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Geological Assessment

Pre-test Assessment

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Geological and Economic Assessment

West AA Wells Prospect (VOBM#1 well) and LP2 Offset Prospect (VOS#1 well)

The purpose of this note is to provide a geological and economic assessment of the VOBM#1 well which is currently being tested and the VOS#1 well which is currently being drilled by Pantheon Resources (50% working interest) in Polk and Tyler counties, Texas.

On 9 September 2015, Pantheon Resources announced that drilling operations at the VOBM#1 had been successfully concluded and that the company made the decision to case the well and proceed to flow test it using a lower cost workover rig. The company said “data from the logs indicate the presence of a potential reservoir in the Eagle Ford/Woodbine sandstone” and that “the significance of these results will not be known until flow testing operations have been completed”. Flow testing operations are expected to commence between the 20th and 24th of September 2015. The company also announced that the VOS#1 well was spudded. This well is expected to take 45-50 days to drill on a trouble free basis. The VOS#1 well has an Eagle Ford / Woodbine primary target in addition to a secondary target, the overlying Austin Chalk if the primary target is uncommercial. The Austin Chalk would be drilled with a horizontal lateral.

In the Eagle Ford formation, the company is targeting geological structures known as mini-basins which contain high quality sands that can be produced with vertical wells that do not require hydraulic fracturing. We believe the log signature of mini-basins in the Polk and Tyler counties are typically quite definitively recognizable. We believe, to have completed the well and to have made the decision to flow-test the well can be interpreted positively in the context of the objective of attempting to discover a mini-basin containing high quality reservoir sands. However, the stratigraphic mini-basins are highly heterogenous (a high degree of variability in sand quality can exist within such mini-basins). In the area, heterogenous deposition and localised calcite diagenesis can completely occlude porosity, creating a situation where highly porous rock is impermeable. There is no log for permeability. Therefore, for these mini basins it is difficult to draw hard and fast conclusions relating to commerciality from the logs alone. The company has made the prudent decision to wait until production results before commenting on commerciality. Allowing for some interpretation, our view is that it is likely that a mini-basin was discovered (porous hydrocarbon filled rock), but that it is too early to know if the rock is permeable (a key ingredient for commercial success). We develop these ideas more fully in this note.
If successful the gross best estimate recoverable resource estimates for the West AA Wells, LP2 Offset and Austin Chalk prospects are 58 million boe, 54 million boe and 43 million boe respectively. Based on our assessment to fully develop the resources would require 37, 34 and 42 wells for each of the respective prospects. The extraordinary per-well economics, assuming a success case, are provided below for conventional Eagle Ford wells and Austin Chalk wells. For perspective, wells are expected to cost circa $5.0 million for the Eagle Ford and $6.0 million for the Austin Chalk, therefore the per-well returns, in a success case can be expected to be excellent, even in the current oil price environment.

**Base Case Well Economics**

![Graph showing NPV per Well ($US Million) vs. Oil and Gas Price]($10/b & $1.66/mcf to $80/b & $4.00/mcf)

- Conventional Eagle Ford Well - Base Case
- Austin Chalk Well - Base Case

*Source: Panmure Gordon*

This note provides background on the geological and economic context of this exciting exploration campaign.
**EAGLE FORD CONVENTIONAL TARGETS**

The successful discovery of one or two conventional Eagle Ford prospects would pave the way for a large scale drilling programme with exceptionally competitive returns on capital due to the abundance of nearby infrastructure and lower quartile drilling and operating costs.

**Commercial Background and Overview**

On 30 September 2014, Pantheon announced that it had raised £18.5 million ($US 30.2 million) and in connection with that fundraise that it completed the acquisition of 57,009 net mineral acres in the Polk and adjoining Tyler Counties, East Texas. As a result of which the company acquired 50% interests in four conventional Eagle Ford exploration areas and a 25% interest in an additional exploration area. The interests are held through a JV agreement with Vision Gas Resources LLC who will operate the JV.

The prospects in the four exploration areas in which Pantheon holds 50% working interest are called West Double A Prospect, LP2 Offset Prospect, Prospect D and Core Offset Prospect, respectively.

The prospect in the exploration area in which Pantheon holds a 25% interest is called Prospect E. Prospect E is an unconventional shale target.

Pantheon paid $15.5 million for its share of the acreage and associated back costs including the costs of seismic surveys and geological and geophysical work.

