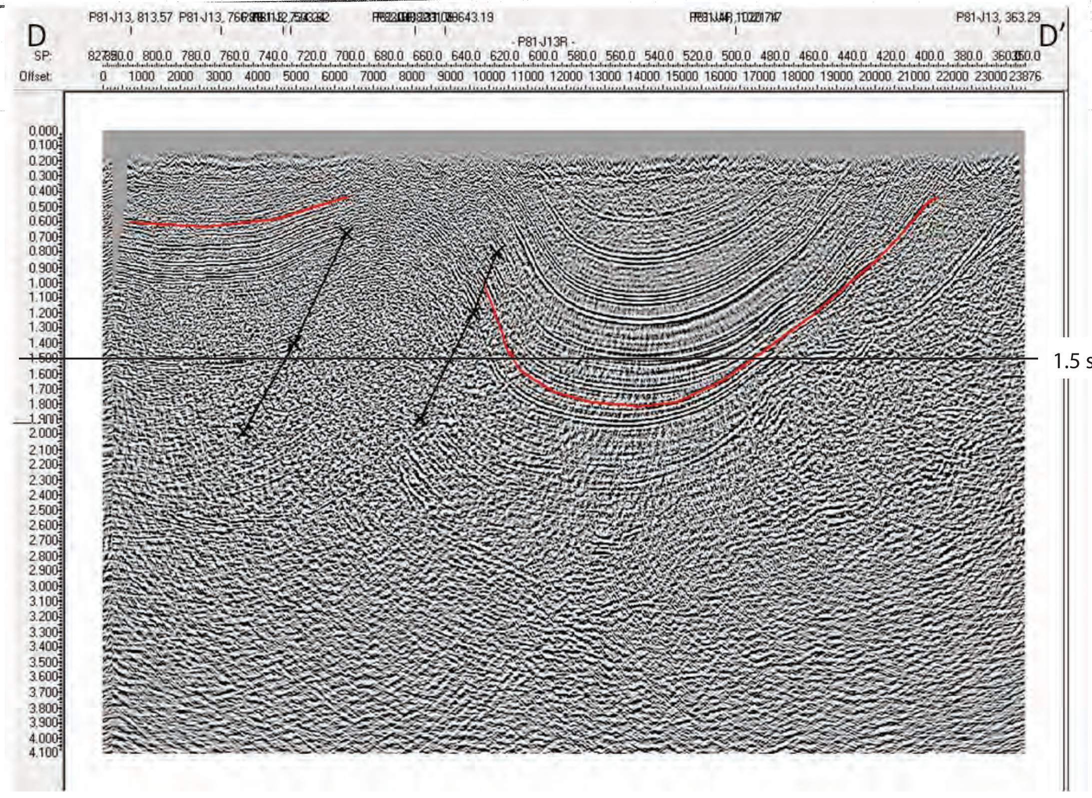
Johnstone West 1 - Dingo 1

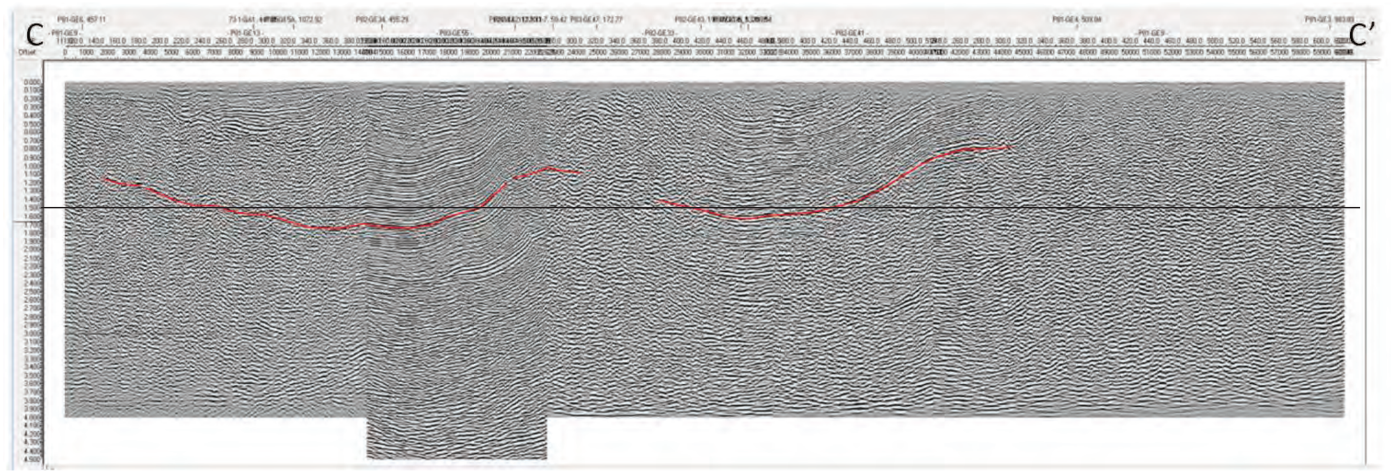
MBA
petroleum consultants
an AWT Group Company

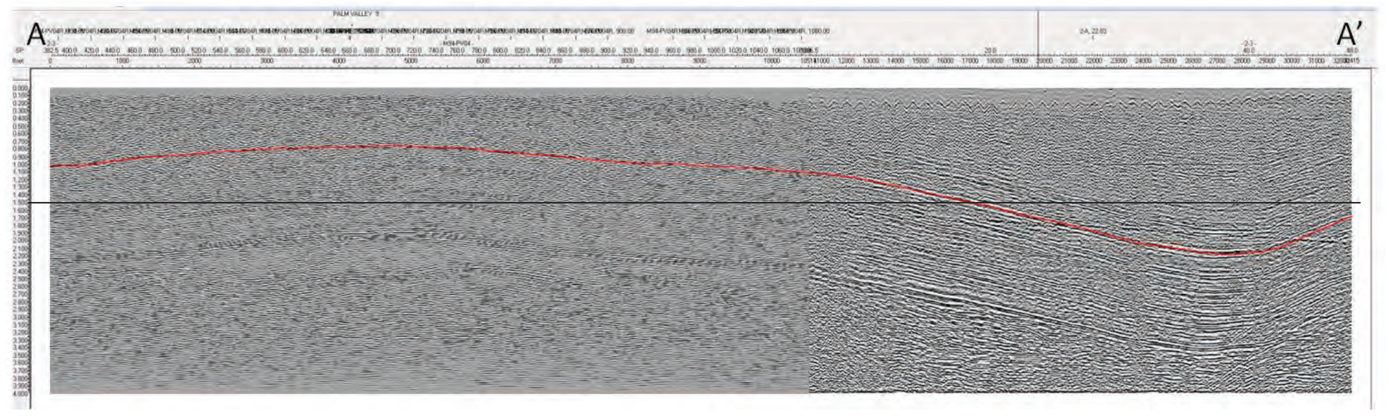
cross-section created by Josh Bluett and Dave Warner January 2011

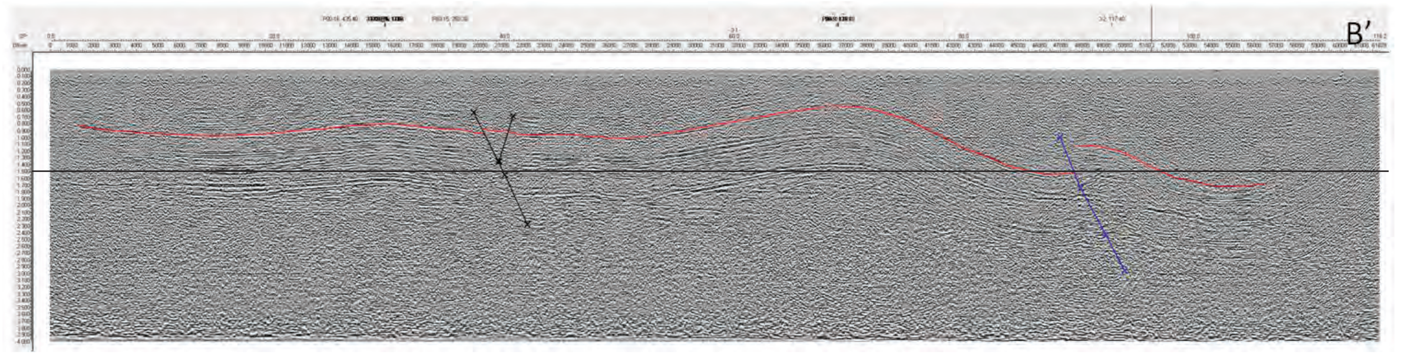
STAIRWAY SANDSTONE CONTINUOUS GAS ASSESSMENT UNIT

