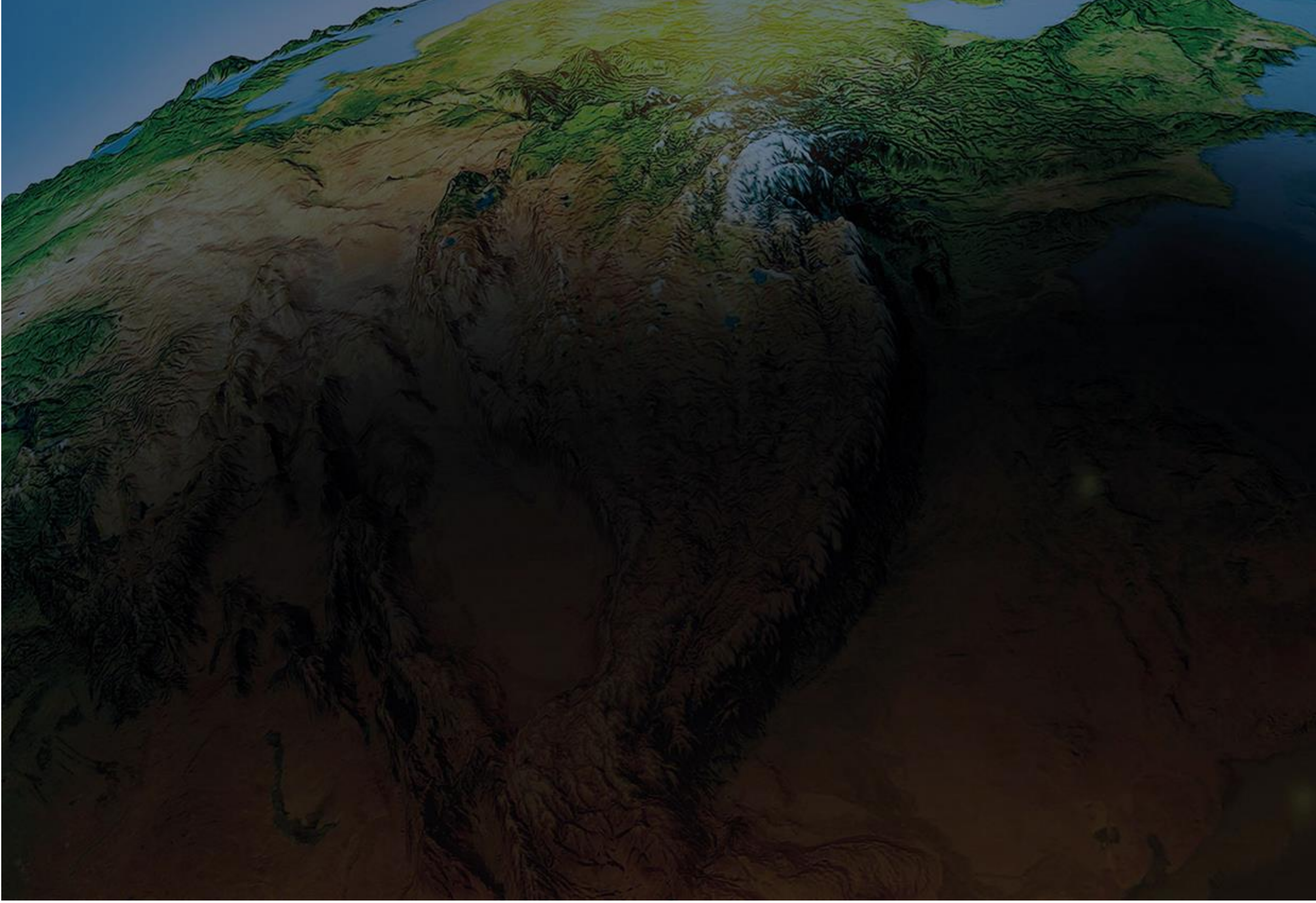
decisions with confidence

Independent Technical Specialist Report

On assets of Larus Energy Limited

For Hall Chadwick Corporate (NSW) Ltd

June 2022



Matthew Azar
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Larus Energy Ltd
Level 28, 140 St Georges Terrace
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Drew Townsend
Director
Hall Chadwick Corporate (NSW) Ltd
Level 40, 2 Park Street
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24 June 2022

Dear Sirs,

Independent Technical Specialist Report – PPL 579.

Larus Energy Limited ('Larus') has engaged Hall Chadwick Corporate (NSW) Limited ('Hall Chadwick') to prepare an Independent Expert Report ('IER') to be provided to the shareholders of the company.

As per the engagement between Hall Chadwick and RISC Advisory Pty Ltd ('RISC') dated 26 May 2022, RISC was engaged to provide a valuation of exploration permit PPL 579 in Papua New Guinea.

RISC has completed our independent technical assessment of the permit and valuation and our work is documented in this Independent Technical Specialist Report ('ITSR').

Independence

RISC confirms that it is independent of both Hall Chadwick and Larus and that RISC is unaware of any circumstance which may compromise that independence.

Consent

RISC has consented to this report, in the form and context in which it appears, being included, in its entirety, to the shareholders of the company.

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1. Executive summary

Hall Chadwick Corporate (NSW) Limited ('Hall Chadwick') has been appointed as the Independent Expert to perform a valuation of the assets of Larus Energy Limited ('Larus').

The principal asset of Larus is a 100% working interest in the PPL 579 petroleum exploration permit in Papua New Guinea. Hall Chadwick has appointed RISC Advisory Pty Ltd ('RISC') as the Independent Technical Specialist to provide an opinion on the value of PPL 579.

The valuation of exploration properties is subject to considerable uncertainty. As required by ASIC RISC has adopted a number of approaches to estimate the value of PPL 579.

RISC has determined that the fair market valuation of Larus's net interest in PPL 579 to be between AU$0 million and AU$12.6 million with a best estimate of AU$3.5 million (Table 1-1).