**Conventional Eagle Ford Prospect Inventory**

<table>
<thead>
<tr>
<th>Drilling Status</th>
<th>County</th>
<th>Gross Prospective Scale (mmbboe)</th>
<th>% Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>West AA Wells</td>
<td>Testing (VOBM#1)</td>
<td>Polk</td>
<td>58.0</td>
</tr>
<tr>
<td>LP2 Offset</td>
<td>Drilling (VOS#1)</td>
<td>Tyler</td>
<td>53.5</td>
</tr>
<tr>
<td>Prospect D</td>
<td>n.a.</td>
<td>Polk</td>
<td>54.5</td>
</tr>
<tr>
<td>Core Offset Prospects</td>
<td>n.a.</td>
<td>Tyler</td>
<td>93.3</td>
</tr>
</tbody>
</table>

**Source** Pantheon

**Current Drilling Programme**

The JV is currently preparing to test the VOBM#1 well (West AA Wells prospect), which is expected to commence between the 20th and 24th of September. The company expects that the VOS#1 (LP2 Offset) will be completed around the 24th to 29th of October, assuming it is drilled on a trouble free basis. A horizontal lateral would be drilled into the Austin Chalk subsequently, if the primary Eagle Ford target of the VOAA#1 is not commercial.
Vision Gas Resources

Vision is jointly owned by Bobby Gray and George Kaiser.

Bobby Gray is a Managing Partner of Vision. He has 40 years of oil & gas experience with independent companies in Texas and Louisiana. He has operated in the Tyler and Polk counties for more than 25 years.

George Kaiser is the CEO of Kaiser Francis Oil. He is ranked number 118 on the Forbes Rich List. He is majority owner of the Bank of Oklahoma and Cactus Drilling Company. He has been actively involved in the oil & gas industry in the Gulf Coast area for over forty years.

Bureau of Economic Geology at University of Texas

The JV undertook a collaborative three year regional geological study with the highly respected Bureau of Economic Geology at the University of Texas at Austin. The study involved the comprehensive analysis of over 2,500 wells, 2,700 miles of seismic data (2D and 3D) and hundreds of well cores. The conclusions of that study enabled the identification of key conditions believed to be required for the successful identification of high quality conventional oil & gas prospects in the Eagle Ford formation in East Texas.

Equipped with this proprietary knowledge, the JV was able to identify and map conventional oil & gas targets within the exploration areas. Additionally the JV has mapped other specific locations regionally.

The study will be kept unpublished by the Bureau of Economic Geology until authorisation for release is provided by Vision Gas Resources.

The purpose of the study was to identify a means of correctly identifying high quality pockets of good quality reservoir sands in the Eagle Ford formation. Such stratigraphic pockets have been discovered serendipitously in the area, but they have been difficult to
The study determined the geological conditions that would produce high quality reservoirs and also determined a means of identifying the high quality reservoirs by recognising their specific character on seismic data (amplitude anomalies).

The study was completed in 2014 and it is considered to be the most comprehensive study of its kind undertaken for the Eagle Ford formation.

**Regional Geology**

The petroleum system for conventional Eagle Ford reservoirs is conceptually simple and contained. Oil and gas are sourced within the ubiquitous shales of the formation itself. Conventional reservoirs consist of sands within the formation that provide sufficient porosity and permeability to allow for conventional oil production from vertical wells (no hydraulic fracturing). Sealing rock can consist of either overlying Eagle Ford shales or the regionally extensive Austin Chalk. The petroleum system is exceedingly robust. Source and seal are assured within the East Texas Basin. High quality sands exist extensively in the area as the original Double A Wells field makes clear (discovered in 1985 a few kilometres to the east of the VOBM#1 location). Exploring for conventional targets within the basin essentially consists of attempting to identify the location of high quality sands, which when found are proven to regularly contain oil & gas. The relevant stratigraphy for the East Texas Basin is provided below.

**Relevant (late Cretaceous to surface) stratigraphy of the East Texas Basin**

The Eagle Ford Group is of Late Cretaceous (Cenomanian-Turonian) age and it was deposited in a marine environment from what is now the southern tip of Texas eastward into Louisiana, Arkansas, Mississippi, Alabama and Florida over a period of about 10 million years starting about 100 million years ago.