BASED ON TOP PACOOTA STRUCTURE MAP AND HORN VALLEY SILTSTONE MATURITY MAP



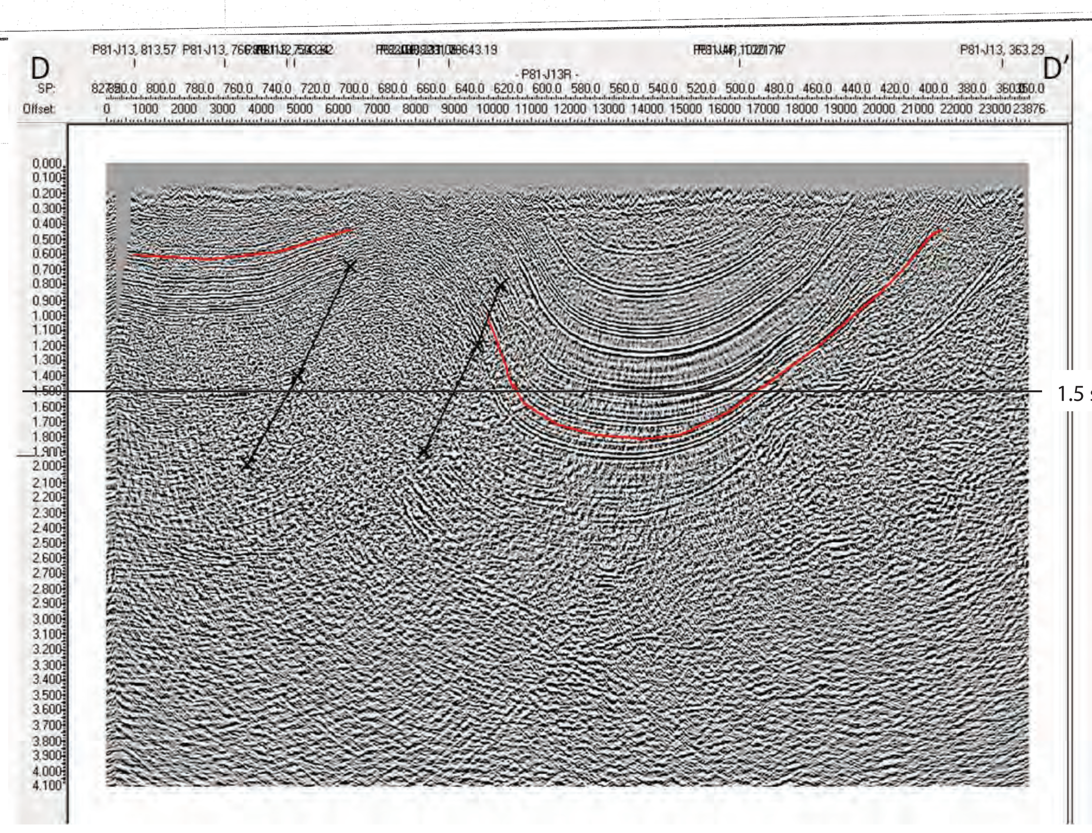


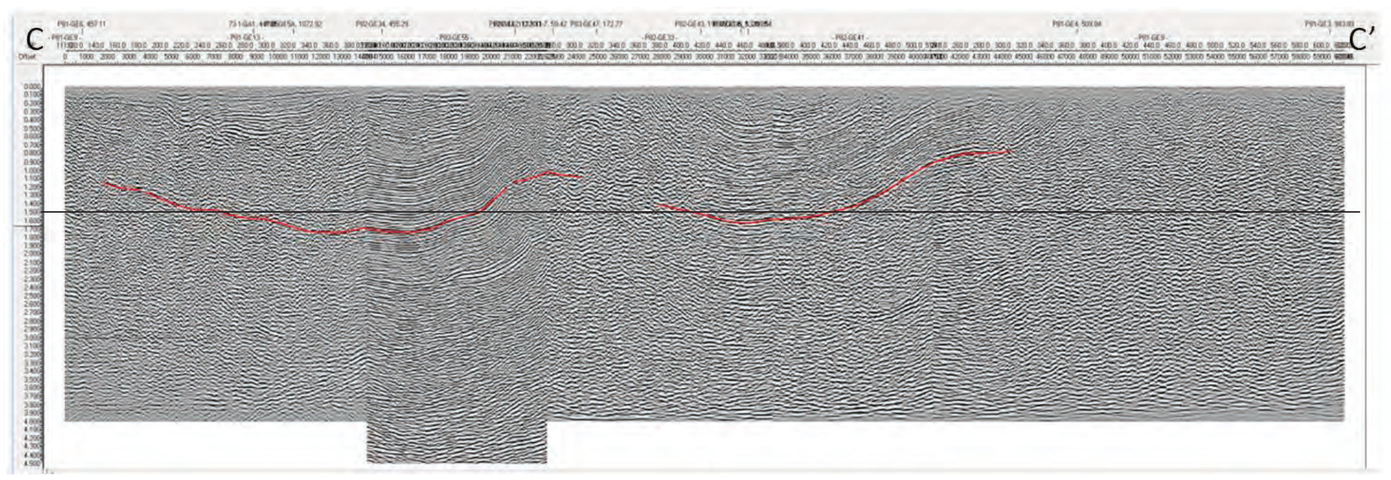


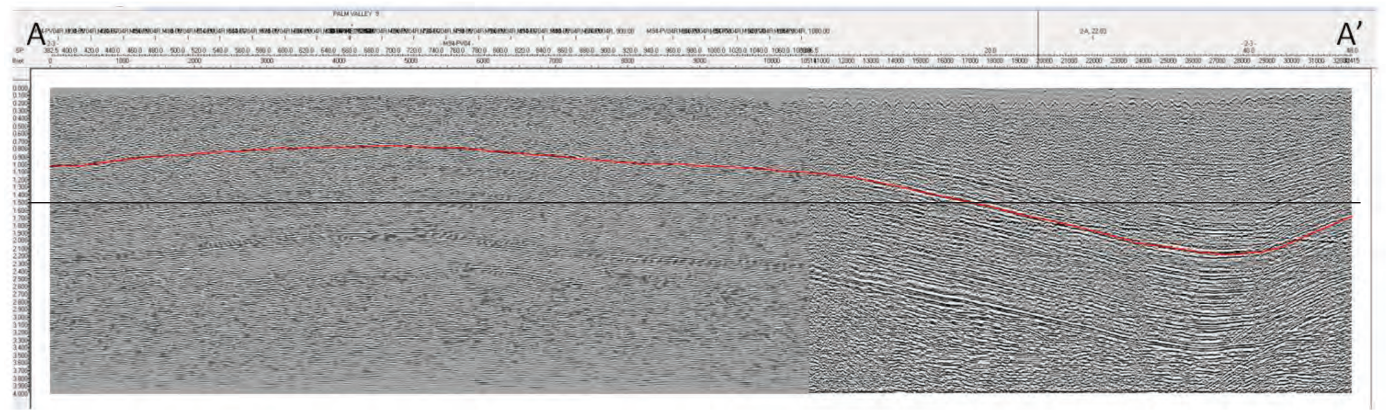


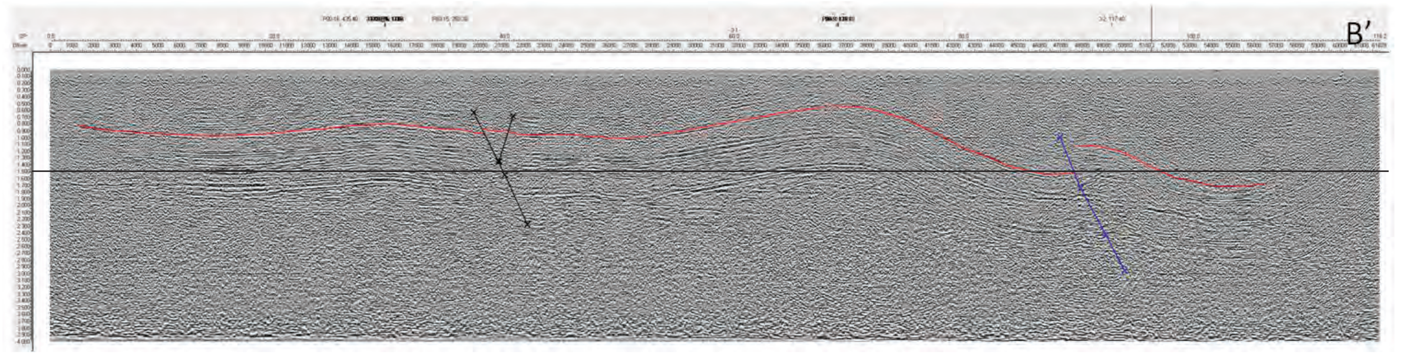
HORN VALLEY SILTSTONE CONTINUOUS HYDROCARBON ASSESSMENT UNITS

BASED ON TOP PACOOTA STRUCTURE MAP AND HORN VALLEY SILTSTONE MATURITY MAP



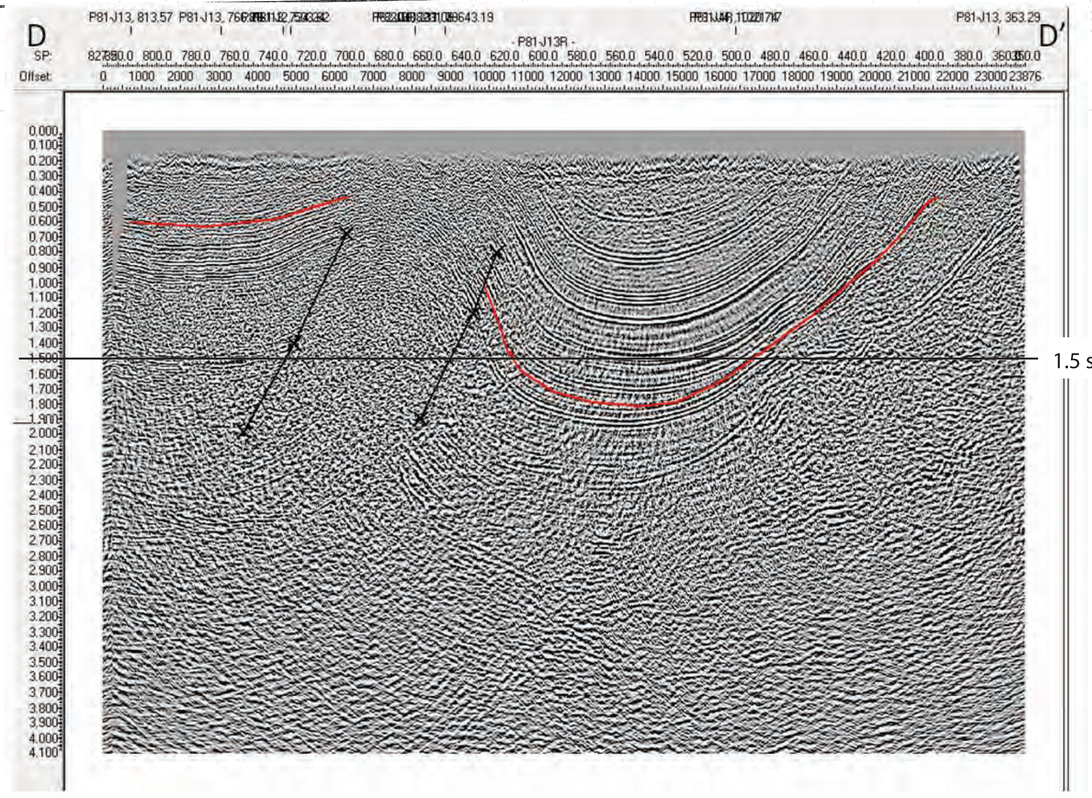


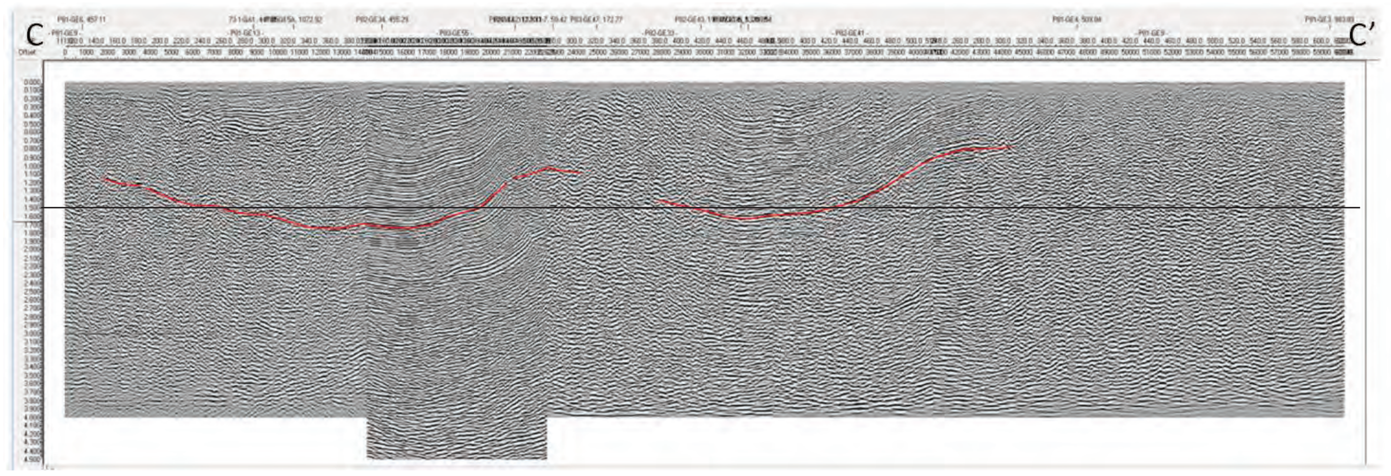


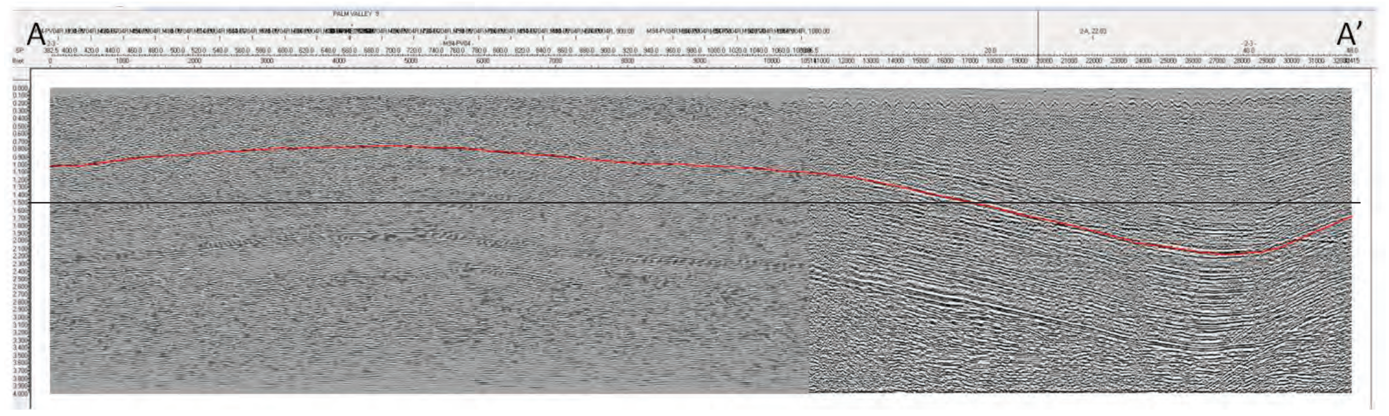


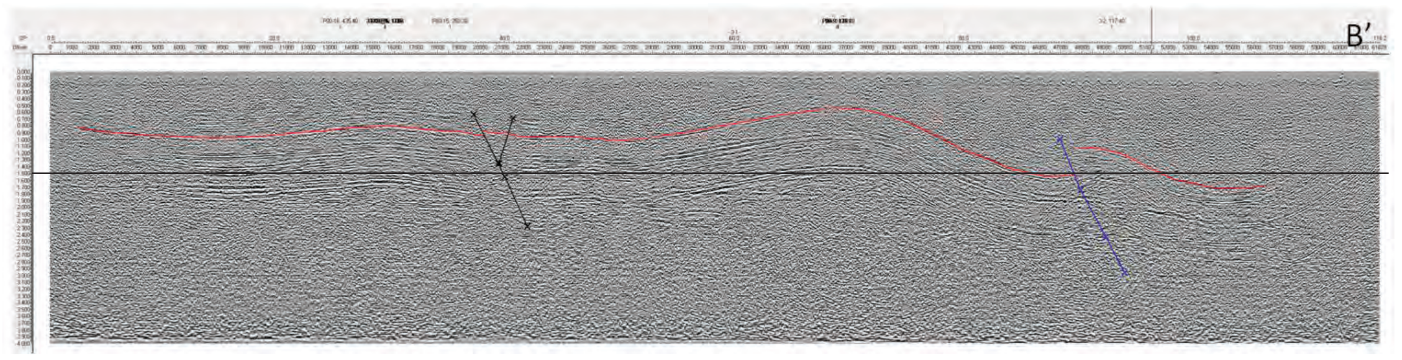
PACOOTA SANDSTONE CONTINUOUS GAS ASSESSMENT UNIT

BASED ON TOP PACOOTA STRUCTURE MAP AND HORN VALLEY SILTSTONE MATURITY MAP









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Lower Larapinta Group

Unconventional hydrocarbon resource study

A report for

Central Petroleum

Prepared by Josh Bluett

21 January 2011

Document No.: 1
(Revision 2)

petroleum consultants
an AWT Group Company

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1. EXECUTIVE SUMMARY

The objective of this report work was to provide inputs for a potential resource assessment of the Lower Larapinta Group Total Petroleum System (TPS) by other parties.

A series of maps and a regional cross-section were produced to provide the vertical and horizontal dimensions of continuous hydrocarbon play areas.

A summarised table of the continuous hydrocarbon assessment areas is presented below.

Assessment unit	Continuous hydrocarbon assessment area (km^2)	
	Oil	**Dry gas**
Stairway Sandstone continuous gas AU	**-**	**3440**
Horn Valley Siltstone continuous oil AU	**7031**	**-**
Horn Valley Siltstone continuous oil AU	**-**	**7395**
Pacoota Sandstone continuous gas AU	**-**	**3440**

2. OBJECTIVES

The objective was to define and measure the continuous (unconventional) hydrocarbon assessment units of the Lower Larapinta Group (Horn Valley Siltstone, Stairway Sandstone and Pacoota Sandstone) total petroleum system (TPS) leading to a potential resource estimate. In order to do this, three main deliverables were produced:

1. Subdivide Lower Larapinta Group TPS into assessment units
2. Provide distribution area of each assessment unit
3. Provide thickness of lithotypes in each assessment unit

3. Deliverable 1: Subdivide Lower Larapinta Group TPS into Assessment Units

3.1 Methodology

Well completion reports and mudlogs were collected and inspected for available wells. A spreadsheet (see in Appendix) was then populated with formation tops, thicknesses, oil, gas and water shows and an SMT Kingdom project was set up with well and seismic data. All data was provided by Central Petroleum. A regional geologic cross-section (A-A') was produced with composite logs of 12 wells across a region defined by Gorter (1984) as where the Horn Valley Siltstone is thermally mature for hydrocarbons (oil and gas mature), with an additional oil-mature area in the west as defined by Central Petroleum. The cross-section was created to display the distribution and nature of fluids recovered. A normalised gamma ray and sonic log track was set up to show potential organic-rich zones within the target formations. The gamma ray curve was normalised based on maximum log response over the Lower Larapinta Group.

3.2 Results

The assessment units (AU) were defined stratigraphically as the three formations of the Stairway Sandstone, the Horn Valley Siltstone and Pacoota Sandstone. The rationale of defining the assessment units based on their dominant lithology applies (as in stratigraphic nomenclature) because the distribution and genetic characteristics of rocks is likely to differ (particularly TOC), and is thus likely to affect the potential storage and production characteristics. The unconventional continuous hydrocarbon assessment units of the Lower Larapinta TPS are as follows:

1. Horn Valley continuous oil AU
2. Horn Valley continuous gas AU
3. Stairway Sandstone continuous gas AU
4. Pacoota Sandstone continuous gas AU

4. DELIVERABLE 2: PROVIDE DISTRIBUTION AREA OF ASSESSMENT UNITS

4.1 Methodology

A map for each of the four assessment units was produced by modifying the 1982 Pancontinental Petroleum Top Pacoota TWT structure map. Shows particularly indicative of the presence of continuous hydrocarbon accumulation were plotted on the well locations along with 4 regional seismic trends. The Horn Valley Siltstone continuous hydrocarbon assessment map was produced using the polygons of oil and gas windows presented by Gorter (1984), with additional polygons in the western area supplied by Central. These were checked for consistency with well shows, to define continuous oil and continuous gas zones.

