ABN 42 112 256 649
www.solimarenergy.com.au

21 January 2013

RELEASE TO ASX

Paloma Deep Testing Confirms Unconventional Resource Potential

NOT FOR DISTRIBUTION TO UNITED STATES NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES

Solimar Energy Limited (ASX:SGY, TSXV:SXS) ("Solimar" or the "Company") is please to provide the attached release from the Paloma project operator, Neon Energy Limited (ASX:NEN).

For further information contact: Will Satterfield - Chief Executive Officer

Phone 1-805-643-4100 and website: www.solimarenergy.com.au

Reader Advisory: Potential resource estimates and forward-looking statements

This news release contains forward-looking information relating to adding to reserves and resource estimates, planned development and exploration activities on the properties in which the Company has interests, and other statements that are not historical facts. Such forward-looking information is subject to important risks, uncertainties and assumptions. The results or events predicated in this forward-looking information may differ materially from actual results or events. As a result, you are cautioned not to place undue reliance on this forward-looking information.

Forward-looking information is based on certain factors and assumptions regarding, among other things, the impact of increasing competition; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and the ability of the Company to successfully market its oil and natural gas products, and other similar matters. While the Company considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

Forward looking-information is subject to certain factors, including risks and uncertainties that could cause actual results to differ materially from what is currently expected. These factors include risks associated with instability of the economic environments in which the Company operates or owns interests, oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources, reliance on key personnel, regulatory risks and delays, including risks relating to the acquisition of necessary licenses and permits, environmental risks and insurance risks.

The estimates of resources in this news release constitute forward-looking information which is subject to certain risks and uncertainties, including those associated with the drilling and completion of future wells, limited available geological data and uncertainties regarding the actual production characteristics of, and recovery efficiencies associated with, the reservoirs, all of which are being assumed. As estimates, there is no guarantee that the estimated reserves or resources will be recovered or produced. Actual reserves and resources may be greater than or less than the estimates provided in this presentation.

You should not place undue importance on forward-looking information and should not rely upon this information as of any other date. While the Company may elect to, the Company is under no obligation and does not undertake to update this information at any particular time, except as required by law.

NEON ENERGY LIMITED

ANNOUNCEMENT TO THE AUSTRALIAN SECURITIES EXCHANGE: 21 January, 2013

Paloma Deep Testing Confirms Unconventional Resource Potential

Highlights

- **Potential for commercialisation of Lower Stevens via "unconventional" development**
- **Lower Antelope Shale offers potential for 500 Bopd to 800 Bopd per well.**
- **Well operations being suspended pending completion of reservoir modelling**

Neon Energy Limited (ASX: NEN) is pleased to provide the following update regarding ongoing production testing operations at the Company's Paloma Deep oil and gas discovery.

Testing of the Lower Stevens "B" sand in the Paloma Deep-2 well is nearly complete, with recovery rates of up to 8 barrels of oil per day and 20 thousand cubic feet of gas per day. This is lower than was achieved at the Paloma Deep-1 well which saw a maximum flow rate of 226 barrels of oil/condensate per day and nearly 2 million cubic feet of gas per day. The reason for the lower flow rate is believed to be mainly due to lower reservoir permeability, although the nature of the well completion and a sub-optimal fracture stimulation are also possible contributing factors.

Downhole gauges are currently recording shut in build-up pressure data. The gauges will be retrieved in approximately one week, after which diagnostics for reservoir parameters will be incorporated into simulation models of potential development scenarios.

Based on the data recovered from testing operations and the conventional core recovered from the well, the Lower Stevens interval is considered a viable candidate for commercial development using so called "unconventional" development techniques that employ horizontal well completions with multi-stage fracture stimulation, similar to what is already envisaged for the development of the Lower Antelope and the Fruitvale intervals. Preliminary modelling of the Lower Antelope suggests that initial production rates of 500 to 800 Bopd per well could be achieved.

Neon Energy Managing Director Ken Charsinsky commented, "*Although the Lower Stevens test at Paloma Deep-2 did not replicate flow rates encountered at Paloma Deep-1, we are encouraged by the potential for commercialisation of the unconventional resource of the Lower Stevens in tandem with development of the Antelope Shale."*

"We have now confirmed the presence of a significant resource which provides the basis to substantially grow our business in California. We have commenced discussions with prospective partners and service providers with a view to building a team with the right expertise to undertake a development of this type," added Mr Charsinsky.

Production from unconventional reservoirs in North America has quadrupled to more than 2 MMBopd between 2010 and 2012, and is expected to double again by 2016[(1)]. The geological interval that includes the Lower Antelope, the Lower Stevens and the Fruitvale shale is collectively known as the Monterey Formation. The Monterey play of southern California has been recently assessed by the U.S. Department of Energy[(2)] to contain 64% of the total shale oil resources estimated to exist in the entire Lower 48 contiguous US States. The study attributes 15.4 billion barrels of “technically recoverable” tight oil to the Monterey, and compares it to the next largest shale oil play of the Bakken and Eagle Ford, which are estimated to respectively hold approximately 5.4 billion barrels and 2.5 billion barrels of “technically recoverable” tight oil resources. While this study is regional in nature without specific application to the Paloma Field, it does indicate that the stratigraphic interval being developed by Neon is part of a play with enormous potential.

The Company previously released a Contingent Resource estimate for Paloma which is in the process of being revised through the evaluation of new data from Paloma Deep-2 and the incorporation of alternate development scenarios. While the resource potential of the Lower Antelope shale is unlikely to change significantly, the unrisked potential of the Lower Stevens “B” may change in line with the more “unconventional” nature of the reservoir; although any decrease due to reduced recovery rates might be offset by an increased in-place resource with greater areal extent.

Further potential remains in the shallow Paloma Sand secondary targets, which have yet to be tested in either the Paloma Deep-1 or Paloma Deep-2 wells. If these shallow zones were to be tested now it would compromise the Company’s ability to re-enter the wells to collect further data from the deeper zones, and therefore until all analysis is complete all well operations will be suspended.