The formation consists of a prograding shelf margin that extended into the Gulf of Mexico as sediment from the continent was deposited. The formation consists principally of low porosity/permeability rock that is generically referred to as the Eagle Ford shale although it consists of both shales and carbonates. The shales are regionally organic rich. The depositional environment consists of shelf-slope to distal turbidite fans.
Wave energy reduced further away from the coast and the more distal deposits tend to be tight shales. However on the shelf-slope there was a higher energy depositional environment (fast turbidite flows of sediment) which allowed for the deposition of coarse sands (good reservoirs) in certain geological contexts, creating stratigraphic petroleum traps. The US Geological Survey assessed the potential of undiscovered conventional reservoirs in the Eagle Ford formation and determined the play fairway essentially traces the continental shelf-slope at the time of the Cretaceous age as seen in the map below. The US Geological Survey identified the Baton Rouge area in Louisiana and the Polk and Tyler Counties in Texas as being the areas where discoveries have been found and where prospectivity is the most promising.

**Shelf Edge at Time of Cretaceous**

![Shelf Edge at Time of Cretaceous](Source US Geological Survey)
**Prospect Description**
Exploring for conventional reservoirs consists essentially of identifying the location of high quality productive reservoir sands surrounded by shales. This type of petroleum trap is referred to as a stratigraphic trap where the reservoir system is related to the depositional environment. In comparison structural traps are related to structural geology such as faults or folding. According to Schlumberger 40% of the oil found in mature hydrocarbon provinces is being found in stratigraphic traps (source: Exploring for Stratigraphic Traps, Jack Caldwell et al. Schlumberger Oilfield Review, 1997). Relative to exploring for structural trap analysis is often based extensively on seismic data analysis which seeks to identify changes in the rock type within a rock formation.

Generally the depositional environment of the Eagle Ford formation is laterally continuous, as seen in the image below. Of note, the height of the Eagle Ford formation ranges from circa 50 to 450 feet.

**Eagle Ford Outcrop, Example 1 (Lozier Canyon, Site of BP/Schlumberger Research)**

The Eagle Ford Formation also contains lateral discontinuity as shown in the following figure.
Pantheon’s targets consist of lateral discontinuities of high quality sands that have lateral distance of several kilometres.

Pantheon, Vision Gas Resources and the Bureau of Economic Geology at the University of Texas determined that the successful conventional reservoir targets around the Polk and Tyler counties have the following conditions for success:

i) The existence of a mini-basin (widths of several kilometres) on the shelf slope at the time of deposition that would have captured heavier coarser sands as sand carrying turbidity currents came down the shelf-edge to settle on the basin floor. The formation of mini-basins on the shelf slope during the Cretaceous age is known to have occurred due to the occurrence of salt movement in the underlying strata. This is a common geological occurrence where salt is present which is known to be the case under the Eagle Ford formation.

ii) The localisation of the mini-basin on a structural high at the time of deposition, which would have encouraged the deposit of coarse high quality sands.

iii) The identification of the stratigraphic presence of porous sands by seismic analysis. Effectively, seismic amplitude anomalies signal the high quality sands. This signal occurs between the Austin Chalk / Eagle Ford sands interface.

iv) The conditions that are known to exist systematically for conventional prospects in the Eagle Ford formation: the presence of source rock (Eagle Ford) and sealing rock (Austin Chalk).

**Analogue Field: Double A Wells**

The Double A Wells fields was discovered in 1985, and it has an expected ultimate recovery of circa 95 million boe, consisting of 21% oil (condensate) and 79% gas (source: *Facies Variability and Reservoir Quality in the Shelf-to-Slope Transition, Upper Cretaceous (Cenomanian) Woodbine Group, Northern Tyler and Southeastern Polk Counties, Texas, USA. William A. Ambrose et al. Bureau of Economic Geology, University of Texas, 2014*).

The Double A Wells field shares the same amplitude anomaly as the West Double A Prospect.
The sands from the Double A Wells field are from a shallow marine depositional environment (source: Facies Variability and Reservoir Quality in the Shelf-to-Slope Transition, Upper Cretaceous (Cenomanian) Woodbine Group, Northern Tyler and Southeastern Polk Counties, Texas, USA, William A. Ambrose et al, 2014). The sands have permeability of up to 1.3 darcies (excellent). The reservoir is overlain by 20 feet of shale and then the Austin Chalk. The reservoir has a sweet spot of circa 4 square miles (source: Double A Wells Field - A Prolific “Sleeper” in the Down dip Woodbine Trend in Texas, Fred L. Stricklin, 1998).