Table 1-1: PPL 579 valuation net to Larus

PPL 579	Valuation (AU$ million)		
	Low	Best	High
Net Larus	0.0	3.5	12.6

2. Terms of reference and basis of assessment

2.1. Terms of reference

This Independent Technical Specialist Report ('ITSR') was prepared as part of a contract between Hall Chadwick Corporate (NSW) Limited ('Hall Chadwick') and RISC dated 25 May November 2022. Hall Chadwick was engaged by Larus Energy to prepare an Independent Expert Report ('IER') for inclusion in a Notice of Meeting regarding the valuation of Larus Energy.

RISC was requested to prepare a market valuation of Larus Energy's PPL 579 exploration permit in Papua New Guinea which lies to the southeast of Port Moresby, Papua New Guinea and consists of 110 sub-blocks.

As per the instruction from Hall Chadwick the ITSR is compliant with the Australian Securities and Investments Commission ('ASIC') Regulatory Guides 111 and 112, includes a consent for the report to be provided to the shareholders of the company and for RISC to be named as technical specialist/expert in accordance with ASX listing rule 5.41.

2.2. Basis of assessment

The data and information used in the preparation of this report were provided by Larus and supplemented with public domain information.

Our valuation was confined to PPL 579. We have based our valuation on sunk costs to date, what terms we would expect Larus to receive for a farm-out the PPL 579 exploration permit and the probability that a farm-out would complete in a reasonable timeframe.

This involved:

- Discussions with Larus staff on the outcome of marketing efforts to date;
- Consideration of the terms Larus might be able to negotiate with a new participant in the permit, and
- A review of farm-in terms for comparable petroleum exploration permits globally.

RISC has reviewed the exploration resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System ('PRMS')[1].

Details of the findings of our review are presented in this report. Unless otherwise stated, all resources presented in this report are gross (100%) quantities.

RISC has not conducted a site visit and does not consider one necessary.

[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. The PRMS was subsequently updated in June 2018.

2.3. Valuation

The valuation is based on the principles of the VALMIN Code[2] and the concept of "market value" ('Value').

The VALMIN Code defines Value as the estimated amount of money (or the cash equivalent of some other consideration) for which the Mineral Asset should exchange on the date of valuation between a willing buyer and a willing seller in an arm's length transaction wherein the parties each acted knowledgeably, prudently and without compulsion. For the purposes of this report, we have applied these definitions to petroleum properties.

A range of oil and gas industry accepted practices in relation to petroleum properties has been considered to determine Value, which are described below.

2.3.1. Comparable transaction metrics

An estimate of the Value of petroleum properties can be obtained using recent comparable transactions. Such transactions may provide relevant metrics such as value per unit of reserves, contingent or prospective resources and price paid per unit area of the permit/license, or % interest. The VALMIN Code advises Value must also take into account risk and premium or discount relating to market, strategic or other considerations.

2.3.2. Sunk costs and work program

The sunk costs and costs of a future work program may also be used to estimate value. The work program valuation relies on the assumption that unless there is evidence to the contrary the permit is worth what a company will spend on it. This method is relevant for permits in the early stages of exploration and for expenditure which is firmly committed as part of a venture budget or as agreed with the government as a condition of holding the permit. There may need to be an adjustment for risk and the time value of money.

Results as the work program progresses, will alter the perceived value. Therefore, the original work program agreed may no longer represent today's Value.

2.3.3. Farm-in promotion factors

Alternatively, an estimate of value can be based on an estimation of the share of future costs likely to be borne by a reasonable farminee under prevailing market conditions. A premium or promotion factor may be paid by the farminee. The promotion factor is defined as the ratio of the proportion of the activity being paid for and the amount of equity being earned.

The nominal permit value is defined as the amount spent by the farminee divided by the interest earned. The premium value for the permit is the difference between the nominal value and the equity share of the cost of the activity divided by the equity interest being earned.

2 The VALMIN Code sets out requirements for the technical assessment and valuation of mineral assets and securities for independent expert reports, it provides guidance for petroleum assets and securities. The VALMIN Committee is a joint committee of The Australasian Institute of Mining and Metallurgy (AusIMM) and the Australian Institute of Geoscientists. The committee was established to develop and maintain the "Australasian Code for Public Reporting of technical assessments and valuations of mineral assets", commonly known as the VALMIN Code. The VALMIN Code was first published in 1995, with subsequent editions published in 1997, 2005 and 2015

The premium or promotion factor will be dependent upon the perceived prospectivity of the property, competition and general market conditions. The premium value is equivalent to the farminee paying the farminor a cash amount in return for the acquisition of the interest in the permit and is the fair market value.

Farm-in transactions may have several stages. For example, a farminee may acquire an initial interest by committing to a future cost in the first stage of the transaction but has an option to acquire an additional interest or interests in return to committing to funding a further work program or programs.

Farm-in agreements can also include re-imbursement of past costs and bonus payments once certain milestones are achieved, for example declaration of commerciality, or achieving threshold reserves volumes. Depending on their conditionality, such future payments may contribute to Value. However, they may need to be adjusted for the time value of money and probability of occurring.

2.3.4. Expected monetary value

Expected monetary value ('EMV') is the risked net present value ('NPV') of a prospect or project. EMV is calculated as the success case(s) NPV times the probability of success and development less the NPV of failure cases multiplied by the probability of failure. The NPV may be estimated using discounted cash flow ('DCF') methods. The EMV method provides a representative estimate of Value in areas with a statistically significant number of mature prospects or projects within proven commercial hydrocarbon provinces where the chance of success and volumes can be assessed with a reasonable degree of predictability. EMV is appropriate to discovered hydrocarbons where development details and costs are mature. As such RISC does not consider EMV is appropriate for this situation of immature, exploration resources.

The EMV valuation can also be used as a relative measure for ranking exploration prospects within a portfolio to make drilling decisions, assessing commercial potential and to demonstrate the commercial attractiveness of a permit, which may influence a buyer or seller. EMV methodology has not been used for this evaluation.