4.2 Results

Water shows in the Pacoota and Stairway Sandstone within many of the wells prompted the decision to define the 1.5-second TWT contour to be that of the dry gas window. The area of proposed continuous gas accumulation is 3,440 km^2 or 850,000 acres for each of the Pacoota and Stairway continuous gas AUs.

Hydrocarbon shows in the Horn Valley Siltstone were consistent with the hydrocarbon maturity windows in Gorter (1984), so were taken to be the extent of continuous oil and gas accumulations for the assessment. The additional western area polygons supplied by Central were taken as zones of oil maturity which is consistent with shows in the HVS of Johnstone West 1 well. The continuous oil accumulation area is 7,031 km^2 or 1,737,000 acres and the continuous gas area is 7,395 km^2 or 1,826,000 acres.

5. DELIVERABLE 3: PROVIDE THICKNESS OF LITHOTYPES

5.1 Methodology

The assessment units consist of a number of lithologies which have different TOC, fluid storage mechanisms and production characteristics. In order to do the resource calculation it was deemed necessary to divide the three formations into three lithotypes: shale, tight sandstone and mixed lithology. On the regional geologic cross-section (A-A'), the gamma ray curve in track one was coded based on log response with three colours expressing assumptions of lithologies of sandstone, siltstone and shale. These lithologies were then used to define thicknesses of three lithotypes for each formation. Uncertainty of lithotype thickness in some wells is indicated where TD was reached within the Pacoota or where formation picks are ambiguous.

5.2 Results

The lithotype delineation and thickness breakdown for the three formations are presented on the attached cross-section A-A'.

6. LOWER LARAPINTA GROUP SHOWS

A summarised collection of the wells where hydrocarbon and water shows were indicated is presented here. The detailed hydrocarbon and water show/indication data from the HVS, Stairway and Pacoota Sandstones of the wells inspected is shown in the attached spreadsheet (see Appendix).

6.1 Horn Valley Siltstone shows

6.1.1 Wells with oil shows

- East Johnnys Creek 1
- East Mereenie 1
- Mereenie 1
- Mt Winter 1
- Mt Winter 2A
- Tempe Vale 1
- Tent Hill 1
- West Mereenie 1

6.1.2 Wells with gas shows

- Johnstone West 1
- East Mereenie 1
- Mereenie 1
- Mt Winter 1
- Palm Valley 1
- Palm Valley 2
- Palm Valley 3
- Tempe Vale 1
- Tent Hill 1
- Gosses Bluff 2

6.2 Stairway Sandstone shows

6.2.1 Wells with oil shows

- Johnstone West 1
- Surprise 1
- East Johnnys Creek 1
- Mereenie 1
- Mt Winter 1
- Mt Winter 2A
- Tempe Vale 1
- West Mereenie 1

6.2.2 Wells with gas shows

- Johnstone West 1
- Surprise 1
- East Mereenie 1
- East Mereenie 2
- East Mereenie 4
- Mereenie 1
- Mt Winter 1
- North West Mereenie 1
- Palm Valley 1
- Palm Valley 2
- Palm Valley 3
- Tempe Vale 1
- Tent Hill 1
- Undandita 2
- West Mereenie 1
- Gosses Bluff 2

6.2.3 Wells with water shows

- North-west Mereenie 1
- Tent Hill 1

6.3 Pacoota Sandstone shows

6.3.1 Wells with oil shows

- East Johnnys Creek 1
- East Mereenie 2
- East Mereenie 4
- Mereenie 1
- Mt Winter 1
- Mt Winter 2A
- Tempe Vale 1
- West Mereenie 1

6.3.2 Wells with gas shows

- Johnstone West 1
- East Mereenie 1
- East Mereenie 2
- East Mereenie 4
- Mt Winter 1
- Palm Valley 1

- Palm Valley 2
- Palm Valley 3
- Tent Hill 1
- Undandita 2
- West Walker 1
- West Waterhouse 1
- Gosses Bluff 2

6.3.3 Wells with water shows

- Dingo 1
- Dingo 2
- Mt Winter 1
- Palm Valley1
- Tempe Vale 1
- Tent Hill 1
- West Walker 1
- West Waterhouse 1

7. MT WINTER 2A: LOWER LARAPINTA GROUP CORE

In order to shed some light on the lithological characteristics of the Lower Larapinta Group, it was deemed necessary to inspect and summarise the described core from the Mt Winter 2A well. This well was cored from 102m depth within the Middle Stairway Sandstone to Total Depth (TD) of 259m within the Pacoota P1 unit. An entire section of described HVS core is available. The summarised descriptions are as follows:

7.1 Horn Valley Siltstone

The HVS in this location is a 62m thick package of dark grey to black shale with limestone and dolomite horizons and laminations. It is fissile to very fissile locally. It is laminated and bedded with calcareous cement, non-calcareous in part, locally carbonaceous, argillaceous in part, locally pyritic and micro-micaceous. Calcareous/dolomite content increases down-section. The HVS contains fossiliferous sections of bivalve, trilobite, pelecypod and graptolite remains and casts.

Sedimentary structures described include: parallel bedding and laminations, dewatering structures, ripples, wavy bedding and some evidence of reworking on top of limestone sections. The depositional environment was interpreted to be primarily basinal marine with marginal marine influences at the base. Secondary structures include: numerous slickensides (some with wavy surface) and fractures associated with limestone horizons. Some fair to good fracture/vuggy porosity in dolomite at the base.

There were good oil shows within the HVS with live oil and tarry seeps in fractured limestone. Fluorescence was also observed with good petroliferous odour.

7.2 Stairway Sandstone

7.2.1 Lower Stairway Sandstone

The Lower Stairway Sandstone (LSS) is a 51m thick package of light cream to grey interbedded sandstone and siltstone with minor shaly horizons. The sandstones range from very fine to very coarse with poor to very good sorting, have siliceous cement with local kaolinitic cements and are commonly bioturbated. The section contains numerous phosphatic debris horizons, is locally pyritic and fossiliferous and displays a range of visual porosity from poor to good. Sedimentary structures include: massive bedding, parallel and wavy bedding, small dunes, low-angle cross-bedding, fluid escape structures and convolute bedding. The interpreted depositional environment in the LSS ranges from intertidal to near shore to shallow marine to beach and shoreface. Some secondary structures observed were: stylolites, fracturing and slickensides 30^{o} from horizontal.

Hydrocarbon shows in the LSS were some live oil covering the face of some slickensides and some patchy yellow fluorescence with instant white cut and residue along contacts, bedding and fractures.

7.2.2 Middle Stairway Sandstone

The cored section starts within the Middle Stairway Sandstone (MSS) at ~102m. The MSS at this location is a dark grey to light grey to cream shale with minor sandstone. The shale is fissile to sub-fissile, occasionally massive and micaceous in part. The sandstone is fine to very fine with calcareous cement common, is frequently bioturbated, finely laminated and thinly bedded. The MSS contains fossiliferous phosphatic horizons as in the LSS. Sedimentary structures include: parallel bedding and laminations, rip-up clasts, graded bedding and burrows. A marine to shallow marine depositional environment was interpreted for the MSS. Secondary structures include: sub-vertical fractures, slickensides and calcite infilling of vugs. It was noted that there are fault planes 5mm thick of crushed shale and soft argillaceous material with rare pyrite crystals. No hydrocarbon shows were recorded in the MSS.

7.3 Pacoota Sandstone (P1 unit)

The Pacoota Sandstone P1 unit was intersected at 246m and continued to TD at 259m. A total of 13m was described. The section consists of light grey to dark grey siltstone and sandstone with dark grey to black shale. The siltstone was described as dolomitic, very hard, glauconitic, locally argillitic, locally ferruginous and pyritic with minor dark lithics. The sandstone is fine to very fine siliceous/quartzose, with moderately to well sorted subangular to angular grains. There was some ferruginous sandstone with nodular iron rich grain and iron oxide cements. The shale was described as micromicaceous, dolomitic with trace phosphatic nodules.

Sedimentary structures include: bedding and lamination (massive, wavy and parallel), convoluted/mixed sediments, bioturbation, possible channel features, erosional surfaces, rip-up clasts, shale lenses, aeolian? dune foresets in the ferruginous sandstone. Depositional environments interpreted for the Pacoota are shallow marine, intertidal, restricted marine, beach and arid dune. Secondary structures observed in the Pacoota are: pyrite nodules and stylolites.

The hydrocarbon show in the Pacoota P1 unit was dull yellow fluorescence in a sandstone with poor porosity and a light brown stain. The fluorescence had instant very pale white cut with slow streaming yellow cut, no colour in white light and no residual ring.

7.4 Lower Larapinta Group core analysis

Core analysis data of samples from the HVS, Stairway and Pacoota Sandstone from the Mt Winter 2A well is illustrated in the figure below. The samples were chosen based on favourable hydrocarbon and visual porosity indications. Hydrocarbon shows are evident in the HVS and the Pacoota with 25.0% residual saturation of heavy oil in the lower HVS. The porosity in these samples range from 3.7 to 10.7% and horizontal permeability ranges from 0.02 to 3.8 millidarcy.

CORE ANALYSIS
FINAL DATA REPORT

COMPANY: PANCONTINENTAL PETROLEUM LTD. COUNTRY: AUSTRALIA DATE: 19th September 1986

WELL: MT. WINTER 2A# STATE: NORTHERN TERRITORY FILE No.: CA2-55

FIELD: WILDCAT CORE INTERVAL:

Sample No.	Depth	POROSITY % He Inj	DENSITY		PERM (md) to air		Summation of Fluids & Residual Saturations			REMARKS
			Nat.	Grain	KH	KV	Ø %	Oil	Water	
1	175.93 – 176.10	5.2	2.46	–	0.96	–	–	0.0	18.8	
2	178.36 – 178.47	9.1	2.47	–	3.8	–	–	0.0	57.1	
3	179.96 – 180.20	3.7	2.53	–	0.03	–	–	0.0	51.4	
4	187.10 – 187.48	10.7	2.68	–	0.09	–	–	0.0	40.2	
5	210.20 – 210.46	5.8	2.74	–	0.02	–	–	1.7	46.6	
6	220.13 – 220.47	7.2	2.61	–	0.18	–	–	25.0	43.1	API Gravity 27.8
7	256.73 – 256.89	7.6	2.49	–	0.64	–	–	1.3	46.1	

The above figure is the core analysis report from samples taken from Mt Winter 2A. Yellow indicates samples from the Lower Stairway, green from the HVS and red from the Pacoota P1.

8. COMMENT ON JOHNSTONE WEST 1 WELL TMAX RESULTS

Seven of 12 samples from the Horn Valley Siltstone (HVS) have Tmax temperature values presented in the Amdel report. The mean temperate is 439 ^{o}C and the data has a good fit, with a spread of 8 ^{o}C. Measured Total Organic Carbon (TOC) are low, ranging from 0.3 to 1.6% however the sampling methodology has not been made explicit, so this may not be indicative of any potential high TOC horizons. The Tmax values plotted against the sampled hydrogen index data indicates type I and II kerogen that are early onset mature for oil generation. This fits with the observed good and excellent oil shows in the overlying Stairway Sandstone, and implicates the HVS as the source.

9. SUMMARY

Four continuous hydrocarbon assessment units have been delineated as the Horn Valley Siltstone continuou s oil AU, Horn Valley Siltstone continuous gas AU and the Pacoota and Stairway Sandstone continuous gas AUs, within which continuous oil or gas accumulation areas and lithotype thickness ranges have been defined. The results have been summarised in the tables below:

Average Stairway thickness	221m	Average HVS thickness	72m	Average Pacoota thickness	289m
Number of samples	8	Number of samples	10	Number of samples	7
Range of total Fm thickness	97 – 399m	Range of total Fm thickness	0 – 111m	Range of total Fm thickness	114 – 421m
Range of shale thickness	0 – 199m	Range of shale thickness	0 – 102m	Range of shale thickness	0 – 114m
Range of tight sand thickness	0 – 257m	Range of tight sand thickness	n/a	Range of tight sand thickness	0 – 128m
Range of mixed lith thickness	0 – 399m	Range of mixed lith thickness	0 – 111m	Range of mixed lith thickness	0 – 268m

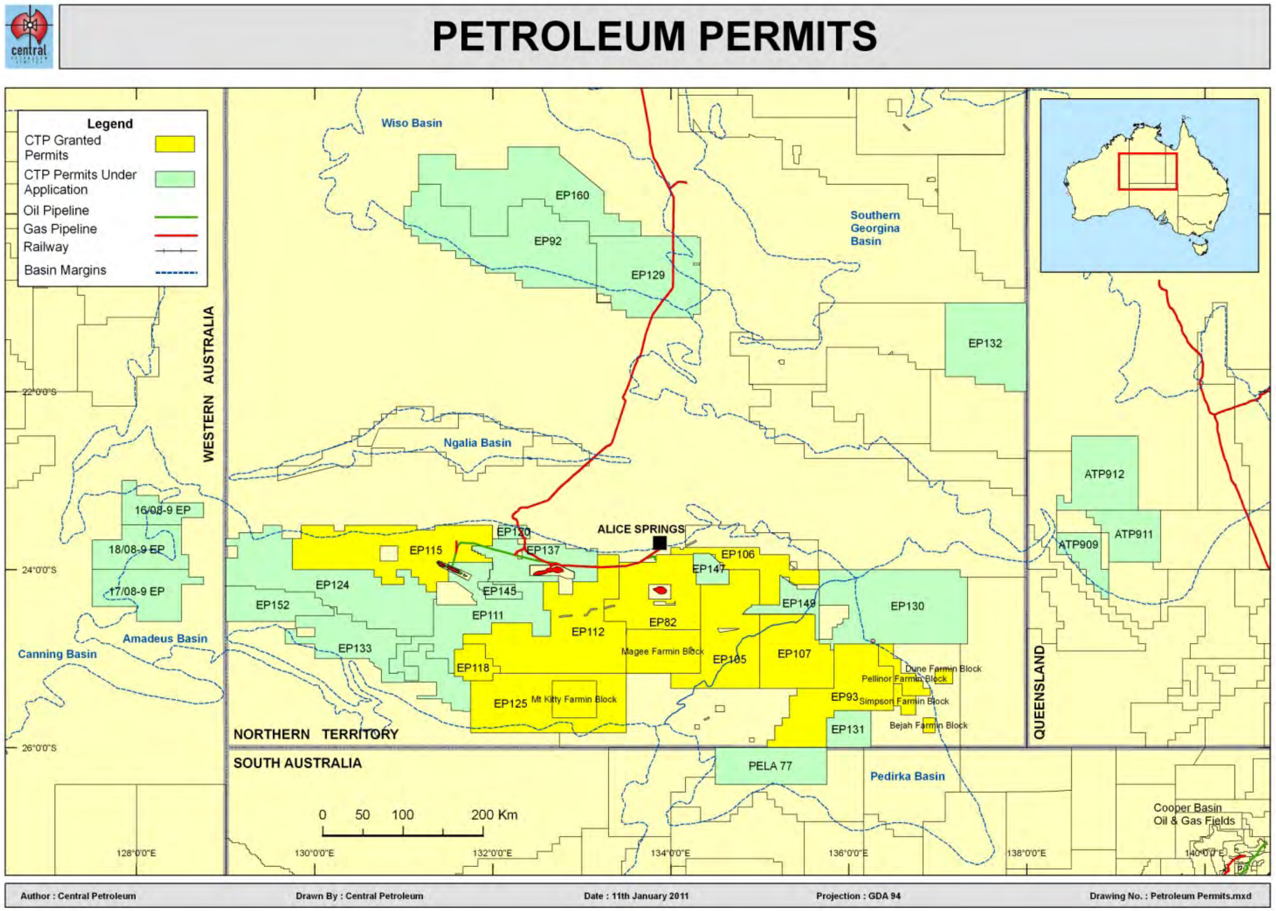
Assessment unit	Continuous hydrocarbon assessment area (km^2)	
	Oil	**Dry gas**
Stairway Sandstone continuous gas AU	**-**	**3440**
Horn Valley Siltstone continuous oil AU	**7031**	**-**
Horn Valley Siltstone continuous oil AU	**-**	**7395**
Pacoota Sandstone continuous gas AU	**-**	**3440**