The reservoir is buried near 14,000 feet and is slightly overpressured (0.7 psi/feet gradient). The fine grained sandstone has particularly good porosity 23% and 1 darcy permeability (excellent). The reservoir sandstones are encased in organic rich source rocks/shales (source: Evolution and High Dissolution Porosity of Woodbine Sandstones in a Slope Submarine Fan, Double A Wells Field, Polk County, Texas – A Deep Water Gulf of Mexico Model Onshore, Fred L. Stricklin).

Double A Wells – Diagram

The well log and lithological schematic (below) shows the extraordinarily high permeability and porosity of the Double A Wells reservoir. The net pay in the field according to the well log is circa 17 feet.
We have reviewed the production profile of the Double A Wells field and conclude that it experienced exponential declines of circa 29% and that the gas oil ratio remains constant over the field’s productive life, indicating that the oil (condensate) and gas fluid remains in single gas phase in the reservoir over the productive life of the reservoir.

According to Pantheon, the Double A Wells field has been produced by circa 52 vertical wells indicating an expected ultimate recovery per well of circa 1.8 million boe.

According to a study by Robert J Bunge the sandstones within the Double A Wells mini basin are of a “highly variable stratigraphic character”. The study noted that generally in the Polk and Tyler counties within proven mini-basins, dry holes typically can be observed to offset wells that produce 10-16 bcfe (1.7-2.7 million boe). Moreover, the study indicated that for conventional Eagle Ford discoveries in the Polk and Tyler counties “production does not correlate to pay thickness, porosity or a porosity thickness multiple”, which is the result of stratified (non-homogenous) deposition and localised calcite diagenesis which can completely occlude porosity. Source: (Robert J. Bunge, “Woodbine Formation Sandstone Reservoir Prediction and Variability, Polk and Tyler Counties, Texas”, AAPG, 2007). We believe that the principle implication of the analysis of Robert J Bunge is that well productivity can be expected to be variable.

The image below shows the cumulative production of individual wells in red (in bcfe; 10 bcfe = 1.7 million boe). We note that there is significant variability in production, but that within the core area almost all the wells are excellent producers. Around the basin margins certain of the wells are excellent while others are significantly less productive.
Cumulative Production per Well in the Double A Wells Field Shows Variability

The nearby LP2 well which will be offset by the LP2 Offset Prospect well generated over $30 million of revenue from a high quality sand reservoir (the well has produced over 4bcf and 100,000b of condensate). Pantheon believes that the LP2 well was drilled through the pinch-out edge of a mini basin. The LP2 Offset well will be testing this hypothesis.

**Economic Analysis**

We have assumed that, if successful, the company’s Eagle Ford wells will have initial production rates of 1,208 boe/d, consisting of 250 b/d of oil (condensate) and 5.8 mmcf/d of gas. We have assumed that the wells decline exponentially at 29% p.a. We assume the gas oil ratio is 23 mcf/b or that the wells are 21% liquids – consistent with the Double A Wells field.

Our economic estimates are conservative relative to the most relevant analogue field, the original Double A Wells field, as we assume that each well produces 1.3 million boe (21% oil), compared to 1.8 million boe.

We have assumed the wells cost $5 million although that appears conservative in light of falling rig rates and the relative shallowness of the targets (circa 14,000 feet). We have assumed that lease operating costs amount to $78k/well/year, which is consistent with company guidance. We have also added an additional $0.50/boe to provide a margin of safety, which we believe reflects conservatism given that gas/condensate in the area can be expected to be produced efficiently due to the extensive existing infrastructure in the area.

Pantheon has $27 million of undeducted expenses for tax purposes. The US tax code allows companies to deduct drilling expenses over a 5 year period, although wells produce for much longer. This, coupled with the reality that growing oil & gas companies continuously invest more and more tends to mean that high growth oil & gas companies
in the USA typically do not pay income tax (35%). Commodity prices have further reduced the likelihood that income tax is relevant for most US oil companies. However, due to the extreme profitability of Pantheon’s wells in a success case, even in a low commodity price context, we have included income tax in our valuation.

We have modelled royalty rates of 32.5% for liquids and 29.6% for gas, reflecting the entirety of the company’s royalty burden.

We have assumed that the gas sells at a $0.20/mmbtu discount to benchmark (Henry Hub) US gas to reflect the local basis/transport differential, even though the gas would be energy rich (compared to pure methane) and could potentially sell for more. We have assumed the liquids produced are condensate, which is effectively light crude oil. We have applied a $5/b discount to our realised oil price to reflect the current condensate / WTI differential in East Texas (for circa 40-44° API condensate).