3. Introduction

Larus Energy Limited (‘Larus’) is an unlisted Australian public oil & gas company with 100% ownership of the PPL 579 exploration permit in Papua New Guinea (‘PNG’). This is the only exploration asset of Larus.

The company has a base in Kupiano (Central Province) and employs twenty local staff undertaking community awareness, Government liaison, security & general technical operations.

3.1. PPL 579, Papua New Guinea

PPL 579 is located to the southeast of Port Moresby (Figure 3-1). Consisting of 110 sub-blocks, the license covers an area of approximately 9,244 km^2 and spans both onshore and offshore regions (Table 3-1). Over half of the license is in the offshore region of the Coral Sea, with a large portion in water depths of 200 m or less, though some of the key prospects are in water depth of greater than 1000m. Larus has 100% interest in PPL 579 and to date has conducted extensive geological and geophysical studies.

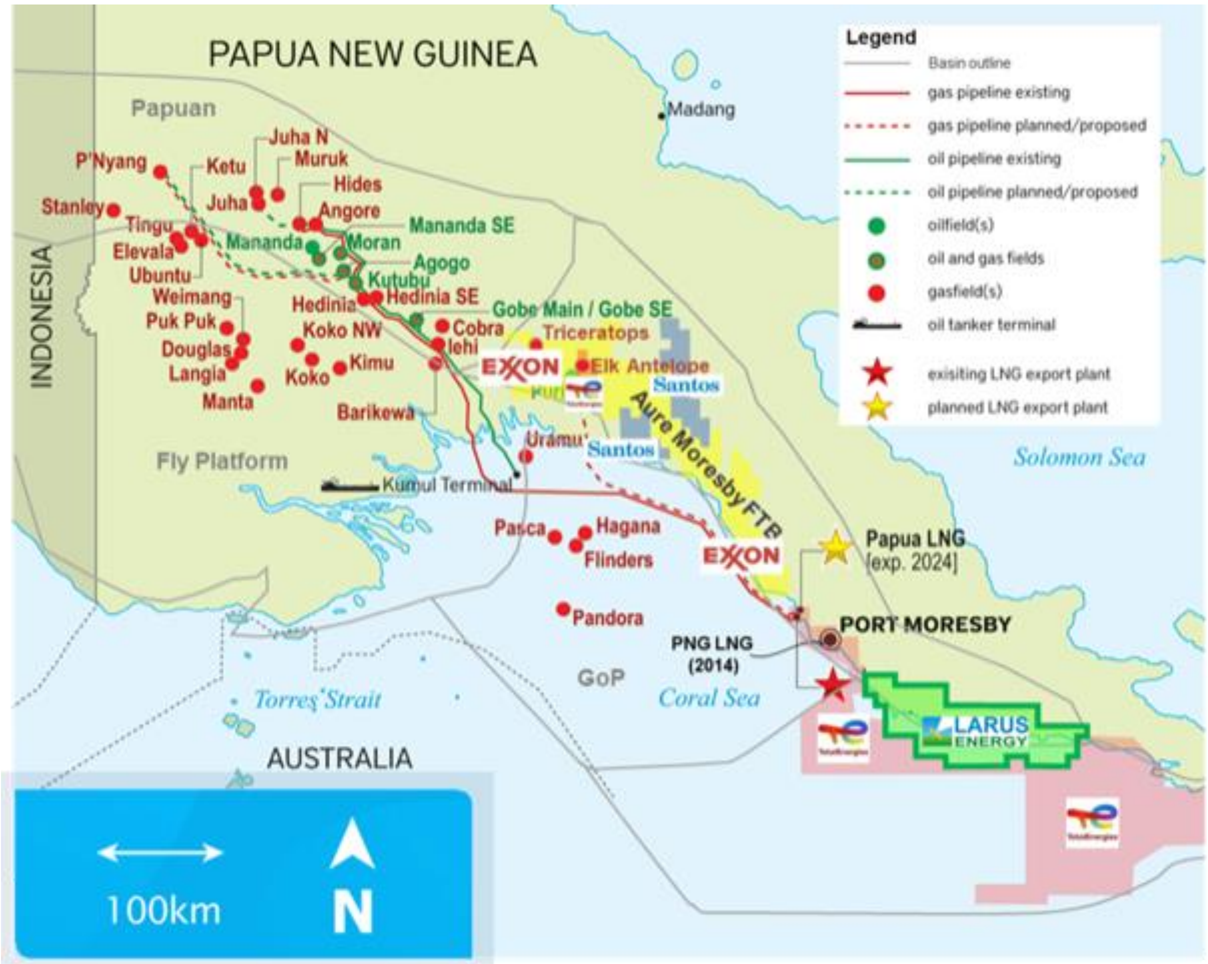

Figure 3-1: PPL 579 exploration permit location map

Table 3-1: PPL 579 asset summary

Asset		Operator	Larus Energy Working Interest	Status	Licence expiry date	Licence area (km^2)
Country	Permit					
Papua New Guinea	PPL 579	Larus Energy	100%	Exploration	March 2028	9,245

Notes to the table:

1. License term is 11-years beginning March 2017, consisting of an initial period of 6-years to March 2023 with an ability to renew for a further 5-year term.
2. The license is partially onshore (approximately 47% of the area) and offshore (approximately 53% of the area).
3. Prospect risks exist in hydrocarbon source, migration, reservoir, trap and containment risk categories.

The prospectivity assessment of the license is now at a stage of evaluation maturity where RISC consider that 3D seismic is required before a decision to drill an exploration well is made.

Larus is aligned with this assessment and intends to bring in investor(s) to the license, preferably with operating expertise, to proceed to this next stage of evaluation. Larus anticipate that an incoming party will fund the acquisition of a 3D seismic survey ('seismic option') in return for an option to participate in the drilling of an exploration well in the license. RISC has taken account of this farm-out approach in our valuation.