Neon is excited about the Paloma development opportunity and has commenced discussions with specialists and prospective partners who have the necessary expertise to undertake such a project. The attached Paloma Project Overview provides a more detailed technical update on the Paloma project.

Neon holds an 85% working interest in the three Paloma wells, with partner Solimar Energy (ASX: SGY) holding the remaining 15%.

Enquiries:

Managing Director:	Ken Charsinsky
Chief Financial Officer:	Ben Newton
Telephone:	08 94811176
Website:	www.neonenergy.com

(1) http://www.energybulletin.net/stories/2012-12-19/future-production-from-u-s-shale-or-tight-oil

(2) US Energy Information Administration/Annual Energy Outlook 2012.

1. EXECUTIVE SUMMARY

This report provides a technical summary of the Paloma Deep project further to the Paloma Project Overview released to the ASX on 21 June 2012.

Neon Energy has drilled and tested three wells at its Paloma project, onshore southern California. The Paloma leases cover 2,847 acres over the Paloma field, a mature oil field that has produced over 60 million barrels of oil and 430 billion cubic feet of gas to date. Neon recognised that 3D seismic technology and modern drilling/completion methods presented an opportunity to discover hydrocarbons in up to eight target horizons within the Monterey Formation, both conventional and unconventional in nature. The Monterey Formation represents an emerging petroleum play that is potentially the largest unconventional resource in North America. While conventional reservoirs within the Monterey Formation have been producing in California for many years, only relatively recently has the potential for large scale unconventional resources been recognised, generating significant industry interest.

Neon's drilling and testing operations at the Paloma Deep-1 and Paloma Deep-2 wells have confirmed hydrocarbon pay in up to eight separate reservoir formations, and have confirmed potential for commercial development of unconventional resources hosted within the Lower Antelope Shale, Fruitvale Shale and Lower Stevens Sand. Unconventional resources in the case of the Monterey comprise oil shales and low permeability, "tight" sandstone reservoirs, both of which can be commercialised via the drilling of high angle or horizontal wells combined with fracture stimulation (fraccing) and other stimulation methods.

Production testing operations in both wells recovered oil/condensate and gas at low but stable rates, consistent with low permeability reservoirs in unstimulated, vertical wells. A notable exception is the Lower Stevens "B" Sand in Paloma Deep-1, which flowed oil at up to 226 barrels of oil per day before the test ceased prematurely. This result provided encouragement for possible commercial development of the Lower Stevens "B" using conventional development methods, however testing of the same zone at Paloma Deep-2 suggests the reservoir may actually be unconventional in nature, and therefore will need to be developed accordingly. The shallower and conventional Paloma Sands remain to be tested in both wells, and may contain hydrocarbon pay that was bypassed during prior development. For operational reasons testing of the Paloma Sands has been postponed until the forward programme for the project as a whole is determined.

The discoveries at Paloma represent a significant in-place resource of oil and associated gas, likely of the order of 200 to 300 MMBOE (million barrels of oil equivalent). The previously quoted Contingent Resource estimates provided by Neon are under review subject to final data acquisition and analysis, and may be subject to some change. However Neon maintains its belief that potential exists for commercial development, and that the size of the potential resource is material to the Company. The challenge is to determine a development strategy that will maximise recovery of the hydrocarbons while minimising the unit cost of production, such that commercial development can begin. Neon has commenced discussions with a number of companies who have expressed interest in the Paloma project, with a view to expanding the joint venture to bring in appropriate expertise and funding in order to progress development of the asset to the next stage.

2. INTRODUCTION

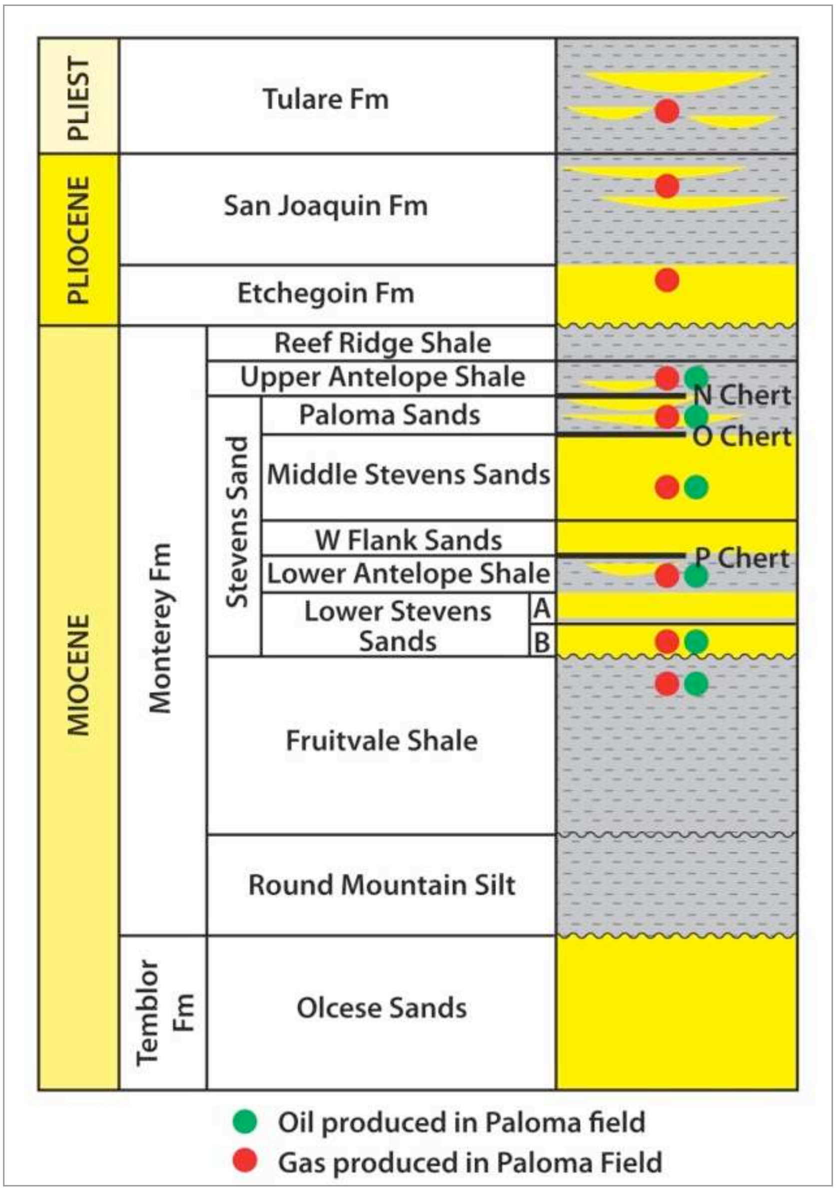
Testing of the Lower Antelope Shale in the Paloma Deep-1 well (PD-1) has now been completed, and preliminary modelling indicates that the unconventional resource present in this formation could be commercially developed. These models predict initial flow rates in the range of 500 to 800 barrels of oil per day (Bopd) based on horizontal wells coupled with multi-staged fracture stimulation. Production from additional zones such as the Lower Stevens or the shallow Paloma Sands could substantially augment these rates.