We have a long-term WTI crude oil price assumption of $60/b, which we escalate at 2% p.a. We have a long-term benchmark (Henry Hub) US natural gas price of $3.33/mcf, which we escalate at 2% p.a.

We have valued the wells using a 10% discount rate.

Success Case Well Economics Compared to Analogue Field

<table>
<thead>
<tr>
<th></th>
<th>BOE (kboe)</th>
<th>IP (boe/d)</th>
<th>Liquids/Total (%)</th>
<th>NPV10 ($US k)</th>
<th>IRR (%)</th>
<th>Payback (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Eagle Ford - Base Case</td>
<td>1,306</td>
<td>1,208</td>
<td>21%</td>
<td>12,802</td>
<td>216%</td>
<td>0.8</td>
</tr>
<tr>
<td>Conventional Eagle Ford - With Income Tax</td>
<td>1,306</td>
<td>1,208</td>
<td>21%</td>
<td>7,988</td>
<td>113%</td>
<td>1.3</td>
</tr>
<tr>
<td>Double A Wells (analogue field)</td>
<td>1,829</td>
<td>1,692</td>
<td>21%</td>
<td>20,146</td>
<td>447%</td>
<td>0.6</td>
</tr>
<tr>
<td>Double A Wells - With Income Tax</td>
<td>1,829</td>
<td>1,692</td>
<td>21%</td>
<td>12,761</td>
<td>206%</td>
<td>0.9</td>
</tr>
</tbody>
</table>

The following chart indicates how well economics can be expected to vary depending on both oil and gas prices. Due to the excellent reservoir characteristics of conventional Eagle Ford fields, when successfully discovered, and the existence nearby infrastructure, they are economically attractive even in very low commodity price environments.

Conventional Eagle Ford Wells (1.3 million boe EUR) – Commodity Price Sensitivity

Source Panmure Gordon
We believe that it is the US convention to value onshore oil & gas assets before income tax, reflecting that income tax is not likely to be paid on such assets assuming the company is reinvesting capital to grow. However, the exceptional profitability of conventional Eagle Ford wells, in a success case, is such that after-tax valuations may be appropriate. For the purposes of our valuation we have assumed that income taxes are paid by Pantheon - a conservative approach.

Our best estimate of the well economics applies to both the West Double A Wells prospect and the LP2 Offset prospect.

It is important to recognise that our per-well economics reflect the expected returns from an average well (assuming a successful discovery is made), we expect considerable variability around the average well result based on the experience of the Double A Wells field.

**Valuation and Economics of West Double A Wells Prospect**

In a success case, Pantheon estimates the West Double A Wells Prospect would produce a total of 58 million boe based on their volumetric assessment of the field. The company has assumed that to produce the 58 million boe 37 vertical wells will be required. We have assumed that an additional 7 wells will be required. The difference reflects that Pantheon has more directly applied the best estimates inferred from the analogue field (Double A Wells), whereas we have limited our initial production rate to 1,208 boe/d (including 250 b/d of liquids) to be conservative.

In our valuation we have assumed that the company pays income tax after it has utilised the $27 million of undeducted capital expenditure.

Our production model is provided in the following figure.

**West Double A Wells – Development Profile**

Our drilling programme assumes that multiple rigs are utilised to develop the field, as one rig drilling back to back would not be capable of drilling the required wells.

A summary of the cash flows in relation to the project are provided below.
Based on our commodity price and operating assumptions, we estimate that the project will breakeven on a cash flow basis in 2017. We assume that four wells are drilled into the field in 2016 (requiring a net capex of $12.5 million, inclusive of the well being drilled in 2015), after which we estimate the project can self-fund rapid growth.

Based on our assumptions we estimate that the net value to Pantheon of the West Double A Wells project in a success case would amount to $149.8 million.

**Valuation of LP2 Offset Prospect (being drilled by VOS#1 well)**

The success case valuation of LP-2 is essentially identical to that of West Double A Wells, except that we assume the LP-2 is developed with 3 fewer wells, reflecting that on a pre-drill basis it is estimated to be modestly smaller with an expected ultimate recovery of 53 million boe.

Our production model for LP2 Offset is provided below.

**LP2 Offset – Development Profile**

A summary of the cash flows in relation to the project are provided below.
Based on our assumptions we estimate that the net value to Pantheon of the LP2 Offset project in a success case would amount to $141.0 million.