Larus has commenced a process to identify and attract potential partners.

4. Regional setting

Many petroleum discoveries have been made in PNG, the majority of which are onshore in the highlands of the Papuan Basin (refer Figure 3-1).

4.1. Papuan Basin

The petroliferous Papuan Basin can be sub-divided into four main geological areas based on hydrocarbon exploration, discovery, development, and production (Figure 4-1). These are:

- Papuan fold thrust belt ('PFTB')
- Papuan foreland
- Aure fold and thrust belt ('AFTB')
- Gulf of Papua ('GoP')

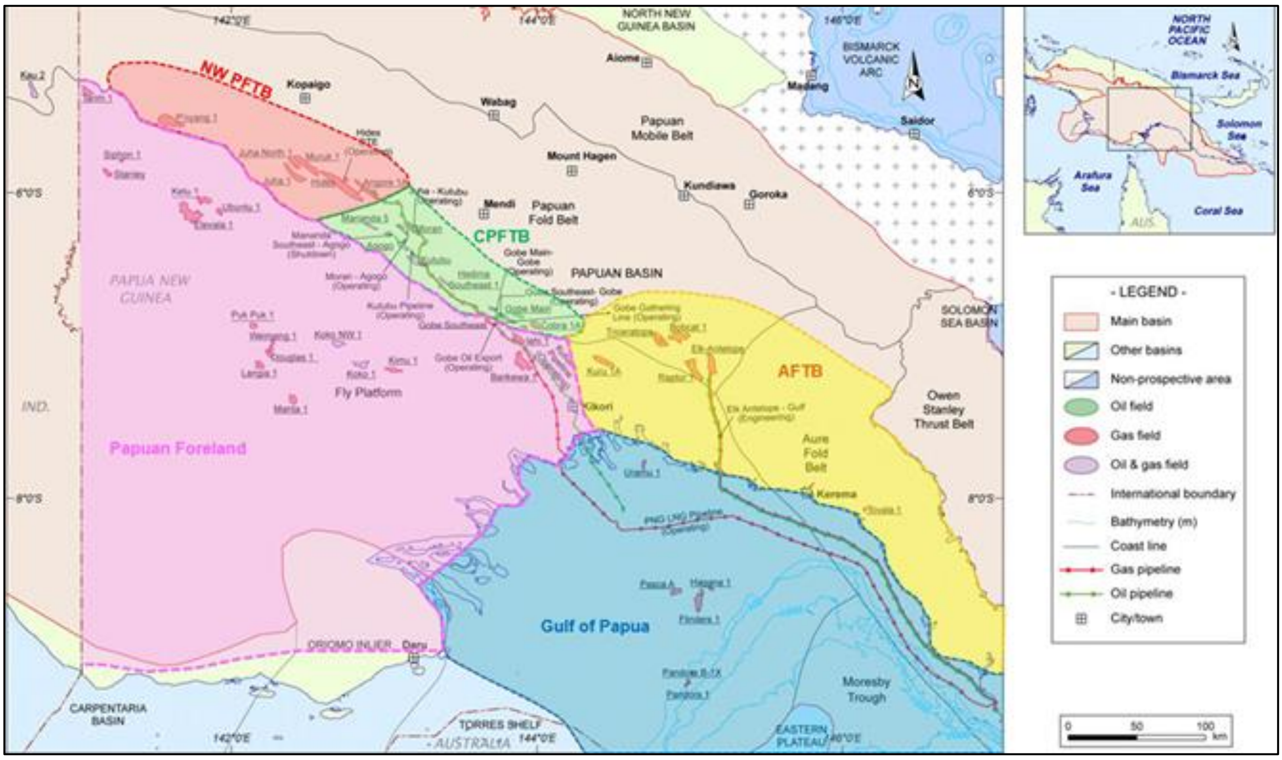

Figure 4-1: Map of Papuan Basin [3]

The key geological elements that control hydrocarbon accumulations in the Papuan Basin evolved over the initial Permian–Triassic basement rifting, post-sedimentation inversion involving folding and faulting largely due to the south - southwest propagation of the Pacific tectonic plate towards the stable Australian craton.

[3] Noku, S.K. Structural Traps and Hydrocarbon Resources of the Papuan Basin: An Overview. AAPG Search and Discovery Article #11325 (2020). AAPG/EAGE PNG Geoscience Conference & Exhibition,

Reactivation of basement faults during the Late Cretaceous eastern Australia extension has played significant role in configuration of the Papuan Basin structural plays (Figure 4-2). Late Jurassic–Early Cretaceous marine siliciclastic reservoirs are the primary play targets.