At Paloma Deep-2 (PD-2) production testing of three zones (Lower Stevens "B", Fruitvale Shale and the McDonald sand) has now been completed. Testing of the Lower Stevens "B" did not replicate the encouraging oil and gas flow rates encountered at PD-1, largely due to the low effective permeability of the reservoir completion at the PD-2 location. If it is assumed that the Lower Stevens flow rates from PD-2 are more representative of the field as a whole, then a conventional development is unlikely to be economic. Preliminary indications are that the Lower Stevens could be commercially developed with horizontal wells stimulated with multi-stage fracture stimulation, similar to what is envisaged for the Fruitvale and Lower Antelope zones. This style of development is commonly referred to as being "unconventional". More detailed simulation modelling is required in order to evaluate potential flow rates for such a development, and that work will commence once final pressure data is retrieved within the next week.

"Unconventional" development of oil reserves has become increasingly commonplace in North America, where production from unconventional reservoirs has quadrupled to more than 2 MMbopd between 2010 and 2012, and is expected to double again by 2016(1). Development of Paloma Deep resources using "unconventional" development techniques should not be regarded as out of the ordinary, and Neon has already begun discussions with specialists and prospective partners who have the necessary expertise and capital to undertake such a project.

The geological interval that includes the Lower Antelope, Stevens and the Fruitvale shale is collectively known as the Monterey Formation. The Monterey play of southern California has been recently assessed by the U.S. Department of Energy(2) to contain 64% of the total shale oil resources estimated to exist in the entire Lower 48 contiguous US States. The study attributes 15.4 billion barrels of "technically recoverable" tight oil resources to the Monterey, and compares it to the next largest shale oil plays of the Bakken and Eagle Ford, which are estimated to respectively hold approximately 5.4 billion barrels and 2.5 billion barrels of "technically recoverable" tight oil resources. While this study is regional in nature without specific application to the Paloma Field, it does indicate that the stratigraphic interval being developed by Neon represents a petroleum play with enormous potential.

While testing results have confirmed the potential for Fruitvale and Lower Antelope unconventional development, indications are that the Lower Stevens is a suitable candidate for unconventional development as well, meaning that rather than having a mixed development scenario we actually have a proven hydrocarbon resource suitable for a fully unconventional development. This will require specialised techniques and expertise to commercialise, and Neon is therefore in discussions with interested parties with the necessary capital and expertise with a view to expanding the joint venture in order to progress commercialisation of the asset.



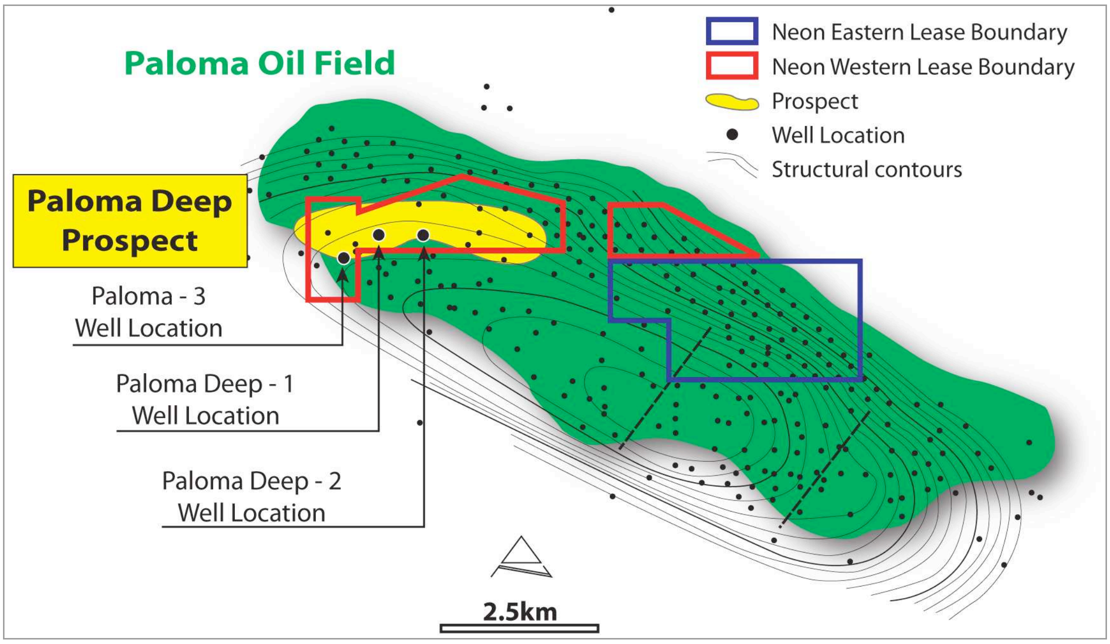
Paloma Area Statigraphy

(1) http://www.energybulletin.net/stories/2012-12-19/future-production-from-u-s-shale-or-tight-oil

(2) US Energy Information Administration/Annual Energy Outlook 2012.