**Pre-Drill Chance of Geological Success**

The prospects are being drilled into one of the best understood petroleum systems globally. The source rock (Eagle Ford shales) and capping rock (Austin Chalk) are known to be ubiquitous and reliable in the area.

We believe that the chance of success equates essentially to the probability that high quality sands are penetrated.

A nearby analogue field (Double A Wells) has provided evidence that locally high quality reservoir sands exist in mini basins. The LP2 well produced from high-quality sands, although the extent of sands has not been proven, but will be tested by the LP2 Offset Prospect well.

We believe that the identification of stratigraphic traps is inherently challenging, but appreciate that in the case of the identified prospects a geological model corroborates the seismic amplitude anomalies. We believe the amplitude anomalies are more robust because they occur almost directly below the Austin Chalk allowing for a clean interface. The Austin Chalk is laterally homogenous which would indicate that the anomalies from the Austin Chalk/Eagle Ford sands are indeed likely to be related to Eagle Ford sands.

We conclude that a 25% chance of geological success is reasonable for the West Double A Wells prospect, for which 3D seismic data is available.

*We have not reviewed the well logs or well data from the VOBM#1 and we have therefore not adjusted our geological chance of success higher to reflect that the well data was sufficiently encouraging for the company to complete and test the well.*

2D Seismic data is available for the LP2 Offset Prospect and the geological model for this prospect is supported by an offset well that penetrated high quality sands. Therefore we believe a 25% chance of success is also a reasonable estimate for this prospect.
**Austin Chalk Target**

We believe that the Austin Chalk is an attractive prospect in its own right and that if successful it would pave the way for a large scale drilling programme with compelling returns.

**Commercial background**

The commercial background and JV arrangement for the Austin Chalk prospect is identical to that of the Eagle Ford prospects.

The JV plans on drilling a horizontal lateral from the LP2 Offset well if that well does not make a commercial discovery in the Eagle Ford formation.

### Austin Chalk Prospect Inventory

<table>
<thead>
<tr>
<th>Current Drilling Status</th>
<th>County</th>
<th>Gross Prospective Scale (mmboe)</th>
<th>% Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Field</td>
<td>Tyler</td>
<td>43</td>
<td>19%</td>
</tr>
</tbody>
</table>

*Source: Pantheon*

**Regional Geology**


The Upper Cretaceous Austin Chalk forms a low-permeability, onshore Gulf of Mexico reservoir that produces oil and gas from major fractures oriented parallel to the underlying Lower Cretaceous shelf edge. Horizontal drilling links these fracture systems to create an interconnected network that drains the reservoir. Field and well locations along the trend are controlled by fracture networks. The fractures are generally tensile fractures related to gravity pulling the structure downdip. Salt structures often exacerbate this effect.

*Source Texas A&M University*
The idealised schematics above indicate that the faults would be not be readily discernible from seismic analysis because only the largest faults would involve large scale vertical displacement along a fault plane. The important micro fractures would not be be visible using conventional seismic techniques. Generally speaking, nearology (dilling in proven areas) is how the Austin Chalk has been developed.

The fracture systems tend to run parallel to the Cretaceous shoreline and faults are typically at right angles to that shoreline. Therefore moving up or downdip tends to change the gas oil ratio. Northerly wells tend to be more oily as a result. The faults are typically vertical and as a result typically vertical wells miss them, whereas horizontal wells systematically penetrate the faults, when they are present.

The Austin Chalk is a well-known onshore oil & gas play that extends across south-central Texas in southern Louisiana as shown in the chart below.
The Austin Chalk is composed principally of chalk (carbonate/fine grained limestone), but it also contains clays/marls which tend to reduce faulting when significantly present.

Matrix porosity is typically between 3% and 10% and generally decreases with depth. However, chalks are particularly vulnerable to diagenesis which has reduced the permeability to such an extent that conventional wells within the matrix (without fractures) do not produce at commercial rates. Permeability is typically near 0.1-0.5 mD, therefore production must rely on natural fractures. Fracture density and connectivity are highly variable. Fractures in the area have had widths of 0.1 to 4 mm.

Numerous trap types exist in the Austin Chalk play with many fields exhibiting a combination of trap types. Reservoirs that are in the updip region of the play are commonly sealed by normal fault traps with hydrocarbons accumulating in the downthrown side of faults.