Amadeus Basin

Lower Larapinta Group

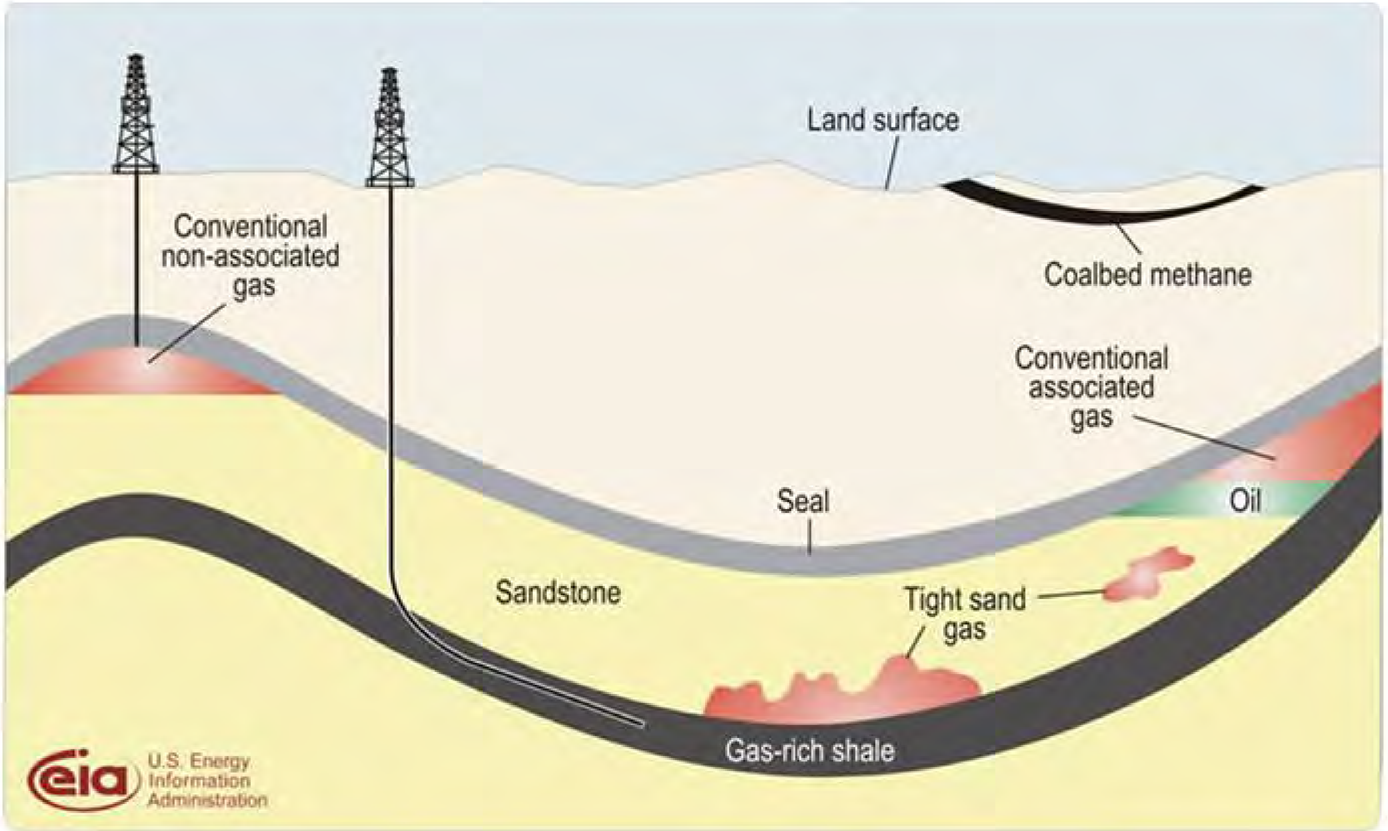
Unconventional Play Assessment

Central Petroleum and The Amadeus Basin

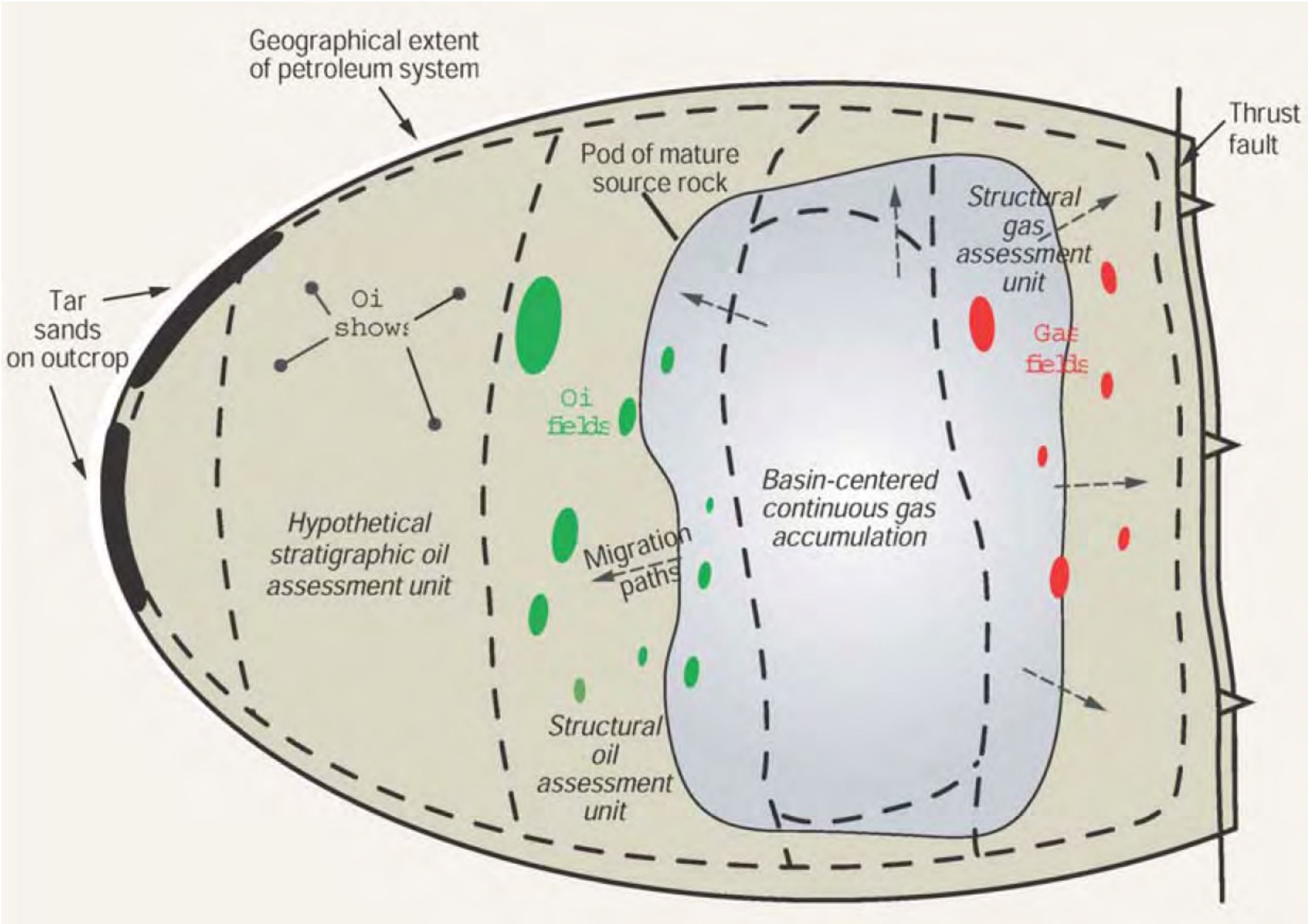


AU	P90 Low	Mean Mean	P10 High	Resource Classification
Stairway Continuous Gas AU	1.1	5.1	10.5	Prospective (Recoverable) Resource TCF
Horn Valley Continuous Gas AU	2.6	11.3	23.8	Prospective (Recoverable) Resource TCF
Pacoota Continuous Gas AU	2.4	9.8	19.7	Prospective (Recoverable) Resource TCF
Total Gas all gas AUs		26.2		
Horn Valley Continuous Oil AU	0.207	1.14	2.5	Prospective (Recoverable) Resource Billions of BBLS

Methodology


Land surface
Conventional non-associated gas
Coalbed methane
Conventional associated gas
Seal
Oil
Sandstone
Tight sand gas
Gas-rich shale
U.S. Energy Information Administration

Petroleum Systems and Assessment Units



Lithotypes

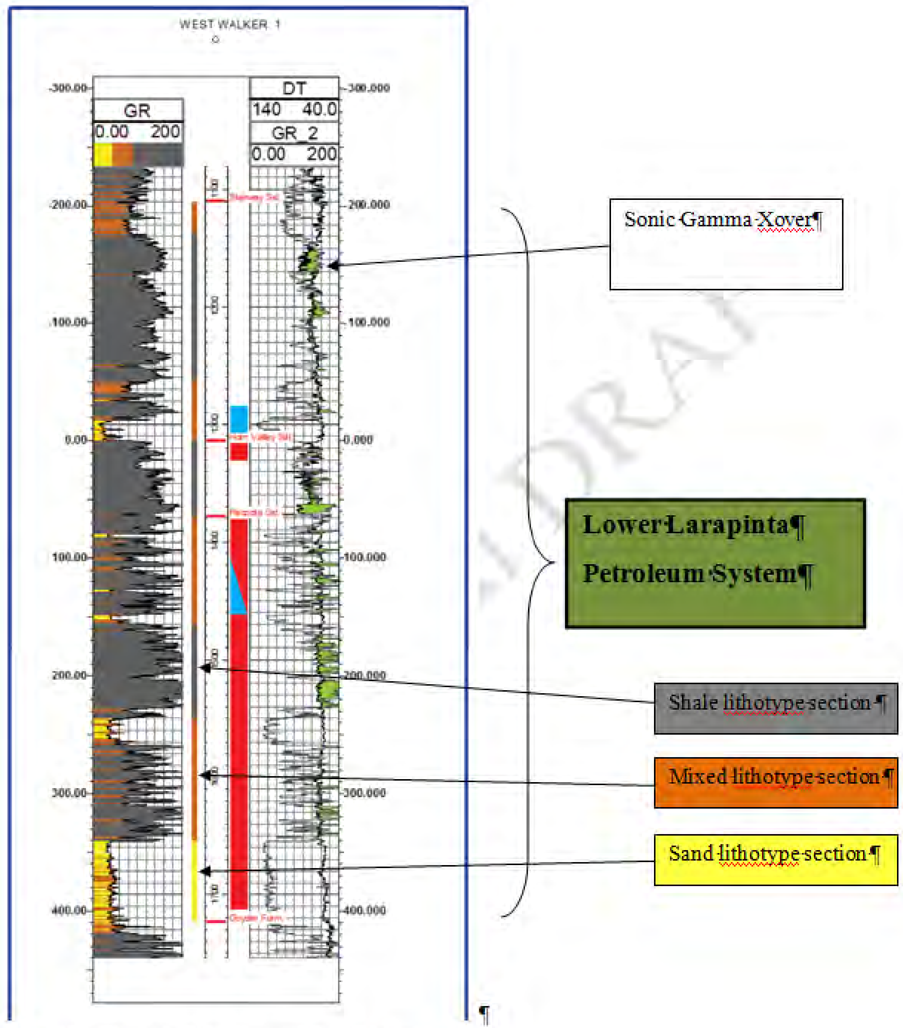
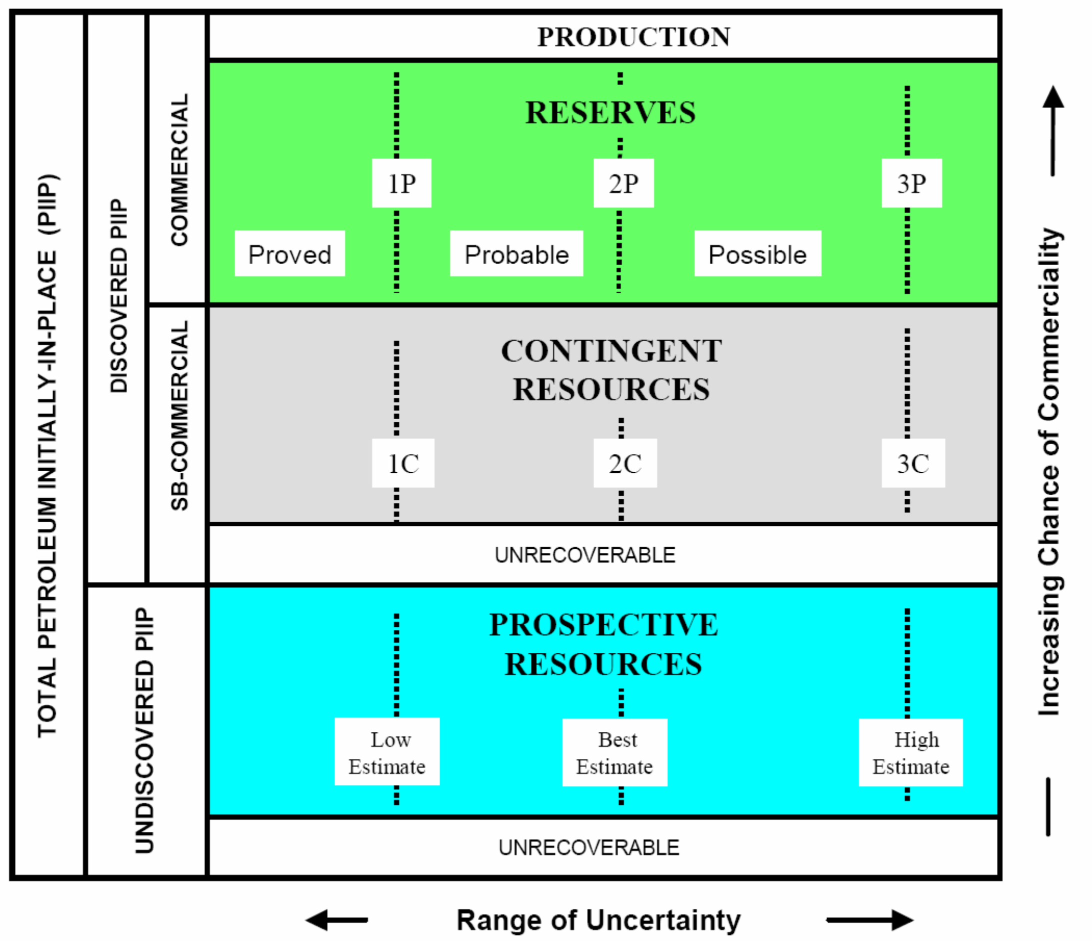
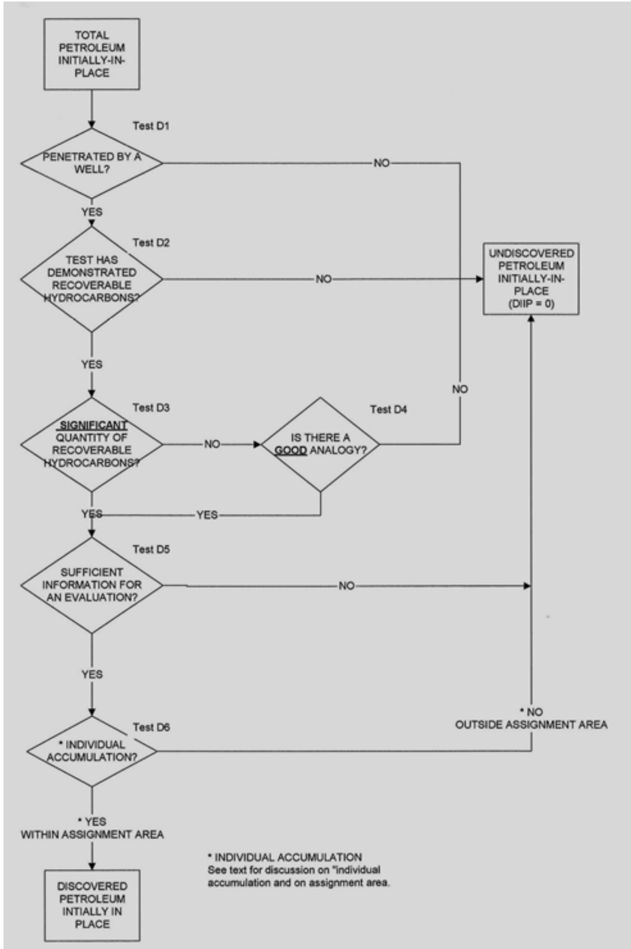


