Buffalo resource: 31 million barrels (2C)

28 August 2017

CARNARVON PETROLEUM LTD

Highlights

- Buffalo field contains a best estimate resource (2C) of 31 million barrels of light premium oil
- State of the art seismic processing has provided greater clarity around the reservoir structure; leading to mapping of unproduced oil in higher structural locations immediately south and east of the previous production area
- Dynamic field simulation modelling reconciles with the new 3D seismic mapping
- RISC has independently audited Carnarvon's technical work and volume estimates
- Field redevelopment supported by scoping economics and will form basis of next updates

Carnarvon Petroleum Limited ("Carnarvon") (ASX:CVN) is pleased to provide the following update on its 100% held Buffalo project in WA-523-P (also refer to updates on 15 May 2017, 23 June 2017 and 31 July 2017).

The independently audited volumetric estimates of contingent resources in the Buffalo oil field comprise:

	1C	2C	3C
Contingent Resource Estimate (Millions of Barrels of Oil)	**15.3**	**31.1**	**47.8**

The best estimate (2C) of recoverable oil of 31 million barrels has a revenue generating capacity of approximately US$1.5 billion to Carnarvon (100%) at current oil prices. There is a range of options to redevelop the field and scoping studies show that the redevelopment of the Buffalo oil field is economic at current oil prices; even at the 1C outcome. This indicates the project to be low risk, and gives Carnarvon the confidence to advance the project immediately.

Upgrading these contingent resources to reserves requires a commitment to develop, encompassing a field development plan and a production license across the Buffalo field. Work on both of these is underway and will form the basis for the next series of project updates.

Carnarvon's Managing Director and Chief Executive Officer, Mr Adrian Cook said "*A great deal of work has gone into de-risking the Buffalo project. This included engaging independent experts to cross check a significant proportion our work in order to give us the highest possible level of confidence in the remaining oil recoverable from this field. The next steps will focus on the field redevelopment and include securing a production licence and associated approvals, advancing redevelopment plans and supplier commitments and finalising funding for the redevelopment activities. While significant work is still required, we are incredibly encouraged by the potential and are pushing forward with the view to bringing the Buffalo field into production.*"

Yours faithfully

Adrian Cook
Managing Director

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Company Secretary
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Resource Information & Cautionary Statement

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognised as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way.

The estimates of contingent resources included in this report have been prepared in accordance with the definitions and guidelines set forth in the SPE-PRMS.

A combination of deterministic and probabilistic methods were used to prepare the estimates of these contingent resources.

Competent Person Statement Information

The resource estimates outlined in this report were compiled by the Company's Chief Operating Officer, Mr Philip Huizenga, who is a full-time employee of the Company. Mr Huizenga has over 20 years' experience in petroleum exploration and engineering. Mr Huizenga holds a Bachelor Degree in Engineering and a Masters Degree in Petroleum Engineering. Mr Huizenga is qualified in accordance with ASX Listing Rules and has consented to the form and context in which this statement appears.

Forward Looking Statements

This document may contain forward-looking information. Forward-looking information is generally identifiable by the terminology used, such as "expect", "believe", "estimate", "should", "anticipate" and "potential" or other similar wording. Forward-looking information in this document includes, but is not limited to, references to: well drilling programs and drilling plans, estimates of reserves and potentially recoverable resources, and information on future production and project start-ups. By their very nature, the forward-looking statements contained in this news release require Carnarvon and its management to make assumptions that may not materialize or that may not be accurate. The forward-looking information contained in this news release is subject to known and unknown risks and uncertainties and other factors, which could cause actual results, expectations, achievements or performance to differ materially, including without limitation: imprecision of reserve estimates and estimates of recoverable quantities of oil, changes in project schedules, operating and reservoir performance, the effects of weather and climate change, the results of exploration and development drilling and related activities, demand for oil and gas, commercial negotiations, other technical and economic factors or revisions and other factors, many of which are beyond the control of Carnarvon. Although Carnarvon believes that the expectations reflected in its forward-looking statements are reasonable, it can give no assurances that the expectations of any forward-looking statements will prove to be correct.