**Austin Chalk (exposed by Ten Mile Creek)**

**Analogues**

Based on public data it is known that more than 80 wells have been drilled into the Austin Chalk just a few miles to the north of the LP2 Offset well location in a property owned by Anadarko and Ergon (private).

In 2009, Pantheon drilled a well just a few kilometres away in the Austin Chalk, the VRU#1. This well experienced a gas “kick” as a result of which the well was lost. Downhole gas pressure effectively more than offset the weight of the drilling mud and forced mud to evacuate the well as it was displaced by gas that was forcing its way up the wellbore. We believe that such a kick could not have occurred in the absence of natural fractures within the Austin Chalk.

**Conventional (no fracking), but hi-tech drilling**

Early drilling within the Austin Chalk focused on simple vertical wells that drained oil & gas from the local systems near the well. In the 1950s acid treatments increased the chalk's productivity. In the 1970s hydraulic fracturing of the reservoir was initiated, which enhanced and connected these fracture systems near vertical wells. A major advance for the Austin Chalk arrived in 1984, with the advent of horizontal drilling. Many of the tools and techniques for horizontal drilling were first developed to drill the Austin Chalk before being applied internationally. In the last 15 years the turning radius for horizontal wells has been reduced significantly. This has facilitated the re-entry of existing wells and will be used to side-track the LP2 Offset well into the Austin Chalk if the primary target of the
LP2O well is not commercial. Underbalanced or controlled drilling has also made an important contribution to drilling successful wells in the Austin Chalk from the late 1980s onwards. This technique allows for bottom-hole pressure to be reduced significantly while drilling operations are ongoing. This reduces the propensity for the drilling mud to flow into the highly permeable natural fractures which can reduce their natural permeability and well economics. The technique controls the downhole pressure so that it is neither too high (causing mud ingress into the fractures) or too low (allowing for a blowout) (source: Holifield Energy Company).

**Prospect Description**

Pantheon’s LP2O prospect is within the greater Brookeland Austin Chalk play area. However the company’s West Double A Wells prospect is further to the west and outside of the core Brookeland Austin Chalk play area.

Pantheon’s best estimate of the recoverable resources from the Austin Chalk prospect is 43 million boe, in a success case, of which 19% is expected to be oil (condensate). This potential recovery factor is premised on Pantheon’s estimate that it has 42 well locations on the proven area of the Austin Chalk play and that based on proximal wells each well can be expected to produce 1.02 million boe (19% oil/condensate)

The Brookeland field is known to exist in Tyler, Jasper, Newton, Sabine and San Augustine counties. It is not known to extend into Polk County.

The field is productive in the lower Ector member of the Austin Chalk, because it is the most densely fractured member. Within the Brookeland field this member averages 25m and is characterised by low average matrix porosity (3%) and permeability (0.1 mD), with reservoir porosity and permeability created by fracturing. An ash bed lying above the Ector acts as seal (source: The Austin Chalk of Brookeland Field, David J. Hooks et al. 1994).

**Economic Analysis**

We have estimated that the initial 30 and 90 day average production rates for Pantheon’s Austin Chalk wells are 2,267 boe/d and 1,994 boe/d, respectively, with 19% of production being oil (condensate). We estimate that the ultimate recovery per well, on average, is 1.0 million boe, with 19% of that being oil (condensate). We expect significant variability from one well to the next due to the variable nature of natural fractures.
We expect steep declines from a high initial production rate, which is an inherent part of producing from fractured reservoirs, which favours a high NPV and early payout.

We expect it will cost an extra $1.0 million to drill a horizontal lateral into the targeted horizon, and we assume well costs will amount to $6.0 million, which is based on the high end of the company’s internal estimates.

We have assumed that lease operating costs amount to $78k/well/year, which is consistent with company guidance. We have also added an additional $0.50/boe to provide a margin of safety, which we believe reflects conservatism given that the production of gas/condensate in the area can be expected to be efficient/straightforward.

Pantheon has $27 million of undeducted expenses for tax purposes. The US tax code allows companies to deduct drilling expenses over a 5 year period, although wells produce for much longer. This, coupled with the reality that growing oil & gas companies continuously invest more and more each year tends to mean that high growth oil & gas companies in the USA typically do not pay income tax (35%). Commodity prices have further reduced the likelihood that income tax is relevant for most US oil companies. However, due to the extreme profitability of Pantheon’s wells, even in the current low commodity price context we have included income tax in our valuation.