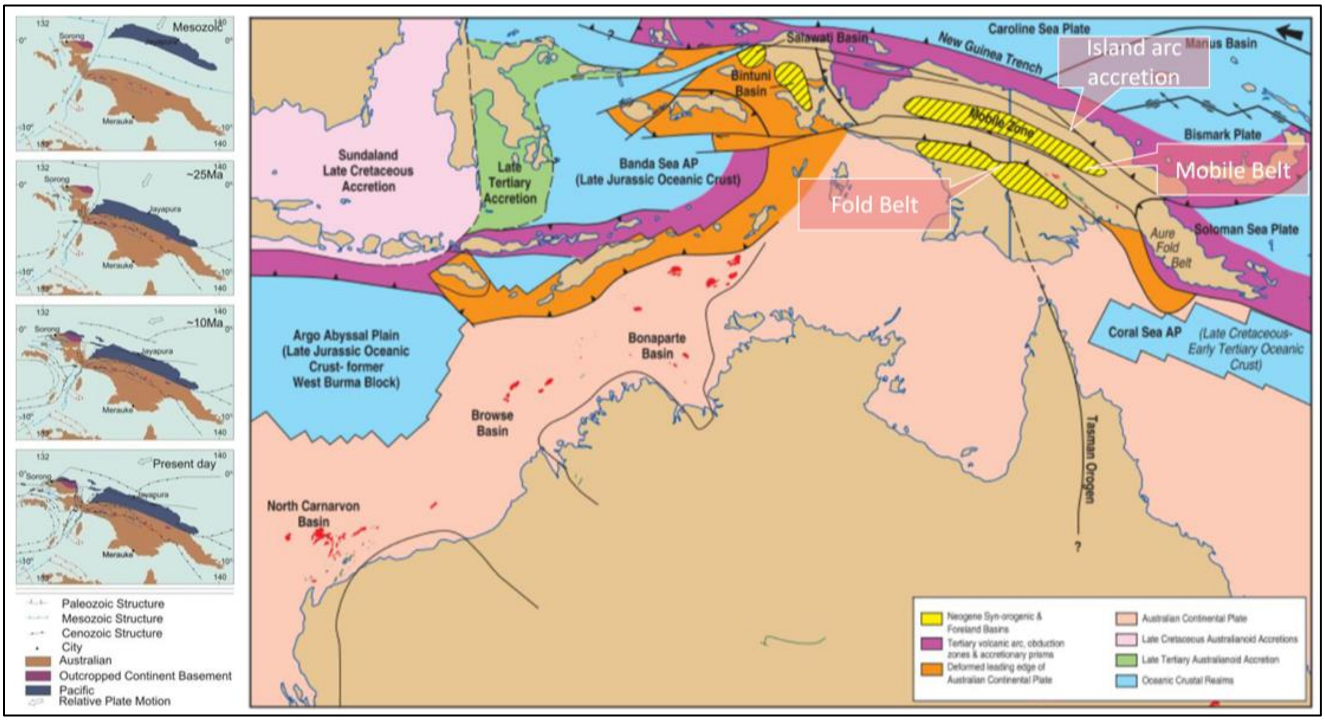

Figure 4-2: Regional tectonic evolution of the Papuan Basin [3]

4.2. Aure Moresby fold thrust belt (ATFB)

The ATFB (sometimes also referred to as the Aure Moresby fold and thrust belt), located to the north-west of the PPL 579 license, contains the Elk - Antelope Field in Miocene aged carbonate reservoirs. Other sub-commercial discoveries and exploration wells with shows exist, but there are yet to be any wells in the Eastern Aure fold thrust belt. The ATFB is interpreted to extend into the PPL 579 license.

The ATFB is a complex structural zone where regional tectonic elements change orientation from a northwest – southeast orientation to a more north-south orientation. Onset of Tertiary transpressional deformation of ATFB crosscuts older structures developed by arc-continental collision in the highlands of the PFTB. Shallow thrust detachment faults were reactivated by basement faults during the Pliocene. The thrusted platform slope and reefal Miocene carbonates become the primary play in the region.

Recent literature[4] cites the ATFB is considered to be the result of thin-skinned deformation along Late Cretaceous, Miocene and Pliocene detachment levels affected by recent thick-skinned deformation. The section is characterized by multiple fault-propagation folds detached at various level within the Mesozoic and Cenozoic.

[4] Kergaravat, C. Evolution of the Aure-Moresby Foreland FTB (Papua New Guinea): Constraints from balanced crustal scale cross-section and forward modeling. 22nd EGU General Assembly, held online 4-8 May, 2020

4.3. Gulf of Papua (GOP)

Recent seismic data acquired by Searcher Seismic over the Gulf of Papua ('GoP') has revealed new potential for hydrocarbon accumulations. This high-quality seismic dataset has enabled more comprehensive play identification in deep to shallow waters of GoP. Structures associated with the basement rifting with post-rift carbonate and turbidite siliciclastic deposition are the key exploration plays.

The offshore Pasca, Pandora and Uramu gas field discoveries were made on Miocene reefal carbonate build-ups on faulted basement highs in the GOP. The carbonate and siliciclastic plays are estimated to have a combine resource of up to 306 MMboe of gas/condensate.

The underexplored (and undrilled), Papuan Plateau is a frontier region in the Coral Sea and is located to the south of the PPL 579 license. Multiple exploration play types are recognized, including Neogene turbidite and Paleogene carbonate plays. TotalEnergies hold a large acreage position and have matured the ready to drill '*Mailu*' prospect in Paleogene carbonates to the south-east of the PPL 579 license.

5. PPL 579 exploration license

No petroleum wells have been drilled in the license area to date and wells drilled within the ATFB are located more than 150 km from the license.

Structural interpretation based on ship-borne gravity and magnetic data along with approximately 7,620 km of 2D seismic which were purchased by Larus consist of multiple vintages of surveys and includes some modern Pre-stack depth migration ('PSDM') processing.

5.1. Work program and commitments

A summary of the proposed forward work program activities for PPL 579 are shown in Table 5-1. None of these activities are outstanding firm work program commitments of the license. Larus have advised that all work program commitments of the current term have been satisfied.

Table 5-1: PPL 579 proposed work program (Larus)

Project	Range of Expenditure AU$ million (Larus)	Minimum Expenditure AU$ million (RISC)
3D seismic acquisition, 1,950 km^2 offshore	14 - 20	16.7
Exploration well	42 - 70	42.0

The planned seismic survey covers a significant portion of the offshore area of the license. There is an opportunity to optimise (reduce) the survey area around the most prospective area of the license to reduce costs. The proposed exploration well cost estimate appears reasonable.

5.2. Past costs

Larus have provided a summary of past costs dating to 2009. Total past costs are AU$14.1 million, comprising seismic costs (AU$4.7 million), other work program (AU$0.6 million), consulting fees, office costs and other general and administration costs.

5.3. Prospects and leads

Larus have generated a portfolio of 29 prospects and leads including stacked reservoirs across 3 interpreted depositional systems with System 2 being the primary reservoir target (Figure 5-1). A deep water turbidite depositional system has been interpreted by Larus from limited 2D seismic for all three reservoir depositional systems.