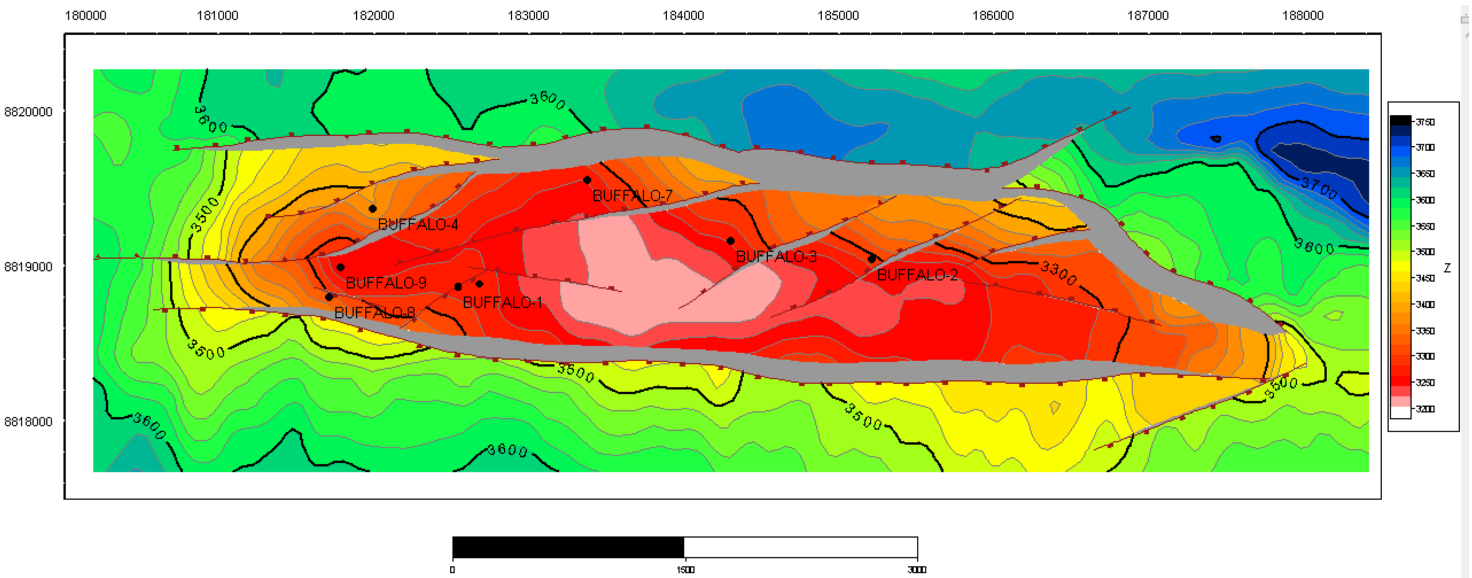
Technical Summary

The Buffalo oil field was discovered with the drilling of the Buffalo-1 well in 1996. One further appraisal well was drilled before a commitment was made to develop the field with two wells tied back to an FPSO with first oil in 1999. A further two infill wells were drilled in 2002 with the production ceasing in 2004 when the field was still producing around 4,000 bopd. Total production from the field until 2004 was just over 20 million barrels of oil. The field was abandoned and all infrastructure removed.

The Buffalo reservoir is world class, with the original development exceeding 50,000 bopd from two wells within 48 hours of coming onstream. The oil is a premium light oil with an API of 53 degrees. The Buffalo 3, 5, 7 and 9 wells were the only production wells.