Figure 9 Lower Larapinta Type Section - West Walker 1

PRMS Classification System

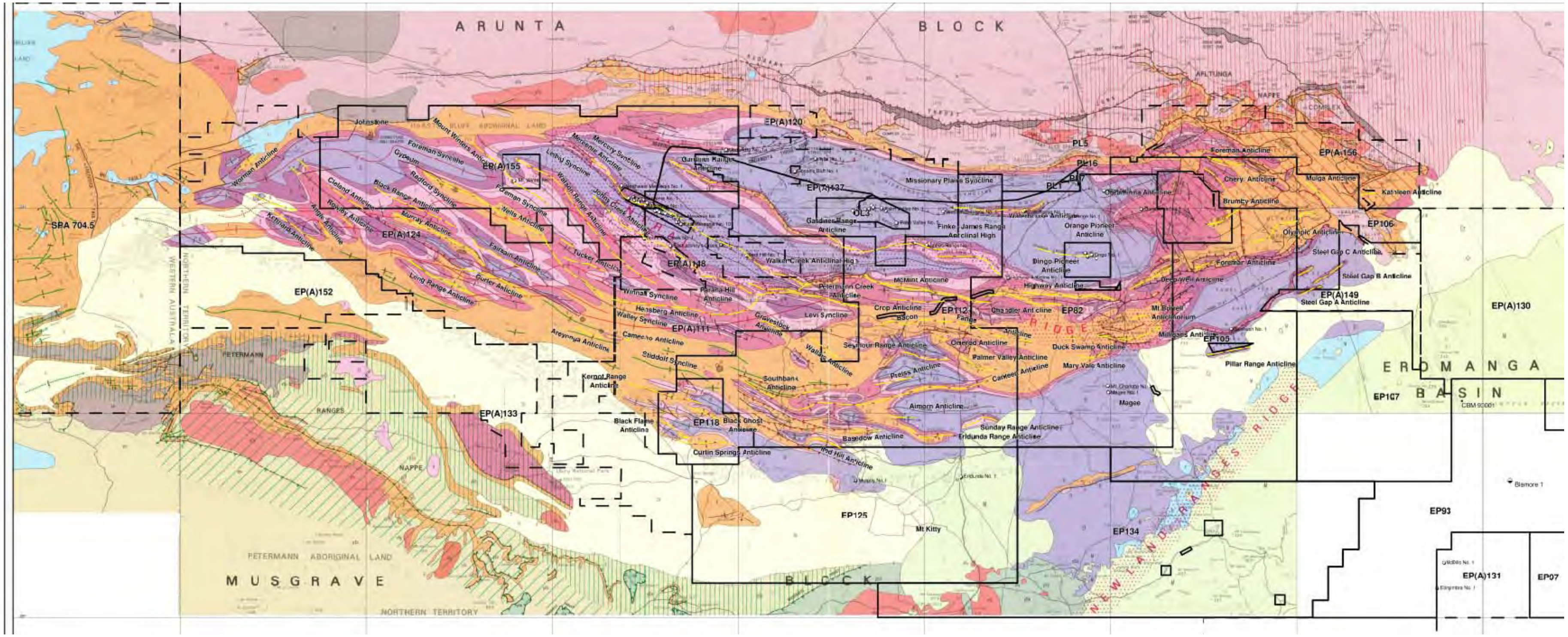


Is your resource Discovered?



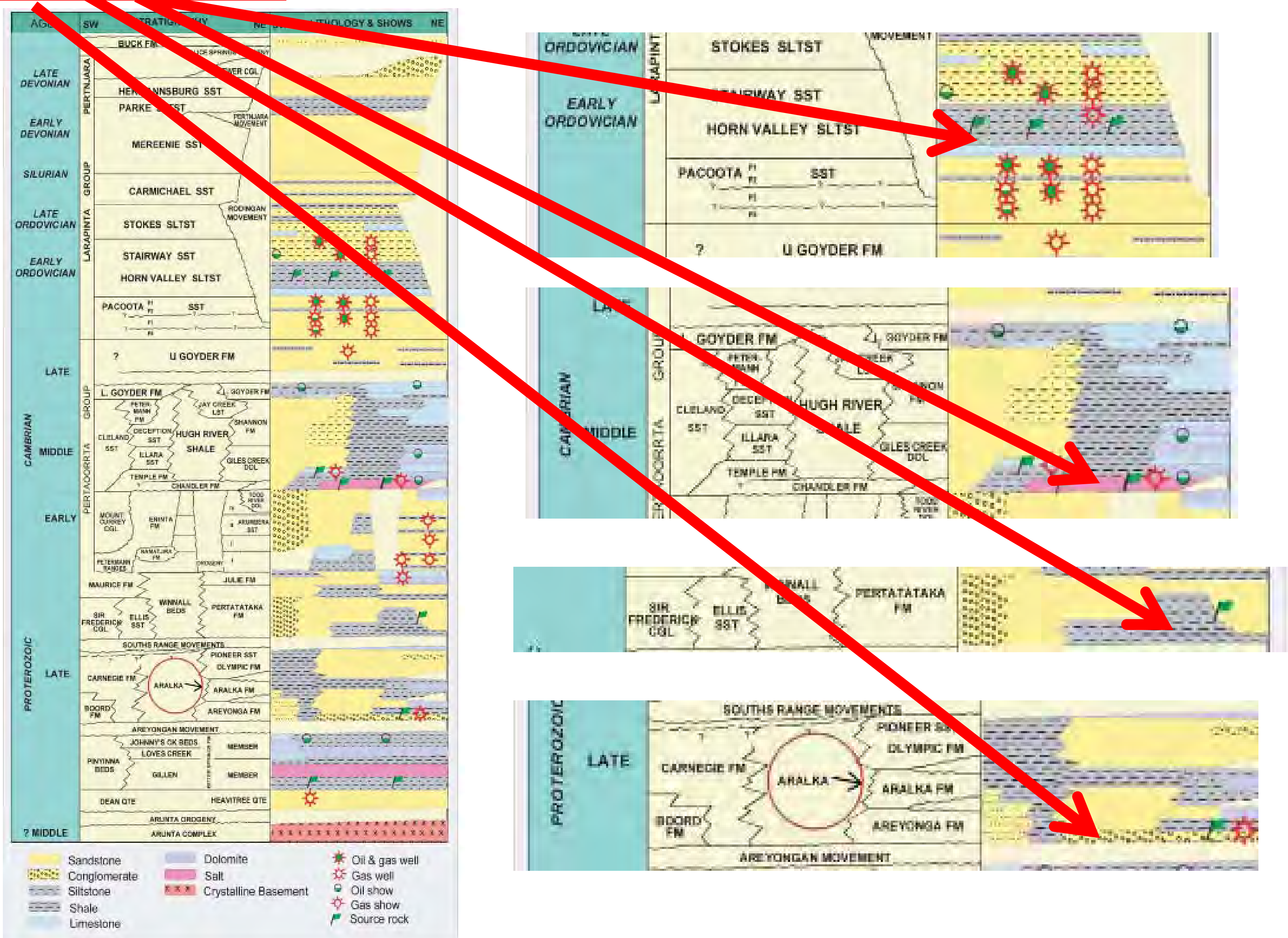
Regional Analysis

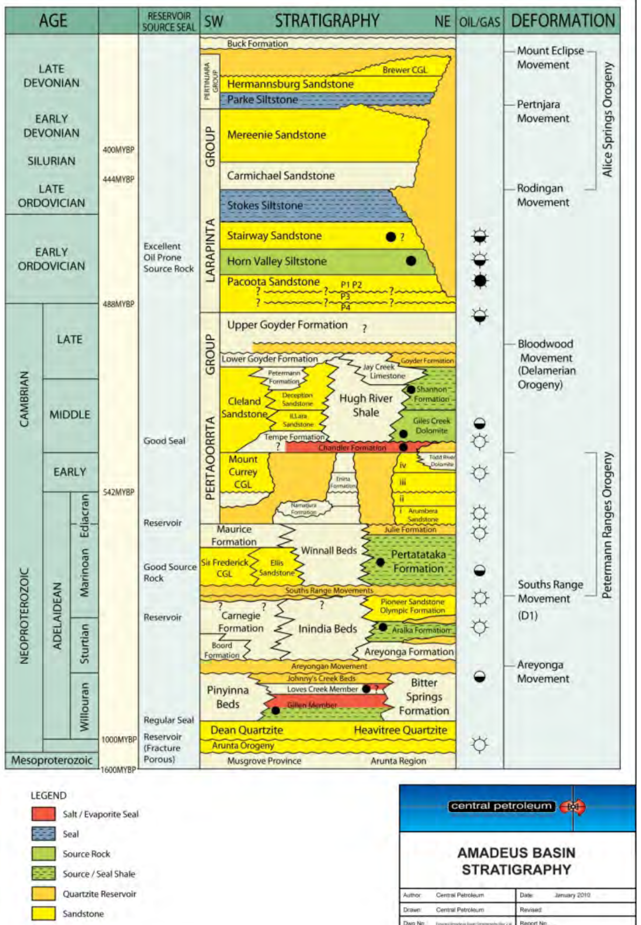
Amadeus Basin



Amadeus Source Rocks

Target Shale Play

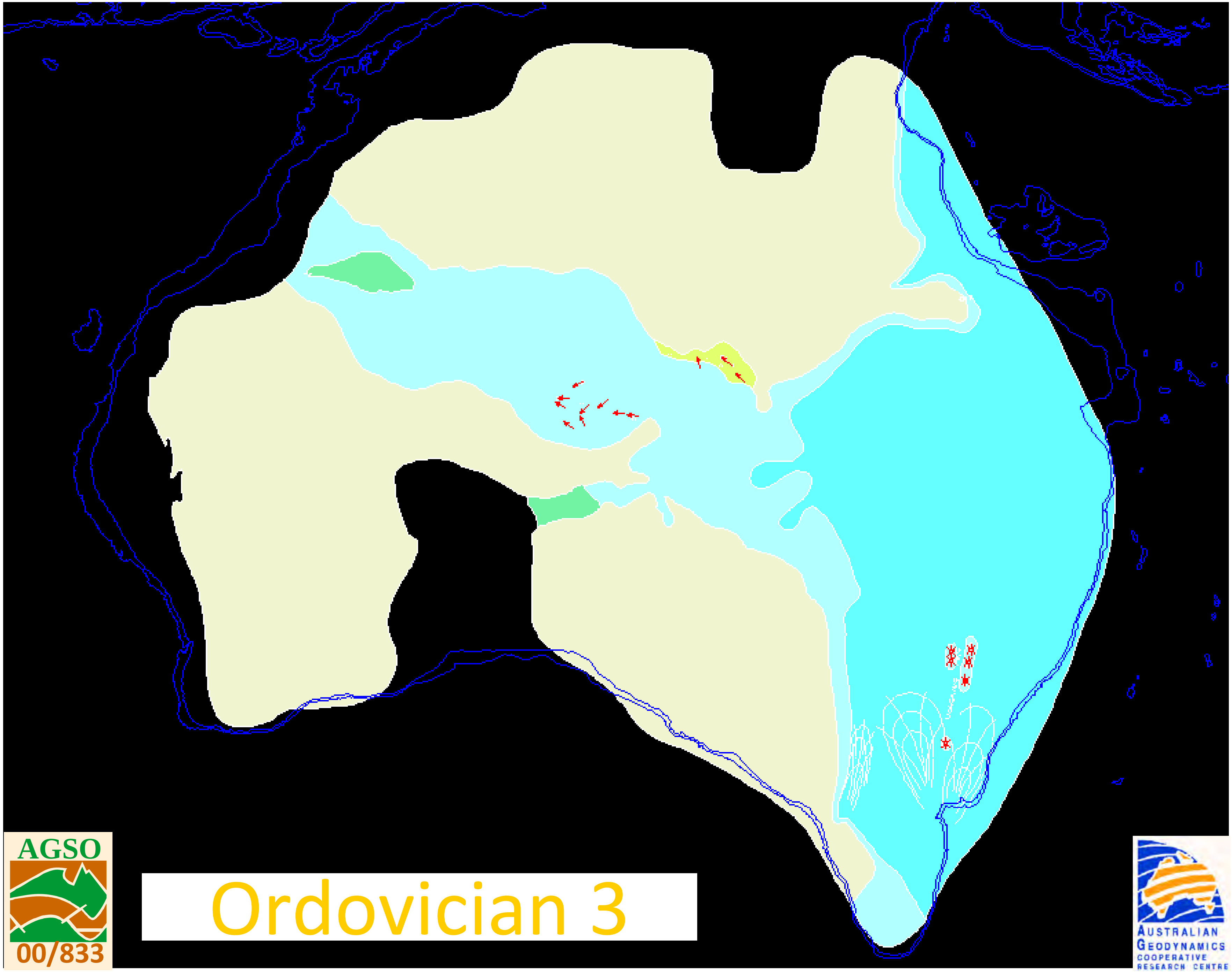




central petroleum

AMADEUS BASIN STRATIGRAPHY

Author:	Central Petroleum	Date:	January 2010
Drawn:	Central Petroleum	Revised:	
Dwg No.:	[illegible]	Report No.:	
Projection:		Scale:	