Larus have assumed a deep water turbidite depositional setting with each depositional system being discrete and separate and RISC note that turbidite depositional systems have varied architecture and fabric. Larus's geological model for System 2 is a slope channel setting with lateral accretion and amalgamated channel bodies. RISC have focused on System 2 as the primary target for our analyses and valuation.

Larus have aggregated the prospect and leads into a number of geographical clusters. Cluster 1 is identified as having the best reservoir potential, there are 3 main prospects in this cluster. All these prospects have targets in the System 2 depositional environment.

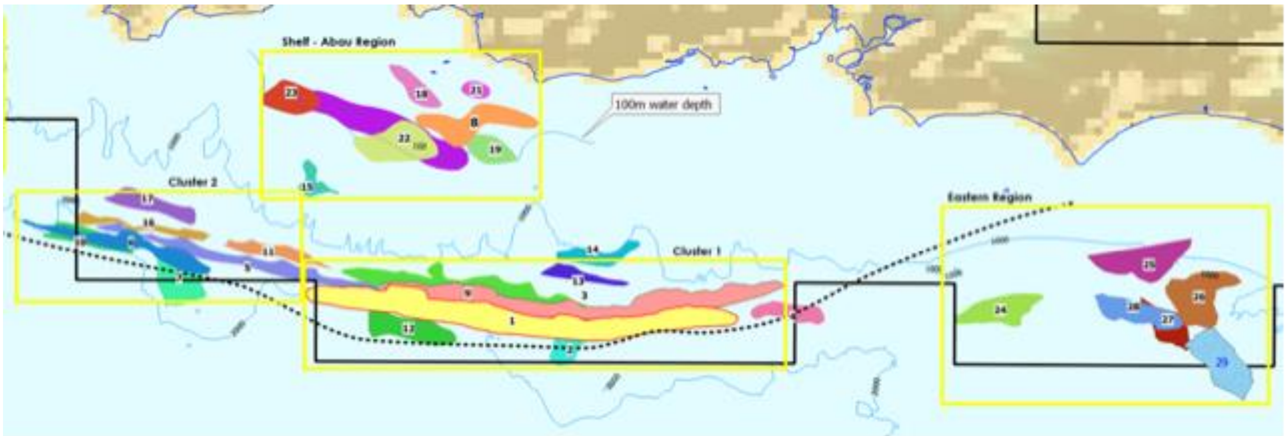

Figure 5-1: PPL 579 prospect location map

RISC consider the prospect and lead portfolio as immature, requiring further seismic (ideally 3D) to mature the portfolio and select a candidate for the drilling of an exploration well.

5.4. Hydrocarbon generation

With apparent structure mapped on 2D seismic in addition to the interpretation of reservoir depositional fairways, hydrocarbon generation and migration is considered the highest geological uncertainty. Very limited data is available to forecast hydrocarbon fluid type in the event of a discovery.

Larus has identified an onshore oil seep (Imilia oil seep) and has conducted geochemical analysis of the oil seep and geochemistry of fluid inclusions from the Imilia area (Figure 5-2). Offshore, geochemical data includes drop cores, heat flow measurements and dredge samples. The analysis indicates that the Imilia oil is light and of thermogenic origin most likely from source rock(s) in peak oil window.

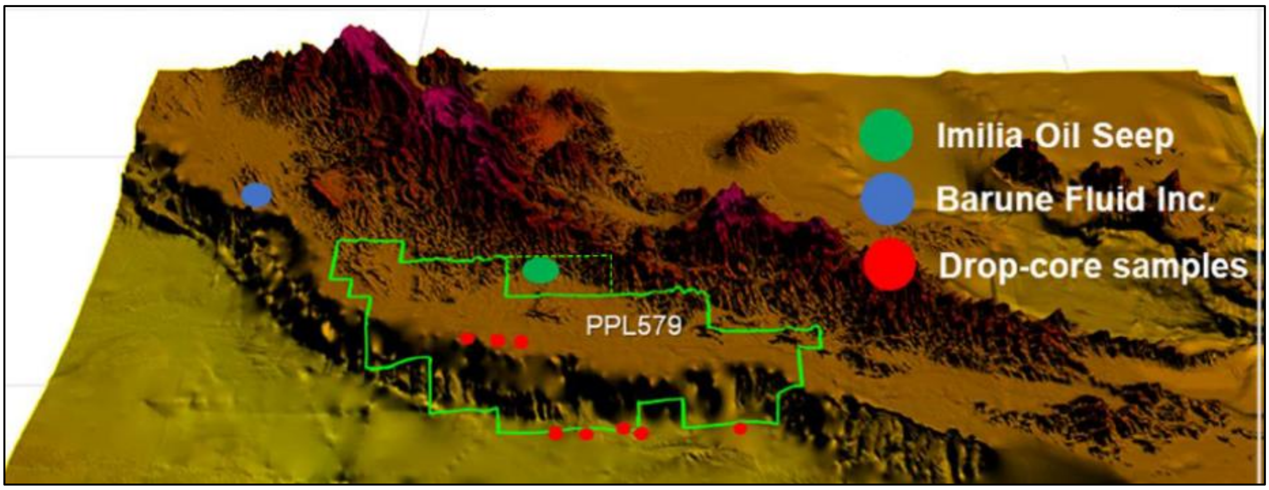

Figure 5-2: Location of Imilia seep and drop core samples

The source rock(s) have been typed to between Late Cretaceous and Paleogene of type II/III, or mixed from two separate source rocks, ie. Type II and Type III. The molecular composition of the oil indicates a source rock(s) with a tendency to produce mixed oil and gas, with a slight bias towards gas-condensates. The probability of biodegradation is considered to be low and the source may be active at present day.

The oil fluid inclusion recovered in the Barune area of Port Moresby contained similar characteristics to the Imilia Oil Seep data. The geochemistry of the drop core samples supports the presence of a working petroleum system.