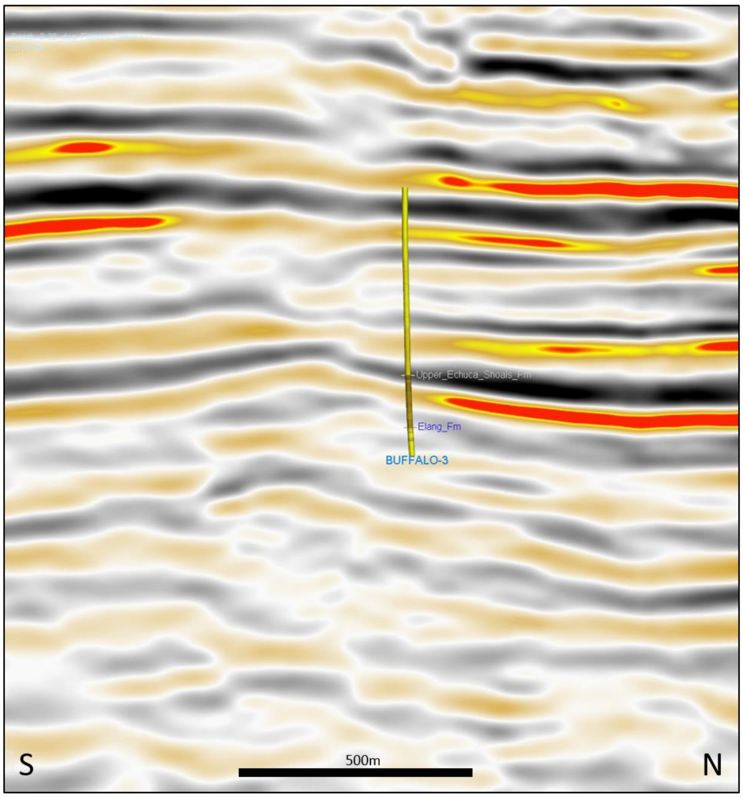
Carnarvon Petroleum acquired the WA-523-P exploration permit, containing the Buffalo oil field, in 2016 with the primary work program being to better interpret the top reservoir of the three known oil accumulations in the block, the Bluff and Buller oil columns and the Buffalo oil field. Seismic interpretation of these structures has historically been challenging because of the interference of many sub-sea banks, some rising from 300 metre water depth to just below surface level. These banks cause difficulty in interpretation because of the poor signal penetration and hence very low top reservoir reflectivity.

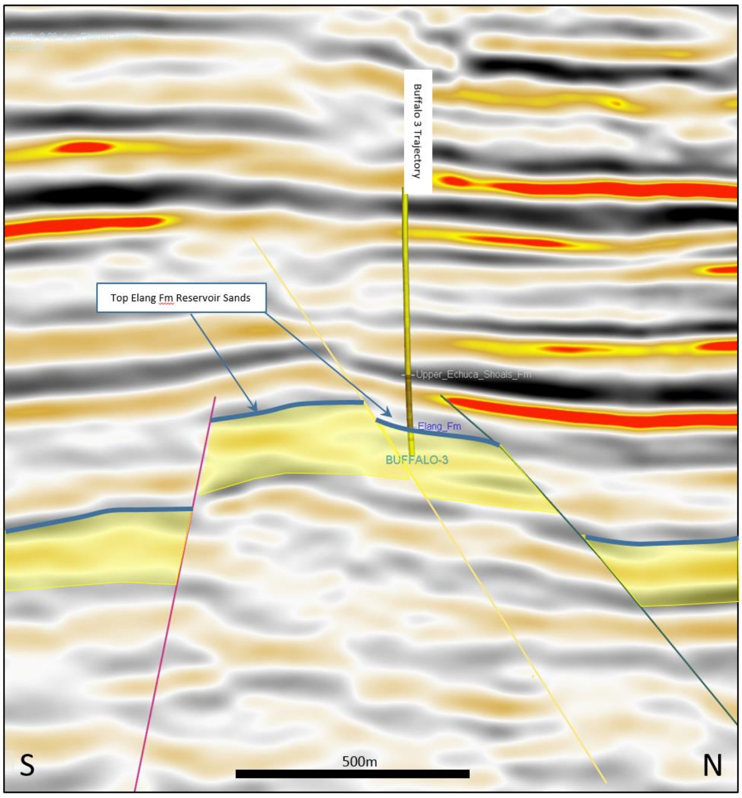
The 3D seismic in the permit was reprocessed through the application of Full Waveform Inversion (FWI), supported by refraction and reflection tomography resulting in a more accurately derived velocity field. A new structure map was derived from this 'data-driven' process and tied to the available well data.



This revised structure map, as depicted above in the interpreted Top Elang Formation target reservoir depth map, clearly demonstrates a significant amount of attic oil above the previously highest known oil, and an additional accumulation of oil in the East of the structure. Based on this advanced interpretation, the previous wells were mostly drilled in the northern and western flanks of the structure and close to the interpreted oil-water contact.

The revised interpretation indicates an additional 50 to 60 metre oil column in the crest of the field.