Ordovician 3

AGSO 00/833

Australian Geodynamics Cooperative Research Centre

Horn Valley Shale

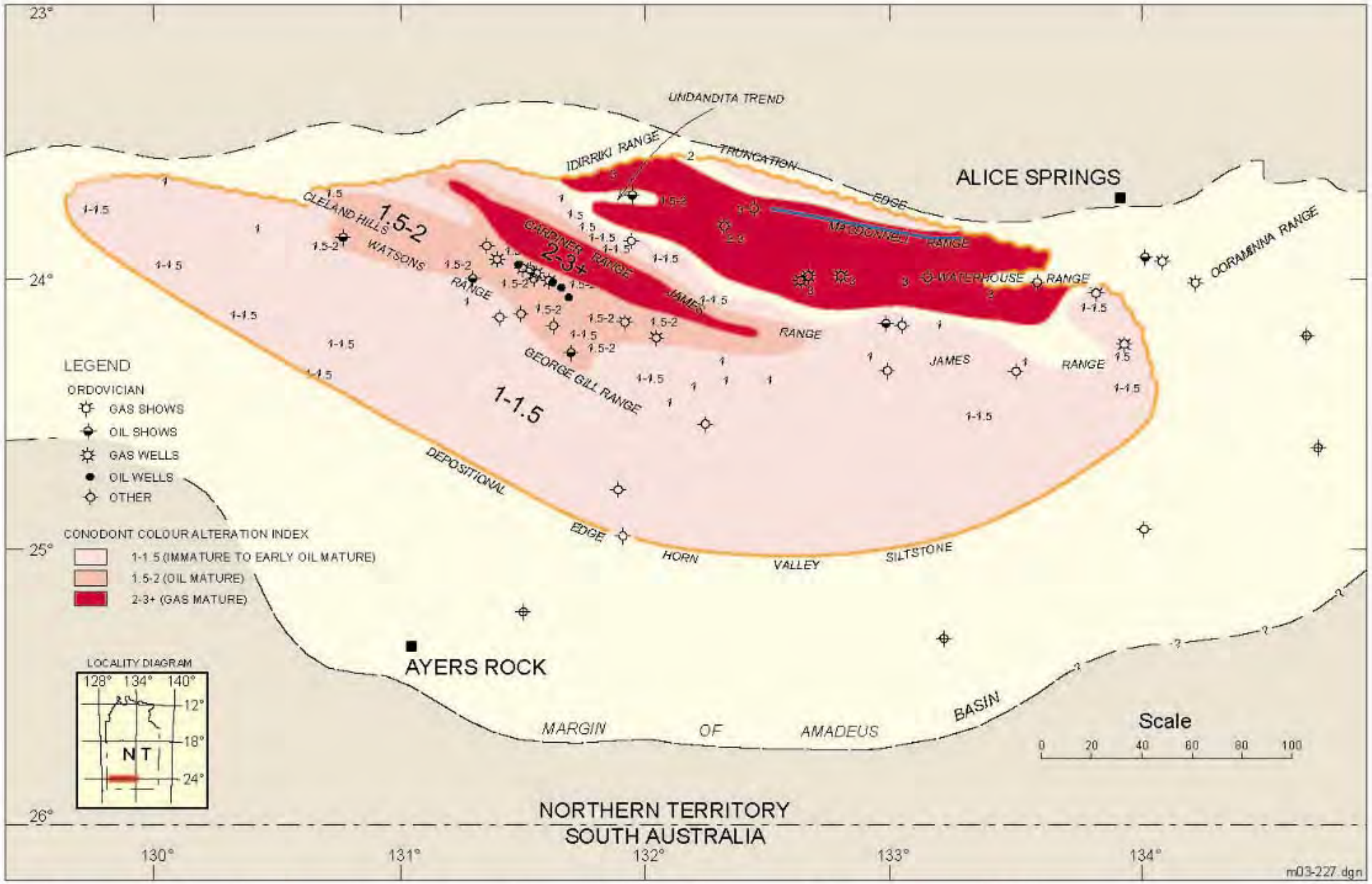


Figure 12. Distribution of maturity – Horn Valley Siltstone (after Gorter,1984).

Well Data

Lithotypes

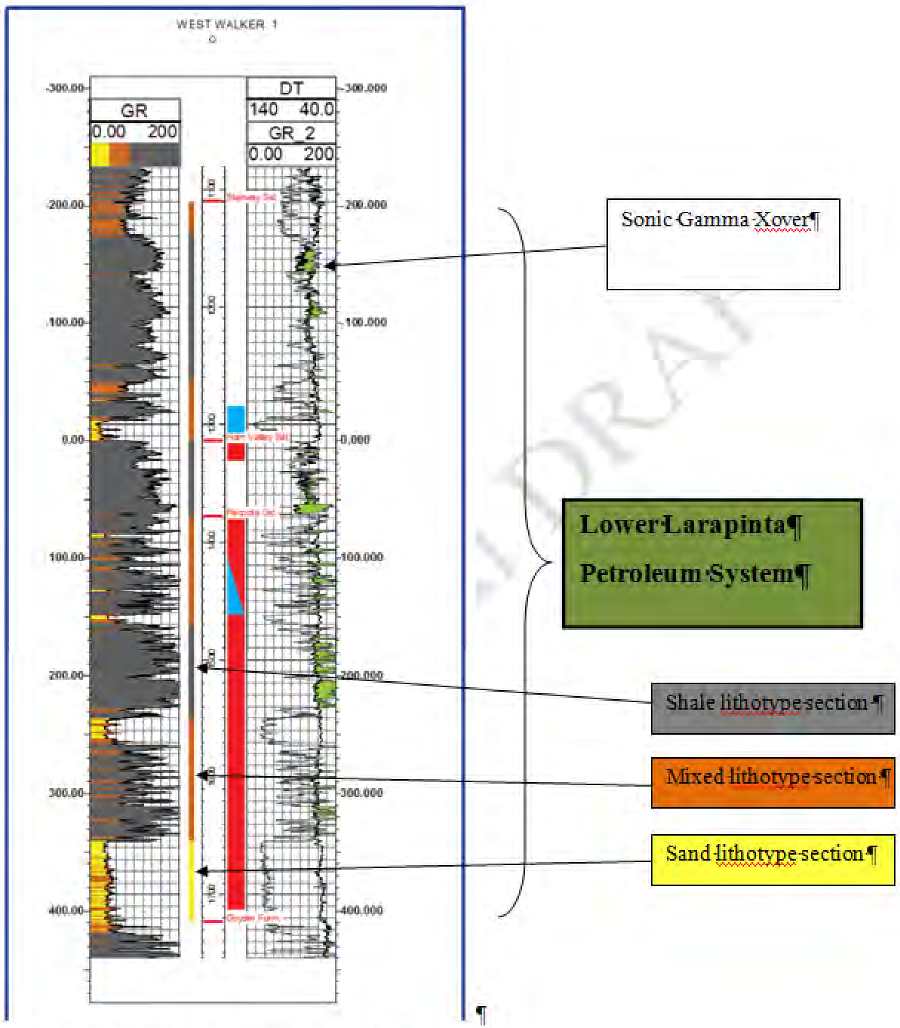
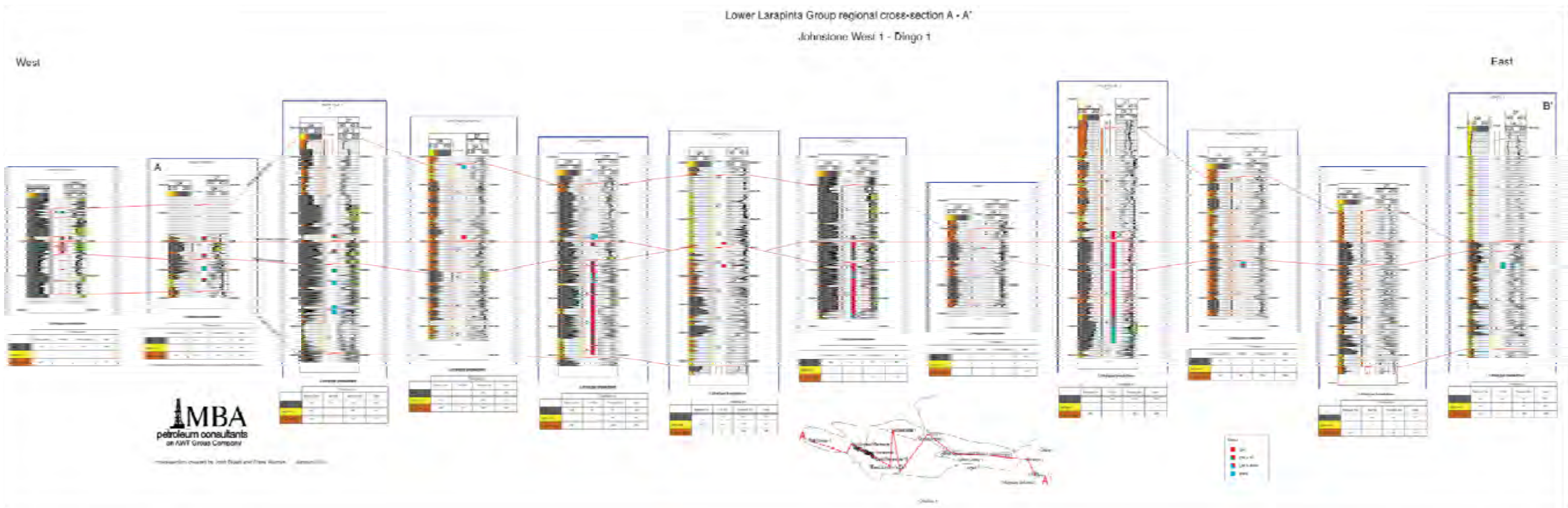


Figure 9 Lower Larapinta Type Section - West Walker 1 ¶

Lithotype Thickness Analysis

Asesssment Unit	Lithotype	Well												Thichness		
		Johnstone West 1	Mt Winter 1	Tempe Vale 1	NW Mereenie 1	West Walker 1	Undandita 1	Tent Hill 1	Tyler 1	Palm Valley 1	West Waterhouse 1	Orange 2	Dingo 1	Low	Best Guess	High
		m	m	m	m	m	m	m	m	m	m	m	m	m	m	m
HV Oil	Shale	39	35	79	0	65	0	73		102	0	84	34	5	30	75
	Tight Sandstone	0	0	0	0	0	0	0		0	0	0	0	3	5	15
	Mixed lithology	0	26	0	111	0	0	0		0	67	0	0	5	30	75
HV Gas	Shale													5	30	75
	Tight Sandstone													3	5	15
	Mixed lithology													5	30	75
Stairway	Shale	55	0	175	0	126	0	199		0	61	0		5	30	150
	Tight Sandstone	0	0	27	52	0	257	0		0	0	0		5	50	200
	Mixed lithology	42	26	158	221	78	0	0		399	167	109		5	50	300
Pacoota	Shale	114	0	81	32	81	97	177		170	36	93	39	5	30	150
	Tight Sandstone	0	28	89	22	69	128	0		0	0	0	49	5	50	100
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