3. BACKGROUND INFORMATION

The Paloma field is located in the southern San Joaquin Basin and was originally discovered in 1934. Production commenced shortly thereafter, principally from the shallow Paloma Sandstone Formation. Initial development consisted of 150 oil wells and 45 gas wells, with a secondary phase in 1973 consisting of 23 additional wells targeting the Lower Stevens Formation to the southeast. Having produced in excess of 60 million barrels of oil and 432 billion cubic feet of gas the field ceased producing at significant rates some 25 years ago and today lies essentially abandoned, with only 80 bopd being produced from the Lower Stevens Formation in the southeastern portion of the field. More recently the Upper Antelope Shale is being produced by a single well in the eastern part of the field.



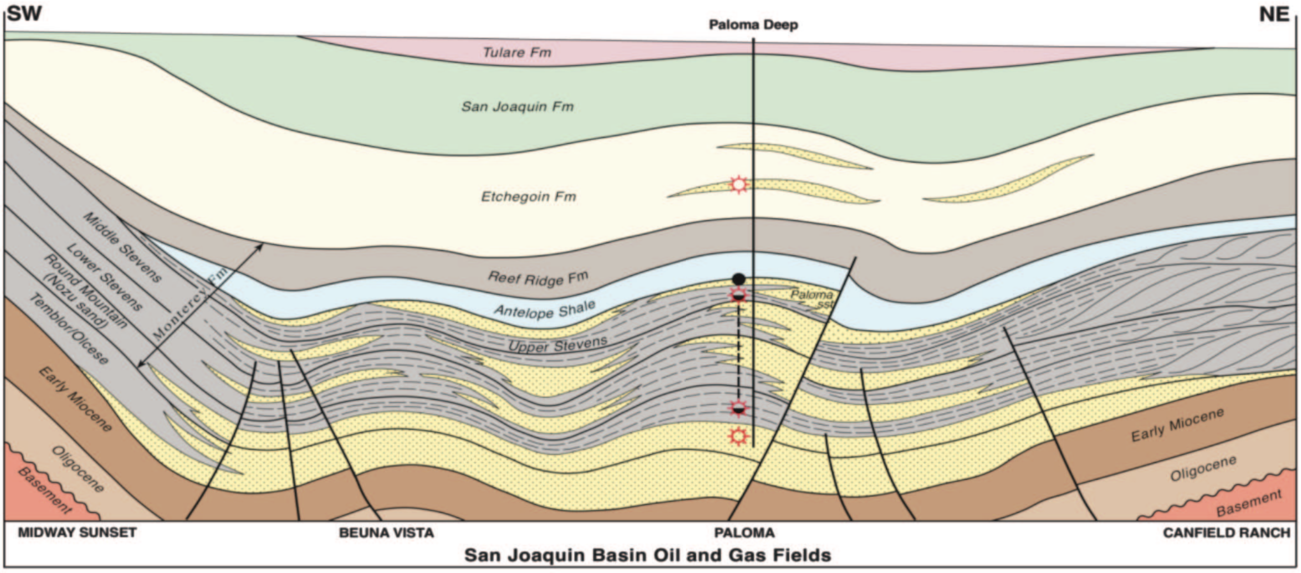
Paloma area schematic map showing location of wells and leases

Neon holds an 85% working interest in the original (western) leases, and a 75% working interest in the new (eastern) leases, with Solimar Energy holding the balance of interest.

3.1 Paloma Deep Play Concept

The opportunity at Paloma is presented by a combination of 3D seismic analysis, modern drilling/completion technologies and the recent recognition of the Monterey formation as a significant unconventional resource. The Paloma Deep play concept was to test numerous prospective zones, both conventional and unconventional, including the Stevens Sands, Antelope Shale and Fruitvale Shale; members of the Monterey Formation. These zones have not been previously produced at the northwestern end of the field, despite having been proven productive to the southeast and elsewhere in the San Joaquin Basin.

Analysis of the 3D seismic amplitude response in the Stevens Sands suggested the potential for development of a permeable reservoir at the north-western end of the field. While drilling, the Paloma Deep-1 well would also test for bypassed pay zones in the previously produced shallow zones of the Etchegoin and San Joaquin, and Paloma Sand formations. A deep gas prospect in the Round Mountain siltstones, supported by a seismic anomaly, was also originally an objective and remains a target for future exploration.



Schematic cross-section showing Paloma Deep play concept

4. PALOMA DEEP-1

The vertical PD-1 well was drilled in late 2011 with a TD of 13,320 feet. Analysis of wireline logging data confirmed the presence of oil and/or gas/condensate in eight zones including three unconventional oil shale zones. In aggregate these eight zones represent approximately 1,000 net feet of potential hydrocarbon pay. An extensive production testing programme was completed, with further testing of shallow targets remaining to be undertaken.

The most notable zone of interest was encountered in the Lower Stevens "B" sand, within which a gross column of 230 feet of continuous potential hydrocarbon pay is interpreted with a reservoir net to gross ratio of 81%. This pay zone flowed oil and gas on test at a maximum unassisted rate of 226 Bopd and 2 MMcfd gas, before the test ceased abruptly due to mechanical issues. Subsequent testing of the zone was compromised, believed due to structural failure of the reservoir formation as a result of geomechanical stresses exceeding the formation strength.