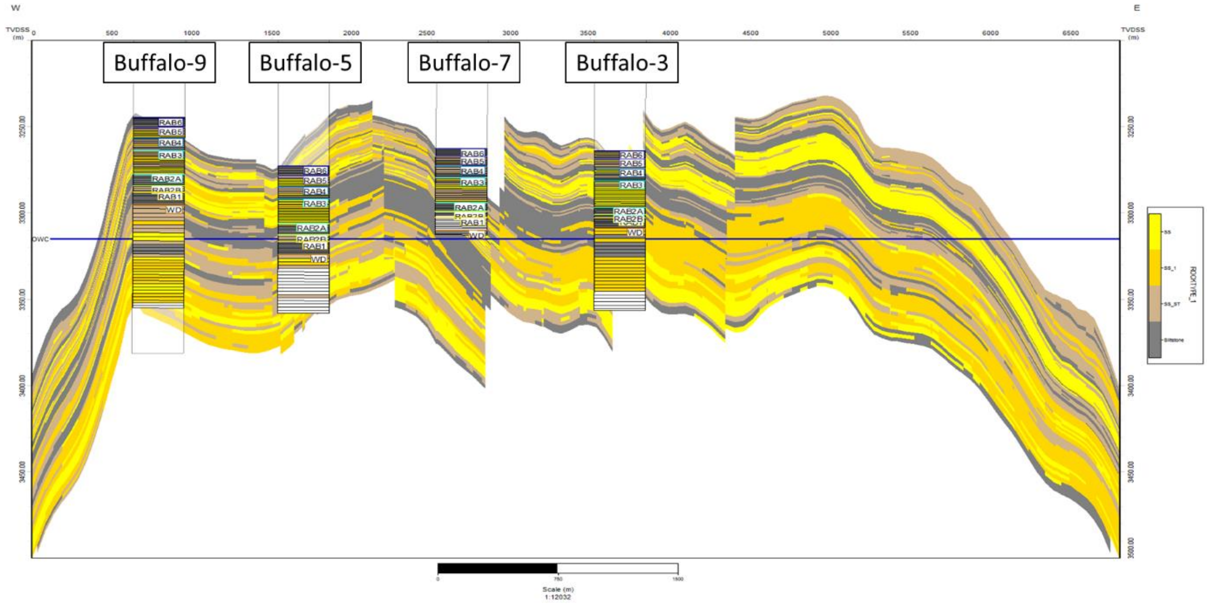




The above North-South seismic line demonstrates that Buffalo-3 well missed the crest of the Buffalo structure. The crest or structural attic of the Buffalo field is approximately 250m South of the Buffalo-3 well. The seismic lines above are identical, with the line on the right having Carnarvon's interpretation of the reservoir sands.

Using this revised depth structure map, and the geological information from the eight wells that have penetrated the field, a detailed 3D geological model was created to determine the range of potential oil in place.

The geological attributes of the Buffalo field reservoirs can be accurately described from the eight wells that have penetrated the field. Since each of the wells is similar in nature, and can be easily correlated, a reasonably accurate model using the revised mapping was constructed.



Significant technical work underpins the detailed geological model of the field, with the above cross section of the individual sand bodies modelled as an example of some of the inputs into the model.