6. Valuation

RISC has considered oil and gas industry accepted practices to determine Value, including comparable transactions, farm-in promotion factors, sunk costs and value of work program. Alternative valuation approaches have also been investigated to support the valuation are discussed below.

RISC has assessed a fair market value of Larus' net interest in the PPL 579 to be between AU$0.0 million and AU$12.6 million with a best estimate of AU$3.5 million (Table 6-1).

Table 6-1: PPL 579 valuation

PPL 579	Valuation (AU$ million)		
	Low	Best	High
100% Project	0.0	3.5	38.1
Net Larus	0.0	3.5	12.6
Valuation rationale	No value ascribed	Discounted sunk costs (seismic & work program)	Farminee seismic option and farmin factor (Larus retain 33%)

Notes to the table:

1. Low estimate assumes that the farm down attempts of the asset do not succeed.
2. Best estimate assumes partial consideration of sunk costs (seismic and work program, discounted at 5% / year).
3. High estimate assumes an incoming farminee carries Larus for 3D seismic ('seismic option'), exercises the option on participation in an exploration well with a 1.5:1 promotion factor on well, with Larus retaining 33% of the asset
4. Conversion rate of AU$1.4 to US$1 used.

RISC has used in its estimation of Value, the details of the sunk costs to date as provided by and incurred by Larus, the future costs associated with 3D seismic acquisition and an exploration well. Sunk costs and the range of future costs for the activities were provided by Larus.

RISC notes the possibility that the farminee following the 3D seismic acquisition does not exercise the option to participate in the drilling of an exploration well. This outcome would result in a valuation between the best and high estimates of Value and is therefore captured in the range of Value.

6.1. Assumptions

RISC has adopted the sunk costs and farm-in promotion factor methods for determining the best and high case fair market value of PPL 579 respectively.

The valuation method and analysis are detailed in Table 6-2.

Table 6-2: PPL 579 valuation analysis

Valuation Method & Analysis	Factor or Cost
Low Estimate – No value ascribed	
Implied project value	AU$0.0 million
Valuation net Larus	**AU$0.0 million**
Best Estimate – Sunk cost	
Sunk costs to date (all)	AU$14.1 million
Applicable and relevant sunk costs to date (seismic & work program)	AU$5.2 million
Discount applied to relevant sunk costs	~40% (5 % pa)
Implied project value	AU$3.5 million
Valuation net Larus	**AU$3.5 million**
High Estimate – Work Program, farm-in promote factor	
3D seismic acquisition (1,950 km2, offshore)	AU$16.7 million
Prospect exploration well cost	AU$42.9 million
Assumed farm-out equity	67 %
Value of carry on seismic (cost of seismic option)	AU$16.7 million
Farm-in promote factor (exploration well)	1.5 : 1
Farmin premium on exploration well (net to farminee)	AU$14.3 million
Farmin premium value on exploration well (gross)	AU$21.4 million
Implied project premium value (seismic option carry plus well premium) (gross)	AU$38.1 million
Implied project premium value (33% net to Larus after farmout)	AU$12.6 million
Valuation net Larus	**AU$12.6 million**
Notes to the table: 1. Costs are in AU$. Conversion rate of 0.7 AU$ per US$.	

RISC consider that the low case estimate of Value corresponds to an eventual lack of success of the farm down process of the asset. Larus have been pursuing a farm-out of the asset at various times since being awarded the license.

The asset is located in a frontier exploration basin where the potential number of interested parties can be considered limited. We also expect the vast majority of potential farminee candidates have reviewed the asset previously and have opted to not proceed with a farmin.

We note the end of the current license term in in March 2024, with a renewal/extension option to 2029. We therefore consider there is a realistic chance that Larus will be unable to farm-out the licence prior to the renewal/extension, in which case the licence has no value to Larus.

The sunk cost or work program method is commonly used for determining the value of an exploration permit. Larus has spent AU$14.1 million (US$10 million) on the permit since 2009. For the best estimate of Value, we have opted to select the sunk costs associated with seismic (acquisition, purchase or processing) and work program amounting to AU$5.2 million undiscounted.

For valuation purposes RISC has elected to discount the relevant past costs consisting of work program and seismic. The seismic costs account for the majority of the past costs and constitute primarily the cost of licensing multiclient seismic data processed and licensed by Larus over 10-years ago. Licensing that processed data today would likely be at a discount to that paid at the time. In addition, the seismic processing applied to the data licensed by Larus is likely to be superseded. Industry practise is to reacquire seismic data every 10-years, and reprocess every 5-years, therefore it is likely that recent reprocessing may be available for licensing. Industry guidance is to retain between 25% and 75% of relevant past costs for valuation purposes, summarised as follows:

Table 6-3 Guidelines for proportion of relevant historical expenditure to retain

Retained %	Property Characteristics
75%	Property with resources but no work performed for some years
50%	Property with sub economic resources but may have some potential in the future
25%	Inactive property with very little hope for development but cannot be written off completely

The exploration potential of PPL 579 does not map directly with any of these characteristics. In our opinion the potential of PPL 579 can be described as high risk, high reward. The licence does not contain (discovered) resources but in the event of a discovery there is a reasonable likelihood that the resources would have value i.e the permit has significant potential. Therefore in our opinion between 75% and 50% of relevant historical costs should be retained. We have elected to retain approximately 2/3 of the relevant past costs of AU$5.2 million. Given that the seismic costs were incurred 2010 – 2012 this is comparable to discounting the costs 5% pa.

For a high case determination of value, RISC has used the farm-in promotion factors method. In this scenario, it is assumed that a farminee will obtain 67 % participating equity in the asset in return for a free carry of Larus for 1,950 km2 of 3D seismic acquisition (estimated to cost AU$ 16.4 million gross), with an option to participate in the drilling of an exploration well (AU$ 42 million gross), with a promote factor then of 1.5:1.