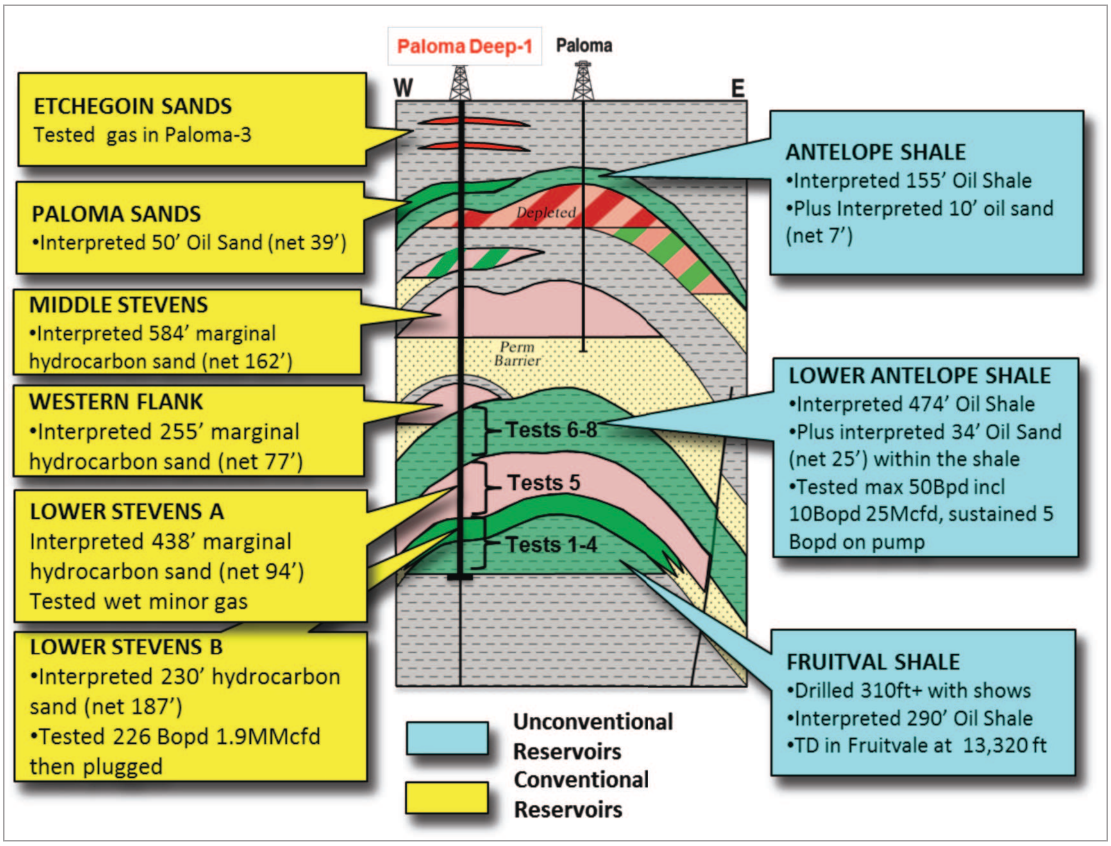


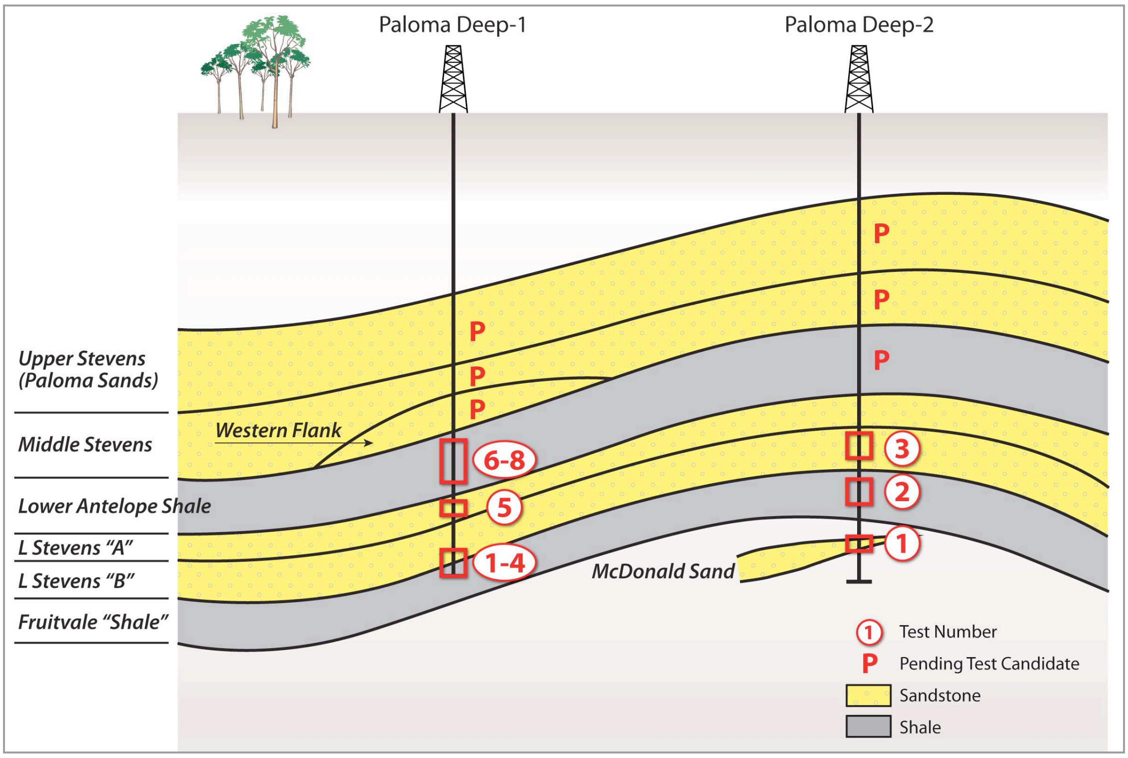
Figure: Schematic showing the log and test results in target reservoirs of the Paloma Deep-1 well

The Lower Antelope Shale is characterised by a favourable combination of being a naturally fractured siliceous shale (chert) and a mature source rock that is presently generating oil within the Paloma area. The 508 foot section encountered in the PD-1 well has proven to be a prime candidate for unconventional oil production. As a resource play extending across the entire 2,847 gross acres of Neon's leases, the Lower Antelope Shale is potentially a very significant resource. The most recent production test added perforations across a sandy section towards the top of the Lower Antelope zone, achieving initial rates of 50 barrels of fluid per day, both unassisted and assisted by jet pump. This declined to a steady rate of between 15 and 22 barrels of fluid per day with a 30% to 40% oil cut. This important test demonstrates that a potentially commercial resource is present, most likely developed with horizontal wells combined with multi-stage fracture stimulation.