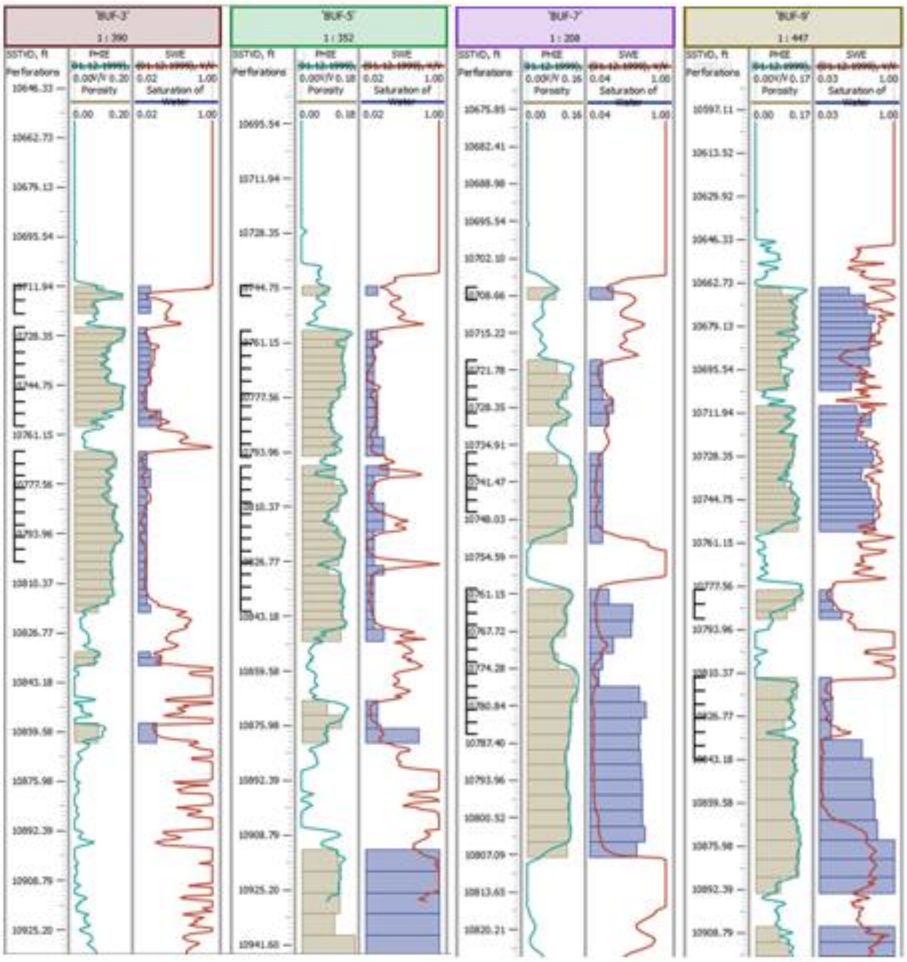
In order to capture some of the uncertainty in the mapping and geological understanding, around 500 iterations of the model were created by varying the model attributes away from the well control points. Porosities, saturations, net to gross etc. and the structure map were varied within reasonable limits to achieve a range of geological models that encompasses the low to high cases.

It was also critical to demonstrate that the range of geological models also fit the historical production data and pressure measurements. To this end a number of dynamic reservoir simulation models were constructed based on low, mid and high geological models, to determine whether the presence of an additional accumulation of attic oil would accurately explain the historical performance of the field on a retrospective basis.

The critical areas that required careful matching to ensure that the models were indicative of actual performance were:

- Initial hydrocarbon saturations matched the wells for the date of drilling (i.e. some wells were drilled prior to production and other wells after some oil had been produced);
- The pressure data collected from the Buffalo-9 well which exhibited very minor pressure depletion even though this well was drilled after the field had already produced 13 million bbls of oil;
- Indications from well data that all wells and reservoir levels were in communication; and
- Matching of oil and water produced through the production history.

These inputs were matched with a comfortable degree of accuracy. Importantly there was close match to the production history for the central well closest to the newly interpreted attic across the range of oil in place models, indicating that the presence of additional attic oil is consistent with the available field well and production data history.



Comparison between actual log saturations (red line) and dynamically simulated hydrocarbon saturations (purple bars) for the two wells drilled (Buffalo-3 & 5) ***prior*** to field commencement showing excellent correlation.

Comparison between actual log saturations (red line) and dynamically simulated hydrocarbon saturations (purple bars) for the two wells drilled (Buffalo-7 & 9) ***after*** production had commenced showing good correlation.

Having history matched the dynamic models, three hypothetical new, approximately crestal wells were placed in the models to see how they would produce from each of the low, mid and high case models. The forecast production from these three new wells demonstrates recovery factors consistent with surrounding fields. Good reservoir and strong aquifer will mean any initial well flow rates will be high – as demonstrated by the original Buffalo field development where the production from first two wells totalled around 50,000 bopd.

Using a range of recovery factors estimated from nearby analogue fields, encompassing the recovery demonstrated from the dynamic models, a range of contingent resources for the WA-523-P was estimated to be:

Resource Category	Oil (MMstb)		
	1C	2C	3C
Contingent Resources	15.3	31.1	47.8

Notes:
1. The contingent resources have been evaluated using a combination of probabilistic and deterministic methods
2. The contingent resource are classed as Project Maturity Status Development Unclarified/On Hold
3. There are no gas or condensate resources
4. There is no certainty that these contingent resources will be commercially viable to produce any portion of the resources and it should be noted that it is not certain that projects will progress to reserves status

Carnarvon engaged RISC Operations Pty Ltd (RISC) to undertake an independent evaluation of the resources to support further development plans. RISC has provided a certification letter on the Buffalo oil field to SPE-PRMS standards and is attached as an Appendix to this announcement.