This scenario is termed a ‘seismic option’ and is a common industry farmin approach where further seismic (typically 3D) is required to de-risk and mature the exploration objective(s) prior to an exploration drilling decision. In this scenario, incoming joint venture participants or farminee bear the cost of the seismic (AU$16.7m) in return for more favourable promote factors on an exploration well. The farminee can elect to participate in the drilling of the exploration well, or not, following the evaluation of the 3D seismic.

We have considered that in the seismic option scenario, with a 1.5 : 1 promote factor achieved on an exploration well. In this instance, the farminee would earn a 67% working interest in the license with Larus receiving a carry on its retained 33% working interest.

Promotes of 1.2 : 1 to 1.5 : 1 would be considered reasonable in RISC's opinion for a seismic option, whereas promote factors of up to 2 : 1 could be achieved without the seismic option.

Therefore in the case of a farmin on the terms outlined above the net value to Larus is:

0.33 * [(the value of the 3D carry) + (the value of the promote on the exploration well)]. Where:

Value of the 3D carry = cost of 3D = AU $16.7 million

Value of promote on the exploration well = well cost * (1.5-1) = 42.9 * 0.5 = AU $21.4 million

This assumes Larus is able to negotiate retaining 33% equity in the permit in return for being carried through the cost of the seismic and the exploration well.

6.1.1. Valuation alternatives

RISC has considered a series of exploration assets we consider comparable to PPL 579 which have transacted in recent years in order to provide a comparison to the high estimate of Value where the Value is based on a potential transaction. Those assets are listed in Table 6-4.

The drawn analogy with PPL 579 resides in the location of these assets in a frontier exploration setting, in conjunction with their exploration maturity versus farm down timing. Only offshore projects have been selected. One transaction which has occurred pre-2014 is also presented.

Transactions on assets considered analogous to PPL 579 occur mostly on a cash (past costs reimbursement) and promote (carry on exploration well) basis. Cash and a bonus payment can occur when the seller is fully divesting its position (therefore no well carry is required).

Cash considerations are typically below < AU$ 5 million and typically relate to a reimbursement of the seller's sunk costs. Firm carry relates to acquisition of new 2D or 3D seismic, targeting mature existing prospects in preparation of future exploration drilling. For larger blocks, new seismic acquisition would be restricted to the most prospective part(s) of the block. Value varies largely with the size of the survey to be acquired. This consideration type uses typically a range of farm-in promotion factors of 1:1 - 1.5:1.

When a seller retains an interest in the farm-out asset, contingent considerations are related to further exploration drilling. A contingent carry for exploration drilling typically have a range of farm-in promotion factors of 1:2 - 1.5:1. When the seller does not retain an interest in the block, the contingent consideration is typically a bonus related to commercialization milestones.

Table 6-4: Comparable transaction summary

Year	Buyer	Seller	Asset	Acquired Stake	Frontier Setting	Transaction Value (Net Seller, AU$ million)	
						Cash + Firm Carry	Contingent
Pre- 2014							
2013	Tullow	Pancontinental	PEL 37	65% + op	Deepwater Namibia	**18.0**	35.7 (carry)
Post- 2014							
2019	Tullow	Calima	PEL	56% + op	Deepwater	**2.9**	14 (bonus)

			90		Namibia		
2020	Conoco	3D Oil	T/49P	80% + op	Shallow water Australia	**8.4**	8.4 (carry)
2019	OPIC	Lion	East Seram PSC	40%	Shallow water Indonesia	**6.3**	8.6 (carry)

Notes to the table:

1. Deepwater means water depths that require a floating (semi-submersible) drilling rig; shallow water means water depths in which a Jack-up rig can operate
2. All transaction are on cash and carry basis, with the exception of PEL 90 where Calima divested fully its interests in the block and contingent considerations are related to commercialization of discovered resources a capped. Contingent considerations for East Seram PSC assumes 2-exploration wells.
3. Costs are in AU$. Conversion rate of AU$1.4 to US$1 used.

More recent transactions support a total consideration inclusive of cash and a firm carry, along with contingent (carry or bonus) of AU$ 15 – 17 million. Excluding contingent considerations, this results in a range AU$ 6 – 9 million when the seller retains an interest.

We would argue that the consideration is driven primarily by an allocated budget for new acquisition, typically in the range of AU$ 5 - 10 million. Contingent considerations being subject to additional budget allocations.

As seen in Table 6-4, the comparable transaction values are aligned with the high estimate of Value of PPL 579 being AU$12.6 million net to Larus.

7. Declarations

7.1. Terms of engagement

This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

7.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. We have completed over 2,000 assignments in 70+ countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been peer reviewed by Mr Adam Craig who is an employee of RISC. Mr Craig is a highly experienced Geoscientist and Manager, with over 30-years' experience in the upstream oil & gas sector working for small and mid-size independents, as well as NOC related entities. He is a member and Certified Practising Geologist (#6446) of the AAPG. Adam is also a member of PESA (2021/22 WA Branch President) and a Fellow of the Geological Society. He holds BSc in Geology from Curtin University, Western Australia and is a qualified petroleum reserves and resources evaluator (QPRRE) as defined by ASX listing rules.

7.3. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) 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), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

This Report has been prepared in accordance with the Australian Securities and Investment Commission (ASIC) Regulatory Guides 111 and 112.

7.4. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, 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/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, 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, encumbrances or regulations that apply to these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

7.5. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Larus and Hall Chadwick and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Hall Chadwick, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Larus, Hall Chadwick or in any of the properties described herein.

7.6. Copyright

This document is protected by copyright laws. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

7.7. Consent

RISC has consented to this report, in the form and context in which it appears, being included, in its entirety, in the Notice of Meeting. Neither the whole not any part of this report nor any reference to it may be included or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

8. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (10^9) cubic feet
BCM	Billion (10^9) cubic metres
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
DEG	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
EIA	US Energy Information Administration

Term	Definition
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)

Term	Definition
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty 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. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration

Term	Definition
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	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 categorised 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.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	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), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil