
# Repositioned for Growth

Autumn 2019

# Disclaimer

All oil and natural gas reserves and resources information, including estimated production rates, contained in this presentation have, unless otherwise stated, been prepared and presented in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the Canadian Oil and Gas Evaluation ("**COGE**") Handbook.

TAG Oil Ltd. ("TAG", "TAG Oil" or the "Company) has adopted the standard of six thousand cubic feet of gas to equal one barrel of oil when converting natural gas to "boe," which may be misleading, particularly if used in isolation. A boe conversion ratio of 6Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**Reserves Estimates**
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:
•at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated *proved* reserves;
•at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated *proved* plus *probable* reserves; and
•at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated *proved* plus *probable* plus *possible* reserves.

The reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves or resources will be recovered. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Where discussed herein "NPV 10%" represents the net present value (net of capital expenditures) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and initial production rate, less internal estimates of operating costs and royalties. It should not be assumed that the future net revenues estimated by TAG's independent reserve evaluators represent the fair market value of the reserves, nor should it be assumed that TAG's internally estimated value of its undeveloped land holdings or any estimates referred to herein from third parties represent the fair market value of the lands

**Resource Estimates**
Unless otherwise noted, the resource estimates in this presentation are a best case estimate internally by TAG professionals who are non-independent, qualified reserves evaluators in accordance with NI 51-101 and COGE Handbook, with effective dates of March 31, 2018. The recovery and resource estimates provided in this presentation, the preliminary prospectus and in the documents incorporated by reference herein are estimates only. Actual Contingent Resources and Prospective Resources (and any volumes that may be reclassified as reserves) and future production from such Contingent Resources and Prospective Recourses may be greater than or less than the estimates provided herein.

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.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the resources.

Exploration for hydrocarbons is a speculative venture necessarily involving substantial risk. The Company's future success in exploiting and increasing its current reserve base will depend on its ability to develop its current properties and on its ability to discover and acquire properties or prospects that are capable of commercial production. However, there is no assurance that the Company's future exploration and development efforts will result in the discovery or development of additional commercial accumulations of oil and natural gas. In addition, even if further hydrocarbons are discovered, the costs of extracting and delivering the hydrocarbons to market and variations in the market price may render uneconomic any discovered deposit. Geological conditions are variable and unpredictable. Even if production is commenced from a well, the quantity of hydrocarbons produced inevitably will decline over time, and production may be adversely affected or may have to be terminated altogether if the Company encounters unforeseen geological conditions. The Company is subject to uncertainties related to the proximity of any reserves that it may discover to pipelines and processing facilities. It expects that its operational costs will increase proportionally to the remoteness of, and any restrictions on access to, the properties on which any such reserves may be found. Adverse climatic conditions at such properties may also hinder the Company's ability to carry on exploration or production activities continuously throughout any given year.

"Best estimate" is considered to be the best estimate of the quantity of the prospective resource that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

# Disclaimer (continued)

**Resource Estimates (continued)**
The significant positive factors that are relevant to the resource estimates are:
•Proven production in close proximity;
•Proven commercial quality reservoirs in close proximity;
•Oil and gas shows while drilling wells; and
•Calculated hydrocarbon pay intervals from open hole logs.

The significant negative factors that are relevant to the resource estimates are:
•Tectonically complex geology could compromise seal potential; and
•Seismic attribute mapping can be indicative but not certain in identifying proven resource

**Non-GAAP Measures in this Presentation**
References to "netbacks" in this presentation are references to "operating netback", a non-GAAP measure. Operating netback is the operating margin that the Company receives from each barrel of oil equivalent sold. Operating netback is exclusive of electricity revenue and costs and denotes oil and gas revenue on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses. Please see "*Summary of Quarterly Information – Oil and Gas Operating Netback ($/boe)*" and "*non-GAAP measures*" in the Company's Management's Discussion and Analysis, dated November 14, 2018, for the three months ended June 30, 2018 for more information regarding the calculation of the Company's operating netback.

**Analogous Information**
Certain information in this document may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas with similar geological characteristics to the lands held by the Company. Such information is derived from a variety of publicly available information from government sources, regulatory agencies, public databases or other industry participants (as at the date stated therein) that the Company believes are predominantly independent in nature. The Company believes this information is relevant as it helps to define the reservoir characteristics in which the Company may hold an interest. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and in accordance with the COGE Handbook. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data and economics information for the lands held by the Company will be similar to the information presented therein. The reader is cautioned that the data relied upon by the Company may be in error and/or may not be analogous to the Company's land holdings.

**Forward-Looking Statements**
Statements contained in this document that are not historical facts are forward-looking statements that involve various risks and uncertainty affecting the business of TAG. Such statements can be generally, but not always, identified by words such as "expects", "plans", "anticipates", "intends", "estimates", "forecasts", "schedules", "prepares", "potential" and similar expressions, or that events or conditions "will", "would", "may", "could" or "should" occur. All estimates and statements with respect to TAG"s operations are forward-looking statements under applicable securities laws and necessarily involve risks and uncertainties including, without limitation: risks associated with oil and gas exploration, development, exploitation and production, geological risks, marketing and transportation, availability of adequate funding, volatility of commodity prices, imprecision of resource estimates, environmental risks, competition from other producers, and changes in the regulatory and taxation environment. Actual results may vary materially from the information provided in this document, and there is no representation by TAG Oil that the actual results realized in the future will be the same in whole or in part as those presented herein.

Forward-looking statements relating to TAG Oil's exploration and development of its oil and gas properties including with respect to completion of its drilling programs involve risks and uncertainties including, without limitation: regulatory approval, equipment availability, weather, risks associated with establishment of additional production of oil and gas in accordance with TAG Oil's expectations at its oil and gas properties, well performance, drilling results, successful completion of new infrastructure at its oil and gas properties, successful optimization, the increase of cash flow from new production, achievement of expected growth, successful results of operations, performance results, prospects and evaluation results.

Other factors that could cause actual results to differ from those contained in the forward-looking statements are also set forth in filings that TAG and its independent evaluator have made, including TAG's most recently filed *Statement of Reserves Data and Other Oil and Gas Information*, prepared by independent qualified reserves evaluators, ERC Equipoise Limited, with an effective date of March 31, 2019 (the "**ERC Report**"). The ERC Report and additional reports filed in Canada pursuant to NI 51-101 can be found under TAG's SEDAR profile at www.sedar.com. TAG undertakes no obligation, except as otherwise required by law, to update these forward-looking statements in the event that management's beliefs, estimates or opinions, or other factors change..

**Abbreviations**

| Crude Oil and Natural Gas Liquids | | Natural Gas | |
|---|---|---|---|
| bbl | barrel(s) | Mcf | thousand cubic feet |
| bbl/d | barrels per day | MMcf | million cubic feet |
| Mbbl | thousand barrels | Mcf/d | thousand cubic feet per day |
| MMbbl | million barrels | MMcf/d | million cubic feet per day |
| boe | barrel of oil equivalent | Bcf | billion cubic feet |
| boe/d | barrel or barrels of oil equivalent per day | NGL | natural gas liquids |
| MMboe | million barrel of oil equivalent | | |

# Highlights

- On September 25th, 2019, TAG announced the closing of the sale of its New Zealand assets to Tamarind
  - c. C$41 M cash balance on closing
  - c. C$0.50 / share
- Opportune time to exit New Zealand due to a combination of factors
  - strong commodity price: effective date is October 1st, and oil prices peaked in most recent cycle on October 3rd
  - mature assets with limited further exploration growth potential in New Zealand
  - shift in government has led to reduced opportunities to acquire new exploration acreage
- Management looking at all options to maximize value for shareholders
  - mergers
  - acquisitions
  - corporate sale
  - return of capital
- Normal Course Issuer Bid (“NCIB”) in place which allows TAG to buy back up to 6.4 M shares

# Foundation for Success

**Working Capital[1]**

- ~C$41 million in cash with no debt
- ~C$0.50 / share in cash
- G&A substantially covered by royalty and interest payments

**Capital Structure[1]**

- 85.4 million shares o/s; 89.5 million fully diluted

**2.5% Royalty on Gross Revenue**

- Current production ~1,300 boepd
- ~75% oil
- Applies to all current and future production in New Zealand
- Supplejack development online in Q1 2020 with over 500 boe/d of gas

**Up to US$4.5 M in milestone payments**

- Payments based on certain operational hurdles being met
- Estimated payout over two to four years

**Over 275,000 acres in Australia**

- Three blocks 100% WI blocks in the Surat Basin
- Prospective for both oil and natural gas
- Politically stable, fiscally attractive, under-drilled, strong market, services readily available

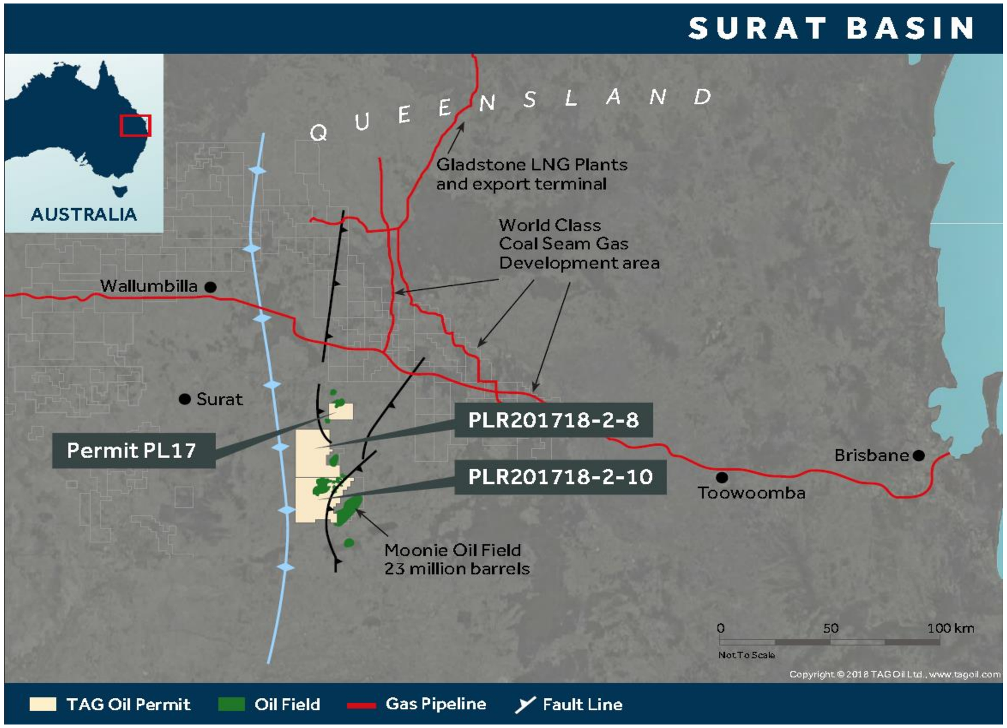
[1] *As at FQ2/19 (September 30, 2018) and adjusted for cash payment of US$30.5 M upon closing sale of NZ properties;*

# Experienced Leadership Team

| | |
|---|---|
| **Toby Pierce**<br>Chief Executive Officer, BSc, MBA | Experienced natural resource executive with expertise in operations, capital markets, investment banking and M&A; Geologist |
| **Barry MacNeil**<br>Chief Financial Officer, CPA | 20 years of financial and operational experience in public and private practice, including mining, forestry and oil & gas |
| **Gavin Wilson**<br>Director, BA | Investment Manager for Meridian Group of Companies, a private investment Company. Over 25 years of oil & gas investment experience |
| **Keith Hill**<br>Director, BSc, MSc, MBA | CEO of Africa Oil Corp. (AOI), with more than 30 years of leadership experience in the oil and gas industry; Geologist |
| **David Bennett**<br>Director, MSc, PhD | More than 40 years of exploration, technical, operational, and corporate experience in New Zealand and throughout Australasia; Geophysicist |
| **Brad Holland**<br>Director, C. Eng | 35 years of experience in the oil and gas industry, 18 years as Senior Project Engineer for Saudi Aramco |
| **Peter Loretto**<br>Director, P. Eng | 30 years of investment banking and public company experience. Founder of Trans-Orient Petroleum Ltd. |
| **Ken Vidalin**<br>Director, P. Eng | The founder of global corporations Methanex and Acetex, with more than 20 years of board experience |

# Australia

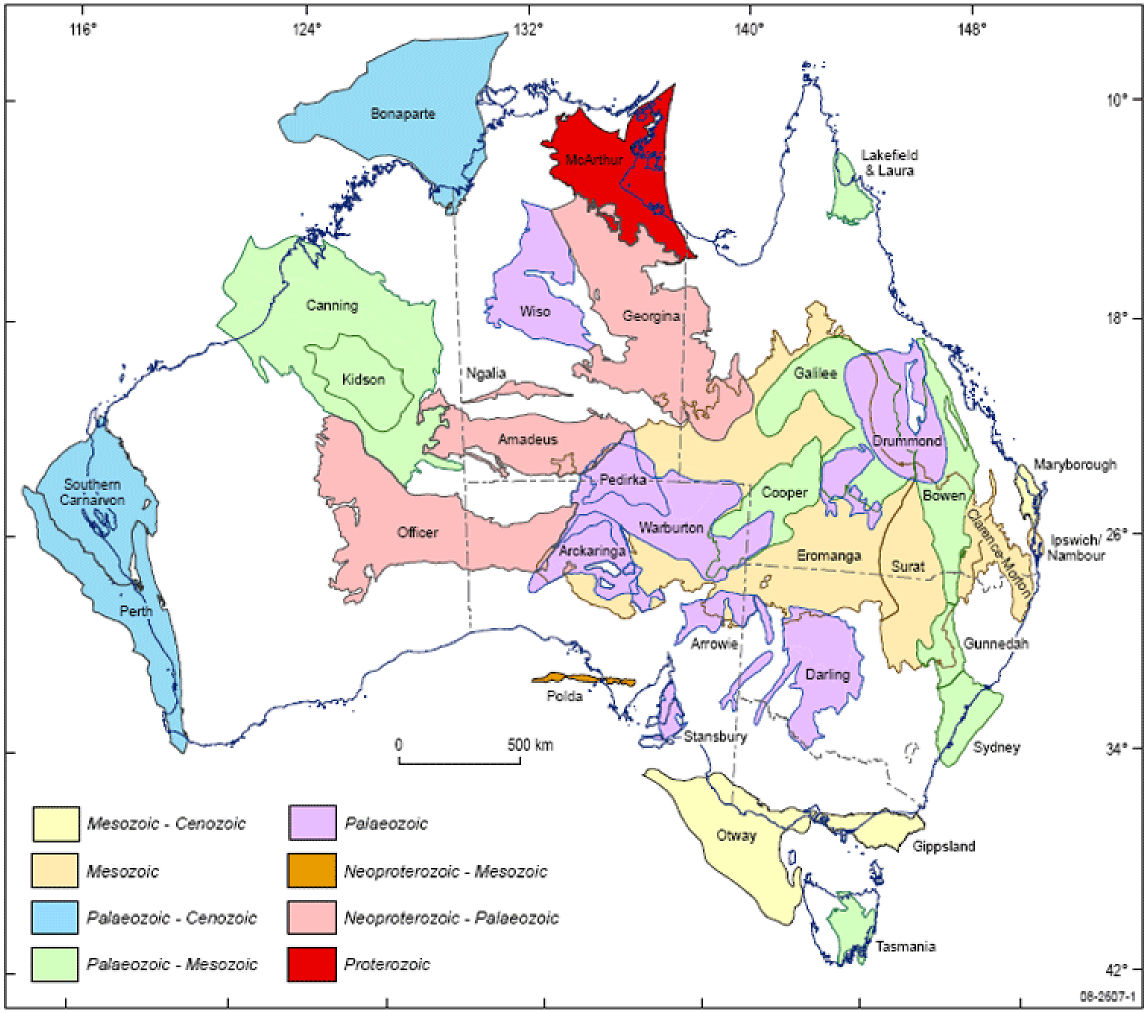
- Post closing the sale of its New Zealand assets, TAG will have three blocks in the Surat Basin of Australia
- PL 17
  - acquired in January 2017
  - covers 104 km$^2$ (25,700 acres)
  - two discoveries on block with small amount of light oil production (10 – 15 b/d)
  - seismic acquired summer of 2017
- Two blocks awarded in the March 2018 call for tenders
  - cover 1,046 km$^2$ (258,472 acres)
  - formally granted December 2018
  - both licences have six year terms with a well commitment in year four
- Total commitments in Australia of c. $5 M over the next four years
  - opportunities to farm out interest and bring in 3rd party capital
- Focus will be on conventional oil and gas



# Why Queensland Australia

- High prices for oil and gas
  - oil is usually sold at Brent price or better
  - gas prices range from A$8-12/GJ and tied to Asian LNG prices
- Six prolific petroleum basins in Queensland alone
  - Surat, Bowen, Cooper, Eromanga, Gailee, Drummond
- Liquid transaction market for assets
- Low taxes
  - Corporate tax 30%
  - Queensland royalty 10%
- Politically stable
  - Federal and the Queensland government have partially funded exploration or development work get more gas to the domestic gas market
- Large service sector
- Skilled labor