The results of the geological and engineering models demonstrate, with a sufficient level of comfort for independent auditing, that the most recent mapping honours the available well, production and pressure data and indicates a substantially increased commercial oil accumulation for future production.

26 August 2017

Mr. Philip Huizenga
Chief Operating Officer
Carnarvon Petroleum Pty Ltd
250 St. Georges Terrace
Perth, WA., 6000

Dear Mr. Huizenga

Audit of Carnarvon Petroleum's contingent resources at Buffalo Field as at 1 August 2017

At the request of Carnarvon Petroleum Pty Ltd (Carnarvon), RISC has audited the 1C, 2C and 3C contingent resources for Carnarvon's Buffalo field in Bonaparte Basin offshore Western Australia (Figure 1).

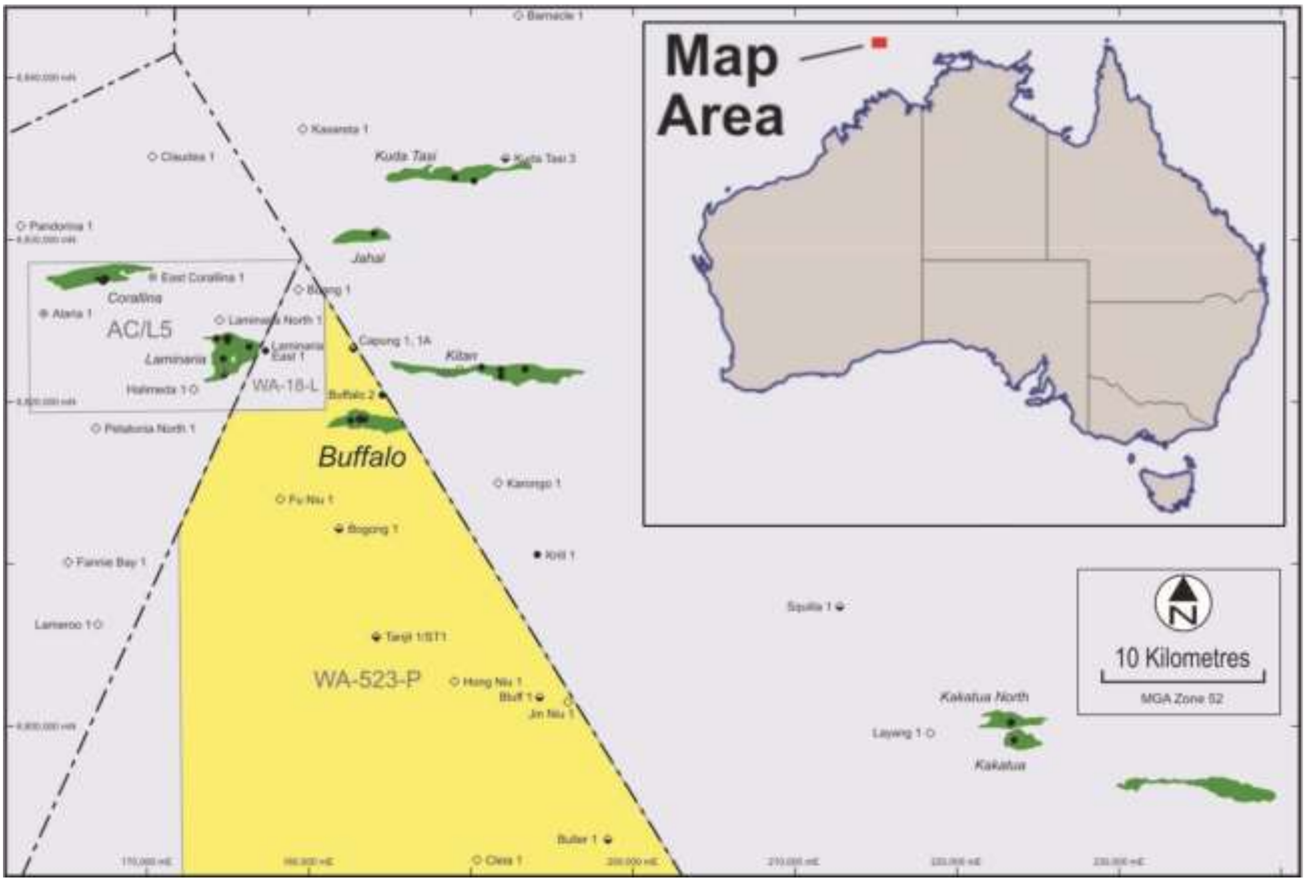


Figure 1: Location of Buffalo Field

The audited contingent resources net to Carnarvon as at 1 August 2017 are set out in Table 1 below. There is no reconciliation of changes with previous resource estimates as resources were not previously assigned. Table 2 contains the tenement details and Carnarvon working interest.