The Fruitvale Shale also exhibits characteristics of a producing oil shale and is interpreted to be approximately 1,300 feet thick at the well location, although PD-1 penetrated only 310 feet of the formation upon reaching Total Depth. Two production tests of the Fruitvale Formation recovered oil and gas although it is thought that some of this production may have derived from the Lower Stevens "B" sand, bypassing leaking swellable external packers.

4.1 Paloma Deep-1 Test Summary

Five zones of interest have been tested, via eight production tests. In order to obtain commercial production rates from an unconventional (low permeability) reservoir, effective connection via a natural or man-made fracture system is necessary. Determination of reservoir characteristics and the potential efficacy of various well stimulation techniques in these oil reservoirs requires the integration of wireline log data with pressure transient data obtained during long-term production tests.



Paloma Deep Testing Intervals

Testing of the Fruitvale and Lower Stevens formations has confirmed the presence of producible gas and light oil/condensate. The individual tests are summarised as follows:

Test 1, Fruitvale Shale: Flowed to the surface unassisted at a maximum rate of 226 bpd of oil/condensate (oil gravity 40°API) and 1.9 MMcfd gas. It is believed that the flow is primarily attributable to the Lower Stevens sandstone, bypassing a defective "swellable packer". After flowing for 23 hours the flow ceased abruptly due to the testing tools becoming plugged with debris.

Test 2, Lower Stevens Sand: Stimulated with nitrogen and produced a maximum flow at surface of 343 Mcfd (thousand cubic feet per day) gas. The tool was subsequently found to be plugged with sand fill found below the test tool. It is believed that the reservoir formation collapsed around the outside of the casing due to geomechanical stresses that exceeded the formation strength of the local sandstone facies. This resulted in a production barrier in the annulus of the borehole (as in the test tool), inhibiting flow. This was confirmed by similar results in Test-3.

Test 3, Lower Stevens Sand: Additional perforations were added in the Lower Stevens interval, however only similar results to Test-2 were achieved. Test performance believed to be severely affected by the compromised “swellable packer” completion and sanding issues.

Test 4, Lower Stevens and Fruitvale Formations: Testing of the two zones combined resulted in similar gas flow rates and oil recoveries to Test-2 and Test-3.

Test 5, Lower Stevens “A” Sand: Produced water into the well bore with only a small amount of gas. This zone is therefore deemed to be non-commercial.

Test 6, Lower Antelope Shale: This test was conducted in the lower two thirds of the Lower Antelope Shale, in naturally fractured shale and chert beds. It was a highly successful test in that it established that oil can be swabbed (pumped) out of the Antelope Shale prior to stimulation, and improvements in flow rate were recorded after an acid wash which was performed to remove plugging solids from reservoir pores at the wellbore interface.

Test 7, Lower Antelope Shale: Added perforations to the previous test zone and a larger acid stimulation job was conducted. A jet pump was installed to produce back the acid-load volumes and to conduct a long-term production test. Although the well did not fully “clean up”, oil production from the zone was achieved, with pump-assisted rates ranging from 20 to 200 barrels of fluid per day and oil percentages ranging from 10% to 20%. While these rates on their own do not at first appear significant, the potential is good for commercial production via stimulated high angle or horizontal wells (see Test 8). Oil gravity was measured at 28°API to 30°API and it is anticipated that with continued pumping the test would have cleaned up further, with an associated increase in oil cut. Neon is using the test data from this zone to update its estimate of the magnitude of the potential resource and the optimal completion strategy.

Test 8, Lower Antelope Shale: Added perforations across a sandy section towards the top of the Lower Antelope zone. Initial rates of 50 barrels of fluid per day, both unassisted and assisted by a jet pump, declined to a steady rate of between 15 and 22 barrels of fluid per day with a 30% to 40% oil cut. This test demonstrated that a potentially commercial resource is present. Initial modelling results indicate that flow rates of 500 to 800 bopd from horizontal multi-stage fracced wells could be attained.

Future testing targets include the shallow Paloma Sands and Upper Antelope Shale, however impediments to testing deeper reservoirs could be created by perforating and testing shallower targets now. Therefore these zones will be tested only after a comprehensive forward programme for the entire project is determined.

5. PALOMA DEEP-2

The PD-2 well was conceived as an appraisal well to confirm the areal extent and flow potential of the Lower Stevens and Fruitvale formations. Certain changes from the PD-1 well design were made as an attempt to alleviate problems encountered in the PD-1. For example, a standard cemented liner completion was adopted in order to mitigate the risk of leakage between zones due to non sealing swell as is believed to have occurred in the PD-1 well. Further, a larger well bore enabled more thorough evaluation of the zones of interest as well as facilitating the gathering of data such as a conventional core through the zones of interest. The targeted well location was structurally up-dip of PD-1 and was chosen based upon a zone of high seismic amplitude at the Lower Stevens "B" level, which was expected to correlate with favourable reservoir parameters.