We have modelled royalty rates of 32.5% for liquids and 29.6% for gas, reflecting the entirety of the company’s royalty burden.

We have assumed that the gas sells at $0.20/mcf discount to benchmark gas prices. We have assumed the liquids produced are condensate, which is marketed like a light crude oil. We have applied a $5/b discount to our realised oil price to reflect the current condensate / WTI differential in East Texas (for circa 40-44.9° API condensate).

We have a long-term WTI crude oil price assumption of $60/bbl, which we escalate at 2% p.a. We have a long-term benchmark (Henry Hub) US natural gas price of $3.33/mcf (starting in the current half), which we escalate at 2% p.a.

We have valued the wells using a 10% discount rate.
The chart below indicates how well economics can be expected to vary depending on both oil and gas prices. Due to the excellent reservoir characteristics of conventional Eagle Ford fields, when successfully discovered, and the existence of nearby infrastructure, they are economically attractive even in very low commodity price environments.

### Success Case Well Economics

<table>
<thead>
<tr>
<th></th>
<th>BOE (kboe)</th>
<th>IP (boe/d)</th>
<th>Liquids/Total (%)</th>
<th>NPV10 ($US k)</th>
<th>IRR (%)</th>
<th>Payback (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austin Chalk – Base Case</td>
<td>1,000</td>
<td>2,267</td>
<td>19%</td>
<td>7,628</td>
<td>181%</td>
<td>0.8</td>
</tr>
<tr>
<td>Austin Chalk – With Income Tax</td>
<td>1,000</td>
<td>2,267</td>
<td>19%</td>
<td>4,551</td>
<td>74%</td>
<td>1.3</td>
</tr>
</tbody>
</table>

*Source: Panmure Gordon*

### Austin Chalk Wells (1.0 million boe) – Commodity Price Sensitivity

In a success case, Pantheon estimates its Austin Chalk resource would produce a total of 43 million boe based on their assessment of recoveries per well (1.02 million boe consisting of 190,000 barrels of oil/condensate and 5 bcf of gas) and the number of well locations (42) within their landholdings. Our model is consistent with these assumptions.

In our valuation we have assumed that the company pays income tax after it has utilised the $27 million of undeducted capital expenditure.

Our indicative production model is provided in the following chart.
Our drilling programme assumes that multiple rigs are utilised to develop the field, as one rig drilling back to back would not be capable of drilling the required wells.

A summary of the cash flows in relation to the project are provided below.

The chart above indicates that due to the rapid delivery of oil & gas from the fracture systems in the Austin Chalk wells, a modest number of wells would set the company off on a rapid self-funding growth trajectory. Based on our assumptions the wells will be economically attractive at a low-commodity price environment, however, a low commodity price environment would affect the rate of growth.

Based on our assumptions we estimate that the net value to Pantheon of the Austin Chalk prospect in a success case would amount to $85.5 million.
**Geological and Economic Assessment ► Austin Chalk Target**

**Chance of Geological Success**

We estimate that the LP2 Offset well has a 31% chance being as economic within the Austin Chalk as we have modelled in our valuation, which is what we have used as our “geological chance of success”, knowing that for this well the real question relates to the productivity of the fracture network (how commercial will it be?) vs. whether or not the well will penetrate a fracture network.

We believe this is conservative given we estimate that there is a circa 90% chance that the well will penetrate a natural fracture network (based on a nearby well control, the location of the well within the productive area of the Brookeland field, and because the nearby VRU#1 well experienced a kick). Our geological chance of success in this case effectively overlaps somewhat with some commercial risk and reflects an assumption relating to whether a fracture network, if present, can deliver 1.0 million boe/well.

<table>
<thead>
<tr>
<th>Geological Chance of Success</th>
<th>Assumed Probability</th>
<th>Probability of Success</th>
</tr>
</thead>
<tbody>
<tr>
<td>Probability of gas/oil in petroleum system</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Probability of sealing rock</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Probability of encountering natural fractures</td>
<td>90%</td>
<td>90%</td>
</tr>
<tr>
<td>Probability natural fractures will be commercial</td>
<td>40%</td>
<td>40%</td>
</tr>
<tr>
<td>Probability of losing well (lost circulation or kick)</td>
<td>15%</td>
<td>85%</td>
</tr>
<tr>
<td><strong>Geological chance of success</strong></td>
<td></td>
<td><strong>31%</strong></td>
</tr>
</tbody>
</table>

*Source* Panmure Gordon