Table 1: Net unrisked 2C contingent resources for Buffalo Field attributable to Carnarvon Petroleum Limited as at 1 August 2017

Resource Category	Oil (MMstb)		
	1C	2C	3C
Contingent Resources	15.3	31.1	47.8

Notes:
1. The contingent resources have been evaluated using a combination of probabilistic and deterministic methods
2. The contingent resource are classed as Project Maturity Status Development Unclarified/On Hold
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Table 2: Tenement Details and Working Interest

Permit	Carnarvon Interest	Operator Group	Basin	Type	Area (km^2)	Awarded	Expires	Notes
WA-523-P	100.000%	Carnarvon Petroleum	Bonaparte	Exploration Permit	4246.4	27/05/2016	26/05/2022	Year 1-3: Spend $2.830 million 1615 sq km 3D seismic reprocessing, licence 3000 km 2D seismic, remapping of reprocessed 2D & 3D seismic, studies

Audit Opinion

We have examined Carnarvon's estimates of contingent resources for the Buffalo Field. The tenement details and working interest of the exploration properties evaluated by RISC are shown in Table 2.

It is our opinion that the contingent resources shown in Table 1 are reasonable and have been prepared in accordance with the definitions and guidelines contained within the Petroleum Resources Management System (PRMS)[1] and generally accepted petroleum engineering and evaluation principles as set out in the SPE Reserves Auditing Standards[2] An extract of the PRMS definitions are included in Appendix 1.

The Buffalo oil field was developed by BHP and produced 21 MMbbls between Dec-1999 and Nov-2004. The wells were subsequently abandoned and facilities removed. Carnarvon have reprocessed and merged three 3D seismic survey with combined area of 1927 square km, re-mapped and re-modelled the Buffalo field and interpret updip oil that has not been developed. These contingent resources are attributed to the potential re-development of Buffalo field. Resources are classified as contingent resources (development unclarified) as the potential re-development concept has not been finalized or sanctioned.

A summary of the audit procedures is set out below.

Audit procedures

RISC was provided with information including well reports, seismic data, well log and core data, maps, interpretation reports, well completion data, production and pressure information, fluid composition and properties, production decline analysis, static and dynamic models. The information provided to RISC has

[1] *Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG) and approved by the Board of the SPE in March 2007.*

[2] *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information Approved by SPE Board in June 2001, revised Fenruary 19 2007*

included hard copy only supplemented with discussions and workstation reviews between RISC and representatives of Carnarvon.

Production databases were provided by Carnarvon. RISC has not audited the production databases as this was outside of our terms of reference.

The information was reviewed for its quality, accuracy and validity and was considered to be acceptable. If, in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data.

Our examination included an assessment of the classification and categorization of the contingent resources. We are satisfied Carnarvon has correctly classified the resources as contingent resources in accordance with the PRMS. Carnarvon's methods have incorporated a range of uncertainty to allow the correct assignment of the estimates into 1C, 2C and 3C contingent resource categories in accordance with the PRMS.

RISC has not made a physical inspection of the properties as this was not considered necessary for our assessment.

Carnarvon has used a combination of volumetric methods, decline analysis, reservoir simulation and history matching and the performance from offset wells and analogous projects. RISC reviewed the methodology and analysis carried out by Carnarvon to estimate contingent resources and considers them to be consistent with the generally accepted petroleum engineering and evaluation principles as set out in the SPE Reserves Auditing Standards.

Economic evaluation has not been conducted as re-development costs are not available. Therefore the economic status is undetermined.

Carnarvons's interest in the permits has been provided by Carnarvon, however RISC has not independently assessed property title and encumbrances as this was outside of our terms of reference. There are no overriding royalties.