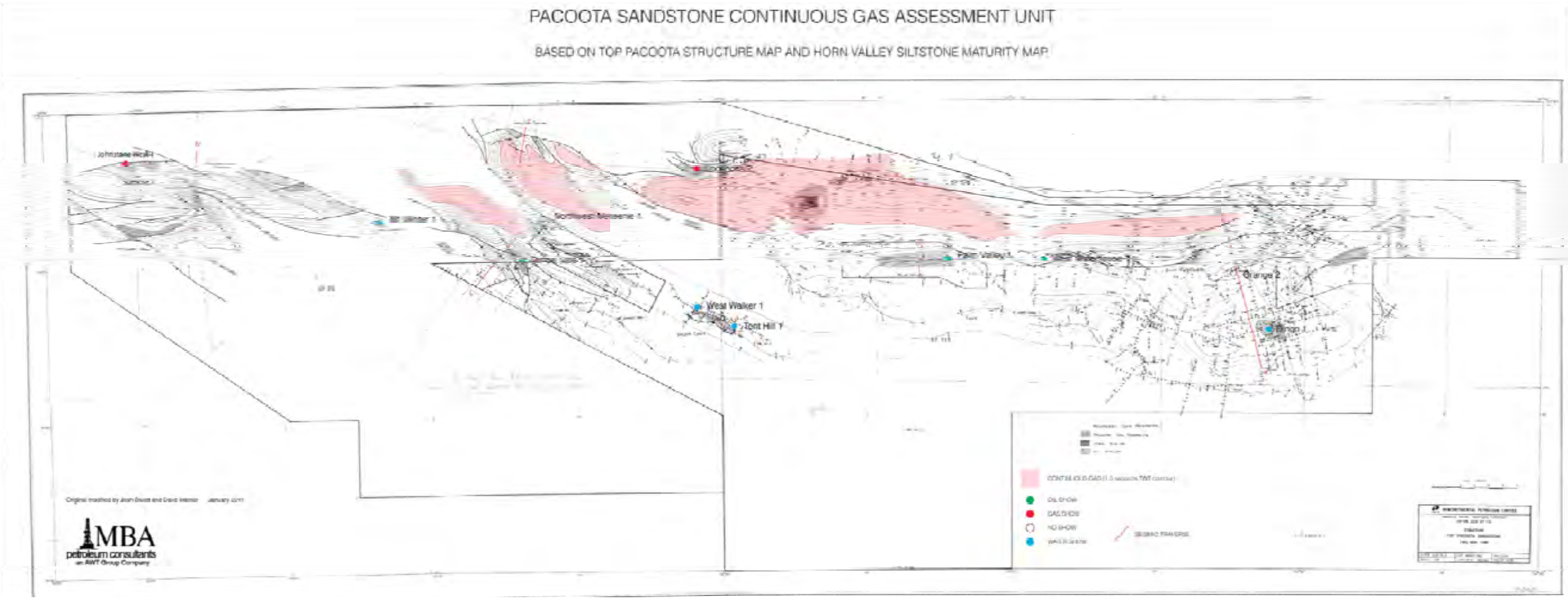
Basin Cross Section



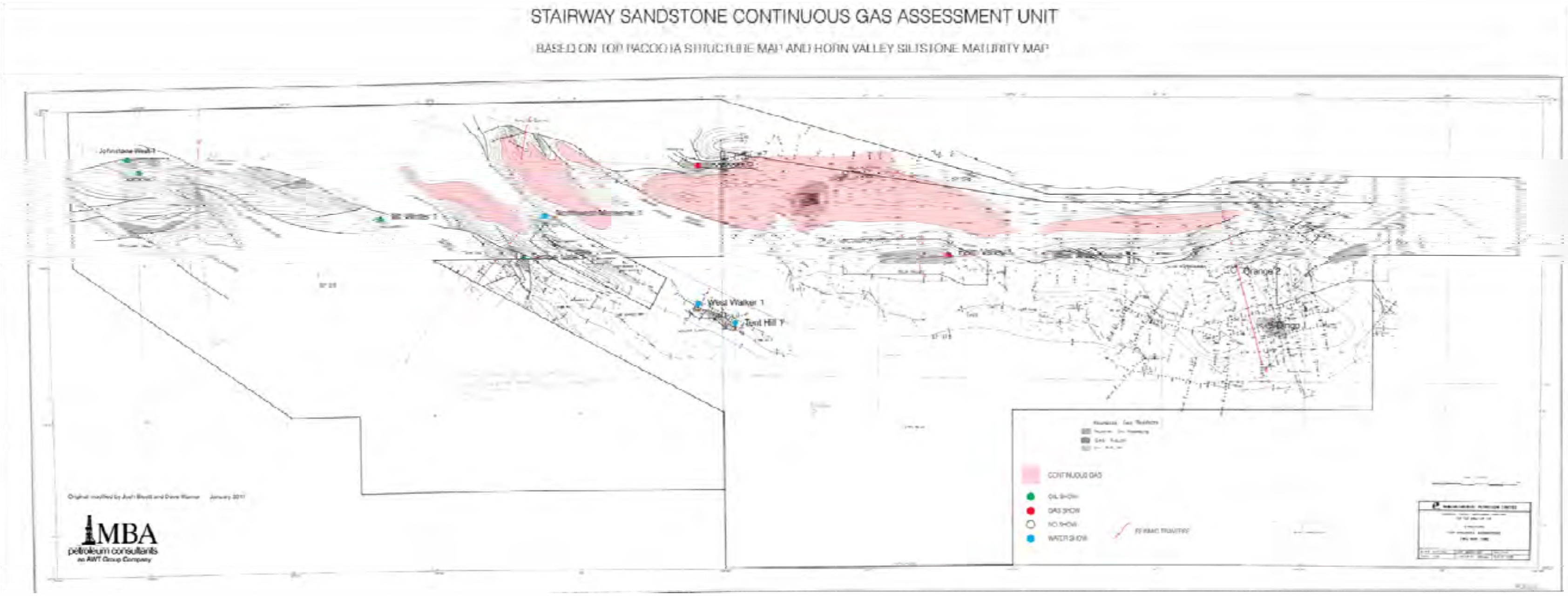
Plays or Assessment Units

Diagramatic Cross section

Pacoota Continuous Gas



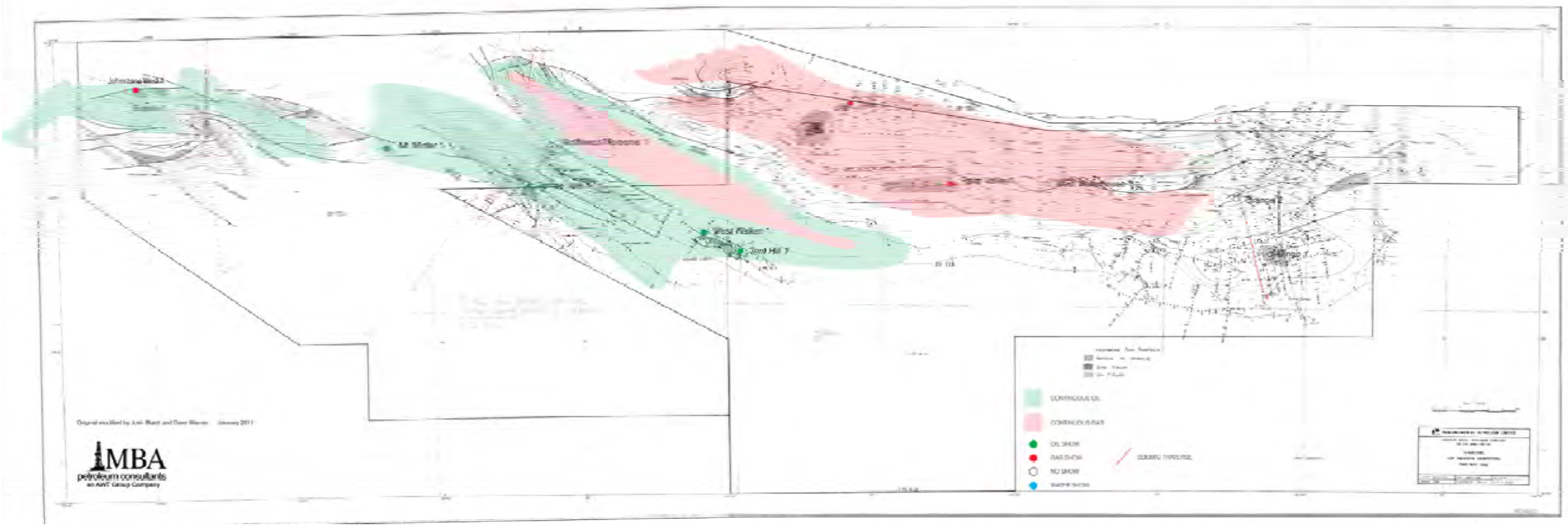
Stairway Continuous Gas



Horn Valley Continuous Gas and Oil

HORN VALLEY SILTSTONE CONTINUOUS HYDROCARBON ASSESSMENT UNITS

BASED ON TOP PACOOTA STRUCTURE MAP AND HORN VALLEY SILTSTONE MATURITY MAP



Play (AU) Areas

- Horn Valley - Continuous Gas AU - 7395 Km^2 (1.83 mill acres)
- Horn Valley - Continuous Oil AU - 7031 Km^2 (1.74 mill acres)
- Stairway Continuous Gas AU - 3440 Km^2 (0.85 mill acres)
- Pacoota - Continuous Gas AU - 3440 Km^2 (0.85 mill acres

HIP

HIP Models

Tight Sandstone Lithotype

Gas-In-Place Model

The storage mechanism in the tight sandstones is as free gas in the matrix porosity. Where open fractures occur these will also store gas, however it is most likely to be insignificant.

OGIP = 43560 * A * h *r* Φ *(1-Sw)* FVF

Oil-In-Place Model

The storage mechanism in the tight sandstones is as free oil in the matrix porosity. Where open fractures occur these will also store oil, however this volume is considered to be insignificant.

OOIP = 7758 * A * h *r* Φ_m *(1- S_{wm})* FVF

HIP Models

Shale Lithotype

Gas-In-Place Model

The shale has a combination of adsorption, related to the clays and organic content, as well as free gas in the matrix porosity. Where open fractures occur these will also store gas, however the play volume is likely to be insignificant

OGIP = $A * h*r* [\{ 43560 * FVF * ((\Phi_f * (1-S_{wf}) + (\Phi_m * (1- S_{wm}))\} + 1359.7 * G_s * \rho]$

Oil-In-Place Model

In shales oil can be stored by adsorption, related to the clays and organic content, as well as free oil in the matrix porosity. However, in shales only the free oil content is considered producible by the USGS in their assessments of oil shales. In the Lower Larapinta Shales shales the matrix porosity is considered too low to be significant as are open fracture systems.

OOIP = 0-no production

HIP Models

Mixed Lithology

Gas-In-Place Model

The mixed lithology lithotype is a mixture of thinly bedded shales and sandstones thus the lithotype have a combination of both adsorption and matrix storage. Where open fractures occur these will also store gas, however it is most likely to regionally insignificant.

The estimate for the mixed lithotype uses the same equations for the lithotypes above .

OGIP = Shale Fraction OGIP + Sandstone Fraction OGIP

Shale Fraction

$OGIP = A * h*r* [\{ 43560 * FVF * ((\Phi_f * (1-S_{wf}) + (\Phi_m * (1- S_{wm}))\} + 1359.7 * G_s * \rho]$

and

Sand Fraction

$OGIP = 43560 * A * h *r* \Phi_m *(1- S_{wm})* FVF$

Oil-In-Place Model

This lithotype is a mixture of thinly bedded shales, siltstone and sandstones thus it will have a combination of both adsorption and matrix storage. As with the other shale lithotypes the adsorbed oil and matrix content is not considered recoverable or significant and therefore is ignored. Where open fractures occur these will also store oil, however the total volume is considered insignificant.

OOIP = Shale Fraction OOIP + Sandstone Fraction OOIP

Shale Fraction OOIP = 0 -no production

and

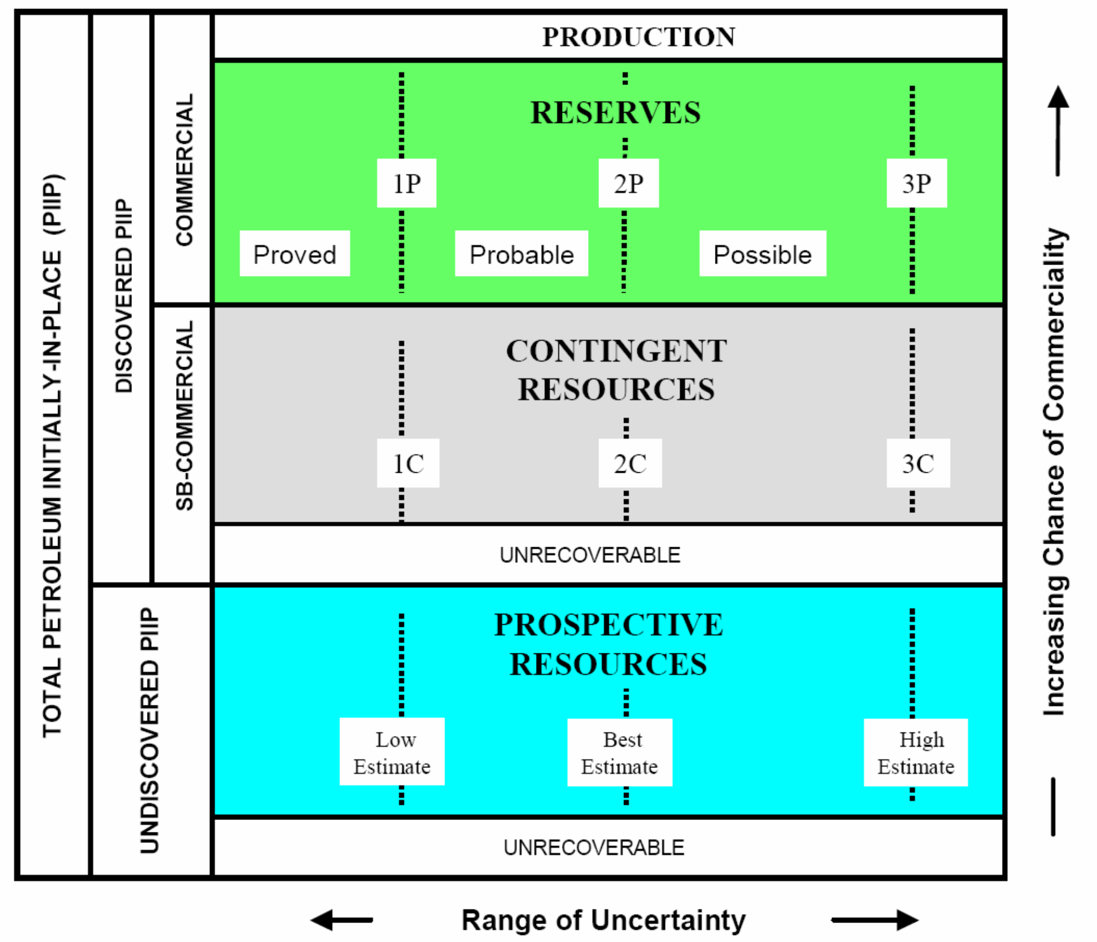
Sand Fraction $OOIP = 7758 * A * h *r* \Phi_m *(1- S_{wm})* FVF$

HIP Results

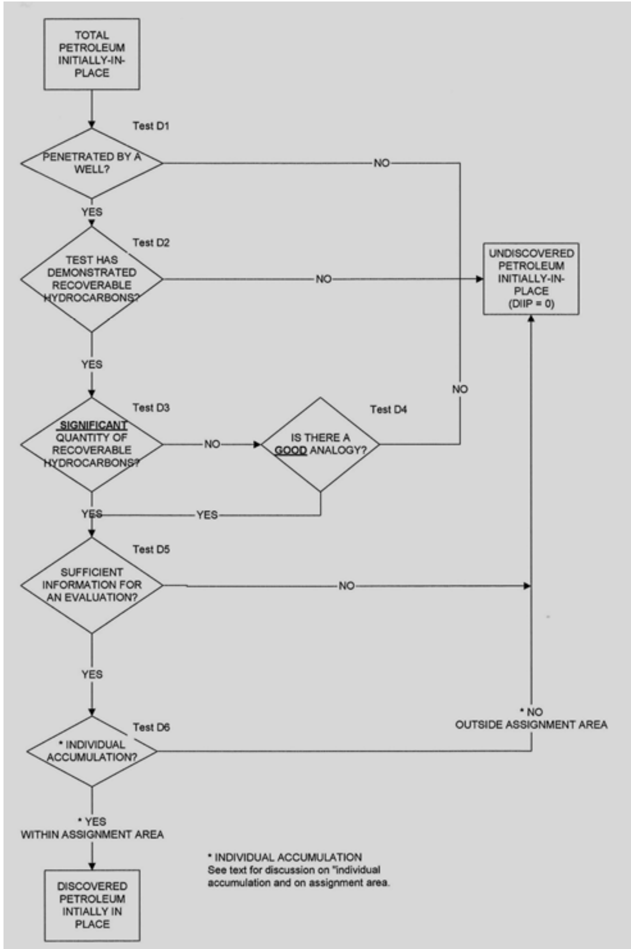
Au	HIP (TCF or Billion BBLS)			
	P90	P50	P10	Mean
Horn Valley Continuous Gas AU	7.8	20.9	56.7	27.9
Pacoota Continuous Gas AU	6.7	18.2	48.0	24.4
Stairway Continuous Gas AU	3.0	8.9	25.6	12.8
Total Gas				65.10 TCF
Horn Valley Continuous Oil AU	1.3	3.4	8.1	4.2
				4.2 Billion BBLS

HIP Classification

PRMS Classification System



Is your resource Discovered?