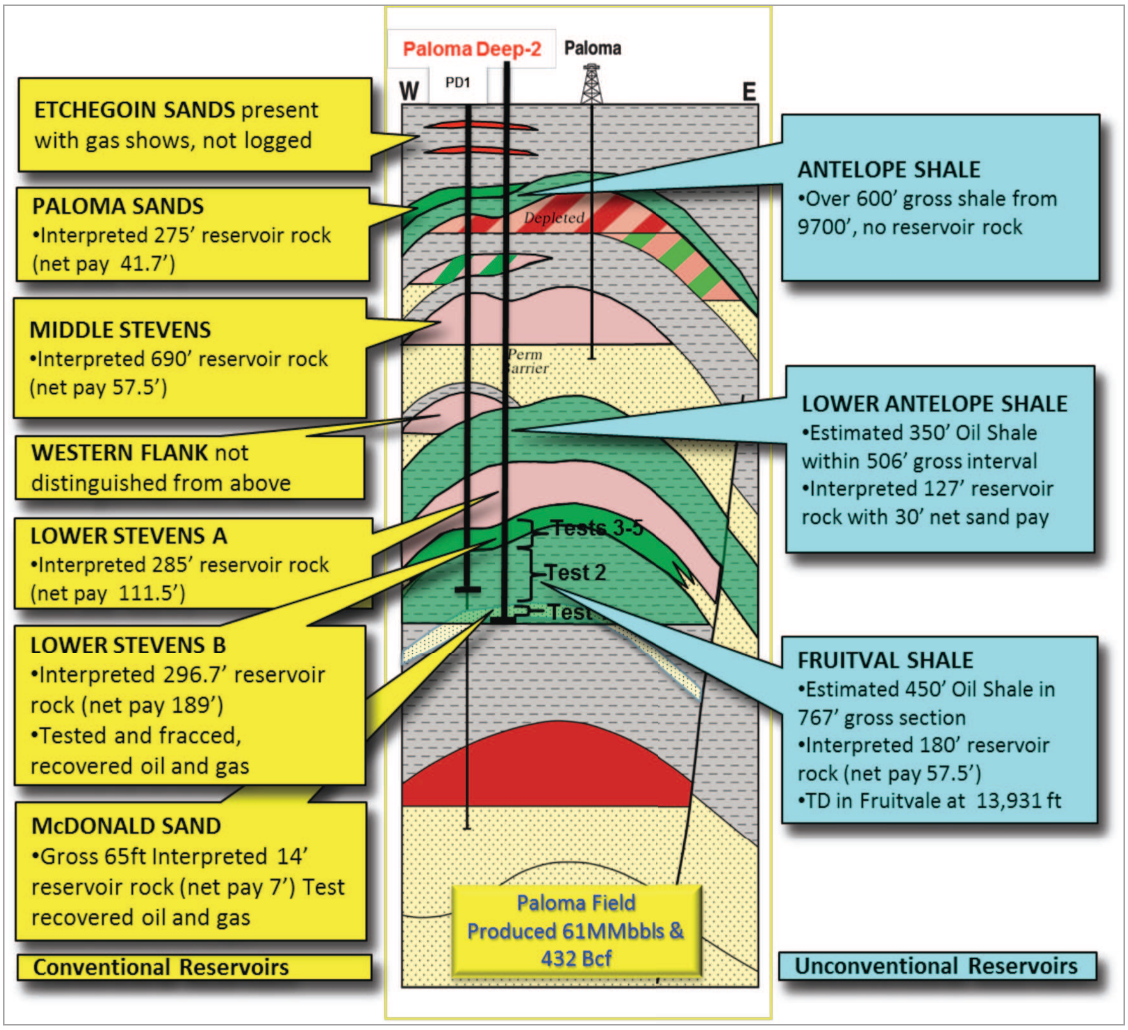


Figure: Schematic showing the log and test results in target reservoirs of the Paloma Deep-2 well

The well reached a TD of 13,931 ft in July 2012, in the Fruitvale Shale. Cores were acquired in the Lower Antelope, Lower Stevens "B" and Fruitvale Shale and a full suite of logs including an image log were recorded over these intervals. The intersection of the Lower Stevens "B" was structurally 50 ft high to the PD-1, as prognosed. As the well approached the planned TD, gas levels increased and a decision was made to deepen the well, penetrating the McDonald Sand at 13,812 ft with associated strong gas shows at surface. After regaining control of the well by increasing the mud weight, it was subsequently drilled to a final TD of 13,931 ft at which point logging operations began.

Close to 500 ft of net pay is interpreted from logs in the conventional reservoirs between the Paloma Sands and the McDonald Sand, with additional significant potential pay in the unconventional Antelope and Fruitvale Shales. Testing of the McDonald Sand, Fruitvale Shale and Lower Stevens “B” sand have all resulted in low flow rates of oil and gas, typical of low permeability reservoirs. Testing of the Lower Stevens “B” did not achieve a flow rate comparable to that seen in PD-1, believed to be primarily the result of two main factors: 1) the reservoir is characterised by lower permeability than that encountered in PD-1, and 2) the conventional cemented completion limits the amount of the reservoir exposed to the wellbore. Localised fracture stimulation was completed in the Lower Stevens “B” prior to testing, but it may not have effectively fractured the formation due to mechanical issues.

5.1 Paloma Deep-2 Test Summary

Three zones of interest have been production tested, with the individual tests summarised as follows:

Test 1, McDonald Sand: Testing confirmed the presence of light oil (36°API) and associated gas in this low permeability, overpressured sandstone. The McDonald sand is thought to be a continuous sand body within the Fruitvale Shale Member.

Test 2, Fruitvale Shale: Produced 36° API oil and associated gas from the 545 ft section tested, however the (unstimulated) flow rates were very low.

Test 3, Lower Stevens “B” Sand: A localised fracture stimulation was performed prior to testing, and the “frac” is thought to have been compromised resulting in a limited fracture network. However once the well was put on flow with a jet pump, a flow of 41° API oil at up to 7.7 bopd (within a total fluid rate of 15-23 bpd) was accompanied by a steady but low gas flow of around 20 Mcfd. In total 74 barrels of oil were recovered. Setting aside the potential impact of mechanical issues the low flow rate is considered to be due primarily to low permeability of the reservoir section. For the time being the PD-2 data are being considered to be more reflective of the field as a whole than the PD-1 data as this provides a conservative base case upon which an unconventional development scenario can be considered.

6. PALOMA-3

The shallow, low cost Paloma-3 well was drilled during May 2012, to a TD of 6,000 feet. The objective of this well was to test zones that were impractical to test in, or not penetrated by, the PD-1 and PD-2 wells. The timing of the well was driven by lease obligations, in order to secure the western-most “B&N” lease parcel which likely hosts potential for commercial resources from the Lower Antelope Shale and possibly the Lower Stevens Sand.

The well encountered a number thin gas-bearing sands of the San Joaquin and Etchegoin formations; typical of sands that have produced in the area. Testing of one of these shallow sands resulted in a maximum, unassisted flow of 2.2 MMcfd (million cubic feet) of gas, however the size of the resource is believed to be of limited areal extent. Neon expects to be able to commercialise the gas on the back of of a Paloma Deep development. Two further sands remain to be tested at the appropriate time.