Qualifications

RISC is independent with respect to Carnarvon as provided in the SPE Reserves Auditing Standards. RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal or regulatory changes.

It should be understood that our above-described audit does not constitute a complete resource study of the oil and gas properties of Carnarvon. The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from Carnarvon. RISC believes that that full disclosure has been made of all relevant material in Carnarvon's possession and that information provided, is to the best of its knowledge, accurate and true.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, we believe our review and conclusions are sound, but neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters which an extensive examination may disclose. In particular, we have not independently verified property title, carry forward tax balances, encumbrances, regulations, sales and transportation agreements and product prices that apply to these assets.

Our assessment was carried out only for the purpose referred to above and may not have relevance in other contexts. The estimates contained in our assessment may increase or decrease and RISC's opinions may change as further information becomes available.

The preparation of this report has been supervised by Mr Peter Stephenson, RISC Partner. He has over thirty years of global experience in the upstream hydrocarbon industry, with extensive expertise in the areas of reservoir evaluation, field development planning, due diligence assessment for mergers, acquisitions and project finance requirements, resource audit, assessment and preparation of Independent Technical Specialist reports. Mr Stephenson is a Member of the Society of Petroleum Engineers (SPE), Member of the Institude of Chemical Engineers, holds a BSc (Chemical Engineering), University of Nottingham, 1982 and an M.Eng. (Petroleum Engineering), Heriot Watt University, 1984 and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

This report was completed on 26 August 2017.

Yours sincerely,

Peter M Stephenson

Partner

APPENDIX 1 - PRMS PETROLEUM RESOURCES CLASSIFICATION FRAMEWORK AND DEFINITIONS

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide or sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the earth's crust, discovered and undiscovered, (recoverable and unrecoverable) plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional".

Figure A-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources and Prospective Resources as well as Unrecoverable petroleum.

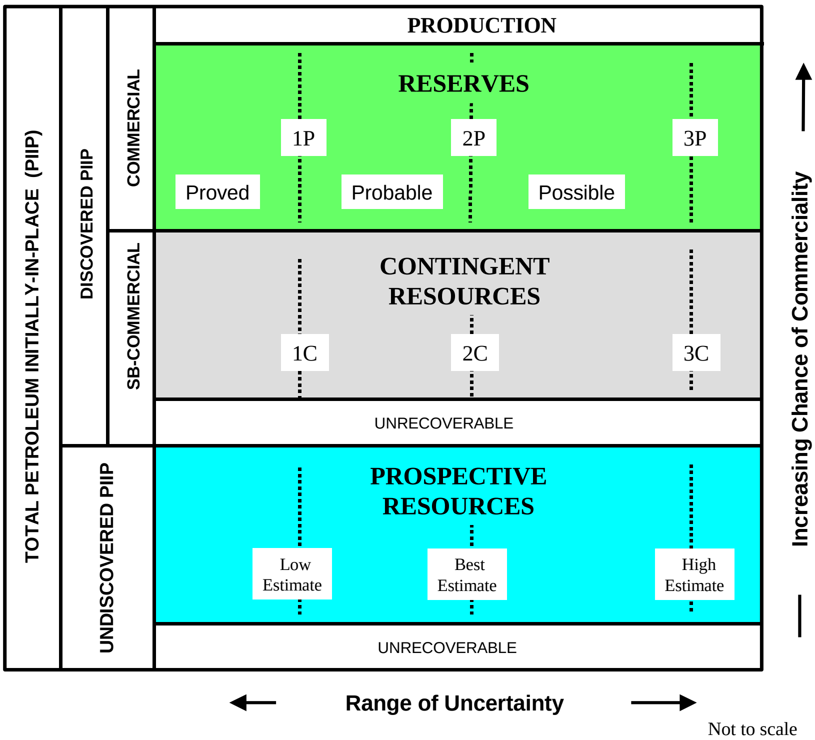

Figure A 1: Resources Classification Framework

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable timeframe.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbonbearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

PROVED RESERVES are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that:

- The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive;
- Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the

Proved area and the applied development program.

PROBABLE RESERVES are those additional Reserves which analysis of geoscience and engineering data Indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

POSSIBLE RESERVES are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

ESTIMATED ULTIMATE RECOVERY (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources and Prospective Resources may be referred to as “remaining recoverable resources”. When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.