Recovery Factors

US Analogs

Horn Valley Continuous Oil – Bakken Shale

- Horn Valley Continuous Gas – Barnett Shale
- Stairway Continuous Gas – Mesaverde
- Pacoota Continuous Gas – Mesaverde
-

Barnett Shale

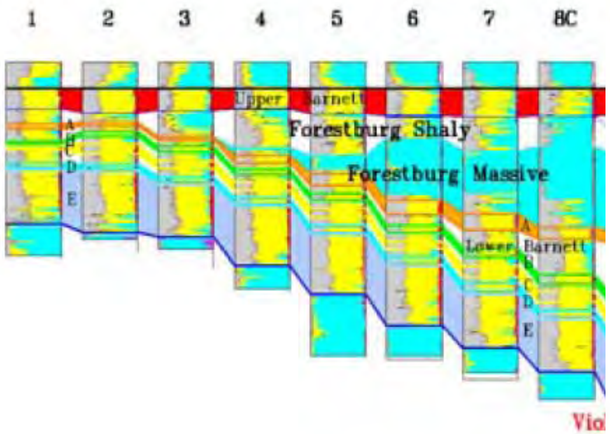


Fig. 3 – Partial stratigraphi

Mineralogy, Gas Porosity, Total Gas in Place, and Permeability

- Clay
- Carbonate
- Silicate
- Pyrite
- Organics

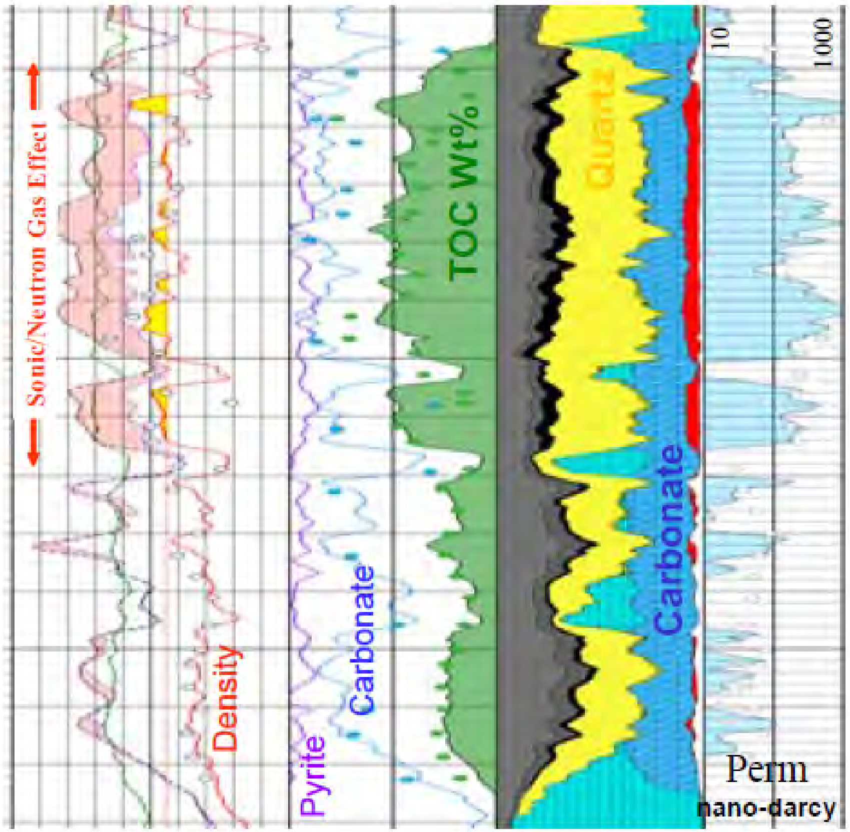
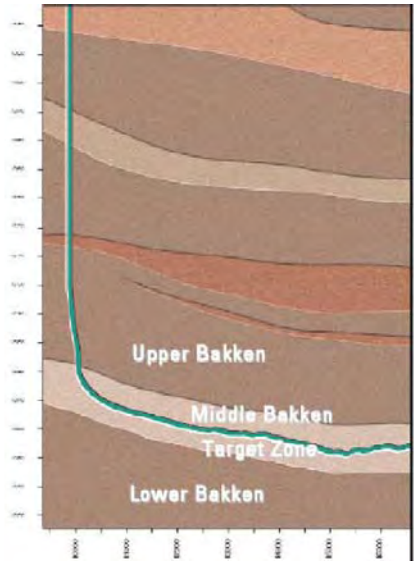


Fig. 16 – Mineralogy, gas porosity, total gas in place, and permeability.

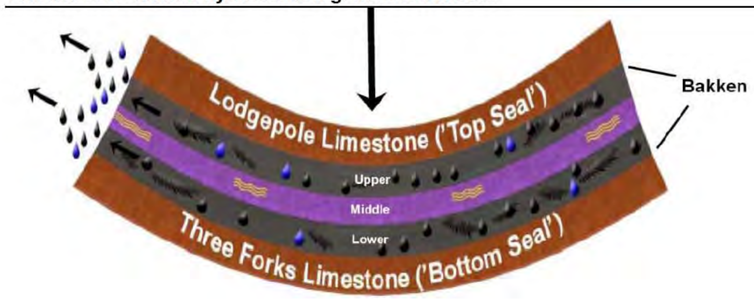
Bakken Shale



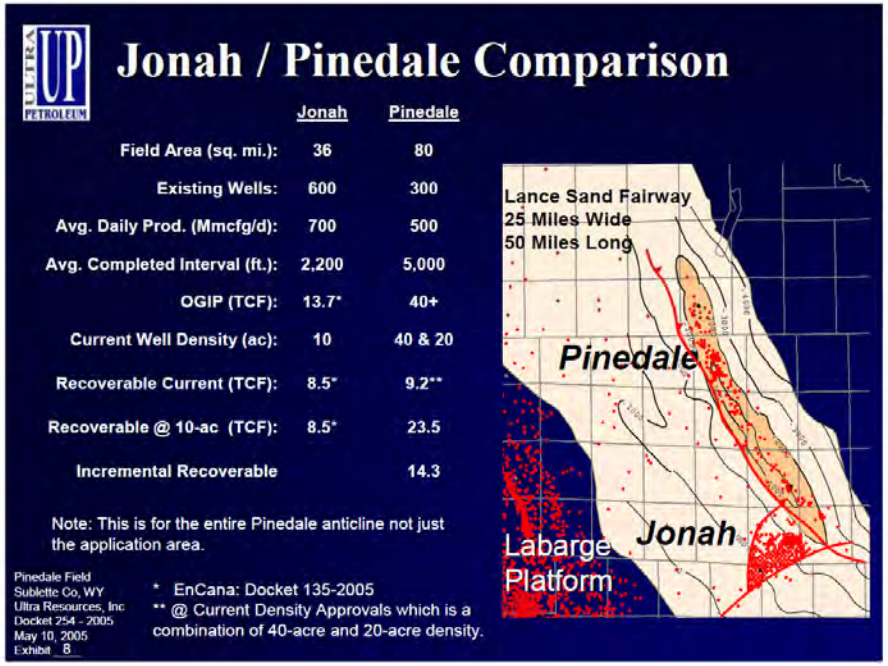
Geology

The Bakken-Lodgepole Total Petroleum System (TPS) is a distinctly homogeneous three-unit interval found extensively across the Williston Basin. The interval consists of a sandy, dolomitic Middle Bakken reservoir encased by two marine-rich shales classified as upper and lower Bakken members. Two adjacent Limestones – the Lodgepole and Three Forks – are effective seals that allowed oil to migrate laterally throughout the basin. Formation depths range from 9,000-10,500 ft, with a maximum thickness of 140 ft. The presence of natural fractures enhances productivity in some of the areas. Current activity largely targets the sandy, dolomitic Middle Bakken, which has significant variability in reservoir characteristics across the basin. Exhibit 111 depicts the Bakken hydrocarbon generation model.

Exhibit 111: Bakken hydrocarbon generation model



Mesaverde



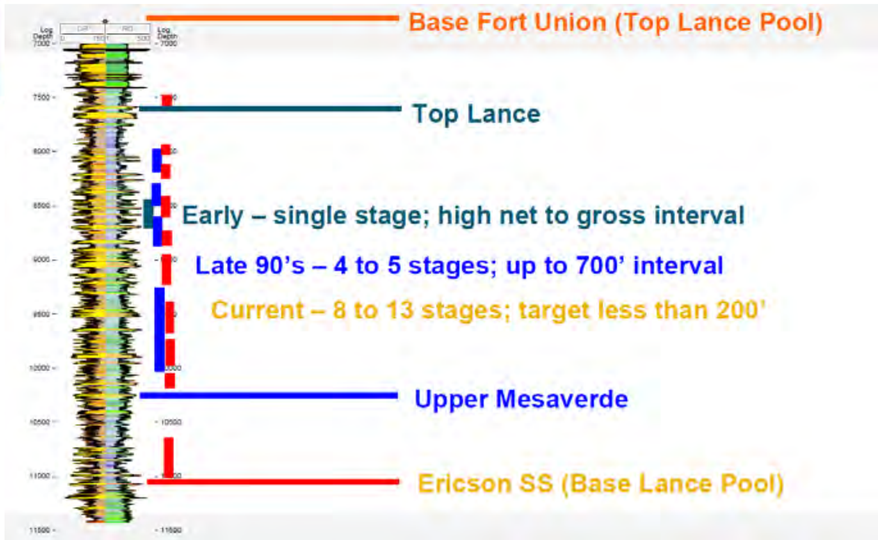
Jonah / Pinedale Comparison

	Jonah	Pinedale
Field Area (sq. mi.):	36	80
Existing Wells:	600	300
Avg. Daily Prod. (Mmcfg/d):	700	500
Avg. Completed Interval (ft.):	2,200	5,000
OGIP (TCF):	13.7*	40+
Current Well Density (ac):	10	40 & 20
Recoverable Current (TCF):	8.5*	9.2**
Recoverable @ 10-ac (TCF):	8.5*	23.5
Incremental Recoverable		14.3

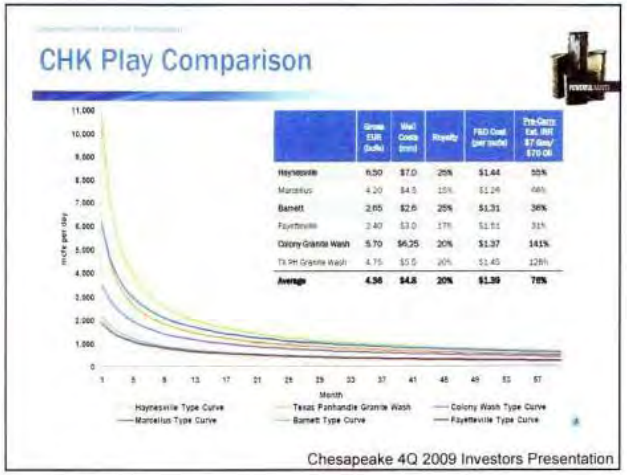
Note: This is for the entire Pinedale anticline not just the application area.

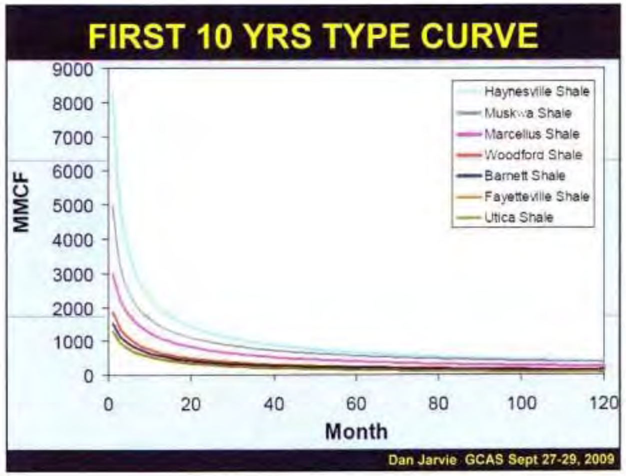
Pinedale Field
Sublette Co, WY
Ultra Resources, Inc
Docket 254 - 2005
May 10, 2005
Exhibit 8

* EnCana: Docket 135-2005
** @ Current Density Approvals which is a combination of 40-acre and 20-acre density.



Production Functions





Recovery Factors from Analogs

AU	Analog	Completion	Published RF	Spread Applied	
				P90	P50
Horn Valley Cont Gas	Barnett	Horiz with Multistage frac	20-40%	15	40
Horn Valley Continuous Oil	Bakken	Horiz with Multistage frac	5-15%	5	15
Pacoota Continuous Gas	Jonah-Mesaverde	Vertical Multistage Frac	20-40%	20	40
Stairway Continuous Gas	Jonah Mesaverde	Vertical Multistage Frac	20-40%	20	40

Technically Recoverable Resources

Technically Recoverable Resources

Assessment Unit	Prospect Recoverable Resource (TCF or Billion BBLS)			
	P90	P50	P10	Mean
Stairway Sandstone Continuous Gas AU	1.1	3.4	10.5	5.1
Pacoota Sandstone Continuous Gas AU	2.4	7.0	19.7	9.8
Horn Valley Continuous Gas AU	2.6	7.7	23.8	11.3
TOTAL GAS				25.9 TCF
Horn Valley Continuous Oil AU	0.214	0.737	2.3	1.1
Total Oil				1.1 Billion BBLS

Recomendation

Recommendations

- There is a large amount of data that has to be acquired before the resource can be considered for reclassification
- Core data which can establish a gas content over a significant area is critical
- Petrological and petrophysical data can help calibrate logs and establish a minimum gas content
- Concentrate on understanding what and where the sweet spots you wish to target are

Key References

Key References

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