7. DEVELOPMENT OF UNCONVENTIONAL RESOURCES

Commercialisation of North America's vast unconventional hydrocarbon resources has accelerated at a rapid pace, with a recent renewed focus on oil. Utilisation of horizontal drilling coupled with multi-stage fracture stimulation (and other stimulation techniques) has become commonplace across numerous unconventional plays, including oil shales and low permeability sandstones. Consequently, unconventional production has increased to more than 2 MMbopd and is predicted to grow to beyond 4 MMbopd by 2016[1]. As a result of this rapid increase in unconventional resource development, US oil production actually increased in 2011 for the first time in 24 years[2], with the International Energy Agency recently predicting that US oil production could exceed that of Saudi Arabia within the next 6 years[3].

The reservoir objectives at Paloma, between the Upper Antelope Shale down to the Fruitvale Shale, are members of the Monterey Formation. The Monterey is an emerging unconventional play that has recently become the subject of significant industry interest, prompting a "land grab" for petroleum leases and high demand for oilfield services. While conventional zones within the Monterey Formation have been produced for many years, it is only recently that the potential for development of the unconventional shales and low permeability sandstones has been recognised. The US Energy Information Administration[3] estimates that the Monterey play hosts nearly 14 billion barrels of unproved "technically recoverable resources" of tight oil which compares to 5.4 billion barrels and 2.5 billion barrels for the better known Bakken and Eagleford shale plays respectively.

	Play	Formation Depth	Gross Thickness	Matrix Porosity	Matrix Permeability	Total Organic Carbon	US EIA Potential[4]
		(ft)	(ft)	(%)	(md)	(%)	TRR (MMbbls)
High Profile US Oil-Prone Shale Plays	Bakken	7,000 - 11,000	20-150	3-12	0.005 - 0.2	2 - 18	5,372
	Eagle Ford	8,000 - 14,000	75-300	3-15	<0.0001 - 0.003	2 - 6	2,461
	Niobrara	2,000 - 8,000	>150	4-8	0.0002	3 - 5.8	6,500
California San Joaquin Shale Plays	Monterey	5,000-13,000	500-5,000	15-30	0.0001 - 2	0.1 - 4	13,709
	Kreyenhagen	3,000 - 19,000	400 - 2,400	5 - 10	<0.0001 - 1	4 - 12	NA
Paloma Deep Monterey Shale Members	Lower Antelope	11,700 - 12,250	550	9 - 13	0.0006 av	1 - 5.2	NA
	Fruitvale Shale	13,000 - 14,500	1,500	15 - 17	0.0013 av	0.2 - ?	NA

The Paloma leases are well positioned within the Monterey play fairway, and are surrounded by significant exploration and development activity by the likes of large companies such as Occidental and Aera (a Shell/ExxonMobil California joint venture).

The closest analogue unconventional field development in the San Joaquin Basin is Occidental's North Shafter Field, 35km north of Paloma Deep. This has produced over 12 MMbbls of oil since inception in 1983 but the production was only really ramped up from 1998 onwards with the introduction of horizontal drilling and stimulated completions. The oil is produced from the McClure Shale, which is the same rock unit as the Antelope Shale in Paloma Deep though somewhat shallower. Initial production from the horizontal wells is typically 400 to 600 Bopd, with a decline to approximately 100 Bopd after a couple of years.

(1) Review of Emerging Resources: US Shale Gas and Shale Oil Plays, July 2011

(2) http://www.energybulletin.net/stories/2012-12-19/future-production-from-u-s-shale-or-tight-oil

(3) US Energy Information Administration/Annual Energy Outlook 2012.

8. PALOMA RESOURCE POTENTIAL

Neon previously reported its Contingent Resource estimate for Paloma in its announcement to the ASX of 21 June 2012, as per the table below.

Estimated Recoverable Contingent Resource (100%)*				
	Formation	**Low (1C) MMbbls**	**Best (2C) MMbbls**	**High (3C) MMbbls**
Oil	Lower Antelope Shale	5	12	22
	Lower Stevens "B"/Fruitvale	5	14	25
	Total	***10***	***26***	***47***
	Formation	**Low Bcf**	**Best Bcf**	**High Bcf**
Gas	Lower Stevens "B"	8	22	44

This resource estimate will be updated once the remaining pressure data from the PD-2 well has been collected. It is anticipated that the Lower Antelope contingent resource range will remain similar to that previously quoted.

Based on the encouraging result at PD-1 it was believed that the Lower Stevens "B" Sand would be developed conventionally, however in the event that the PD-2 result is indicative of the zone regionally, the resource potential will likely change to reflect unconventional development. In this case, the lower recovery per well associated with tight reservoirs may be offset by a larger drainage area being present as the pay zone is not constrained in a structural sense. At this stage it is premature to speculate further and an update will be issued in due course once the necessary analysis is complete.

9. CONCLUSIONS

The Paloma Deep discovery represents a significant in-place resource of oil and associated gas, likely of the order of 200 to 300 MMBOE (million barrels of oil equivalent).

Production testing operations in both the Paloma Deep wells recovered hydrocarbons at low but stable rates, and this is consistent with low permeability "unconventional" reservoirs. The Lower Stevens "B" Sand in Paloma Deep-1, flowed oil at up to 226 barrels of oil per day before the test ceased prematurely, leading Neon to believe that potential existed for conventional development of that zone. However testing of the same zone in Paloma Deep-2 suggests the reservoir may be of variable quality, and for the most part unconventional in nature. If this is confirmed to be the case, the Lower Stevens will need to be developed via unconventional development, similar to that envisaged for the Lower Antelope and Fruitvale Shales.

The shallower Paloma Sands have yet to be tested in PD-1 or PD-2 wells, and may contain conventional hydrocarbon pay that was bypassed during previous production operations. For operational reasons testing of the Paloma Sands has been postponed until the forward programme for the project as a whole is determined.

The previously quoted Contingent Resource estimates provided by Neon are under review subject to final data acquisition and analysis, and may be subject to some change. However Neon maintains its belief that potential exists for commercial development, and that the size of the potential resource is material to the Company.

The challenge now is to determine a development strategy that will maximise hydrocarbon recovery while containing the unit cost of production, such that commercial development can begin and the value of the asset be maximised.