## Australia Onshore Sedimentary Basins

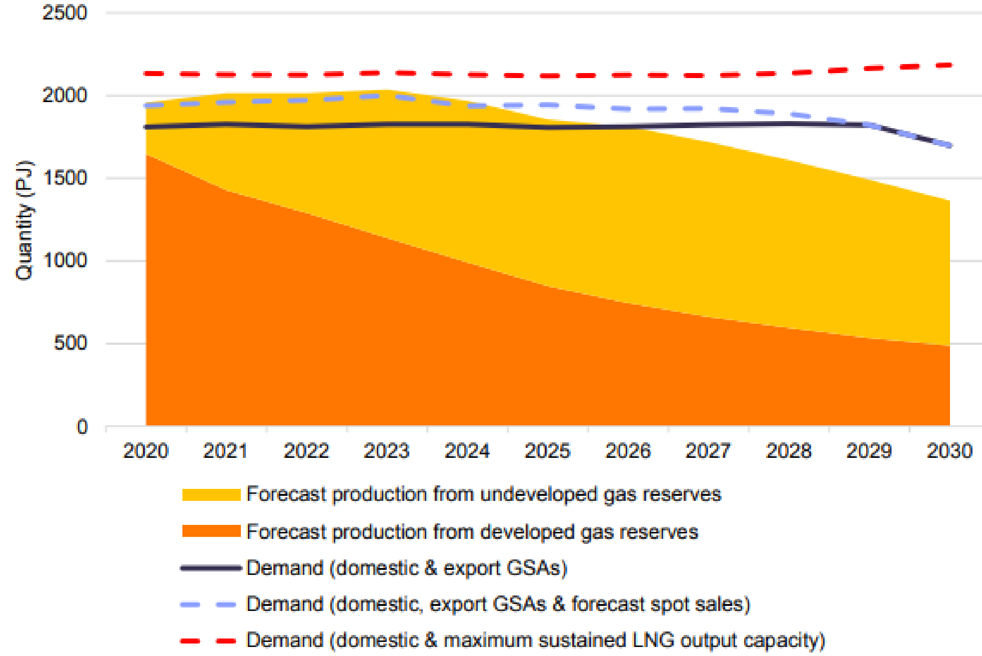



Source: Australian Government *© Geoscience Australia* (http://www.ga.gov.au/about/projects/resources/onshore-petroleum)

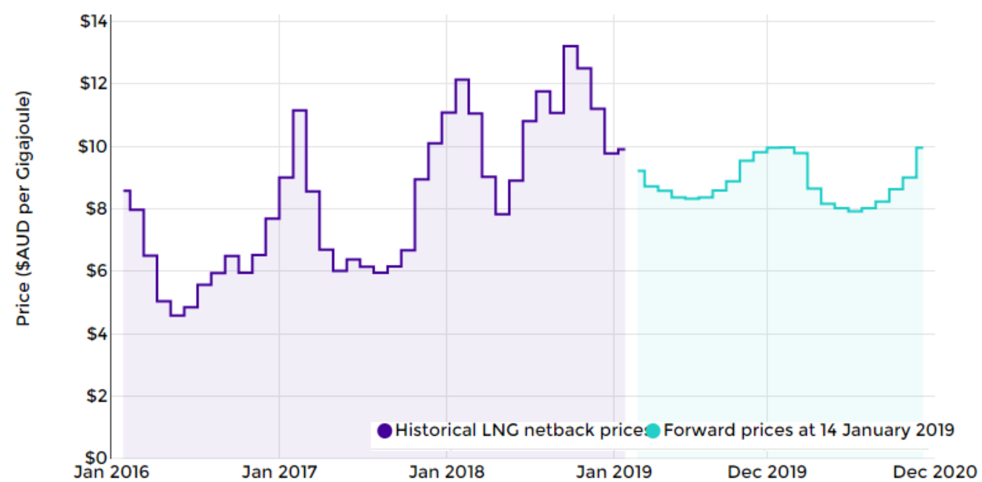
# Strong Eastern Australia Gas Market

- Strong domestic gas price A$8-12/GJ forecasted going forward
- Three LNG export terminals north of Brisbane with a combined maximum capacity of 1,455 PJ per annum have linked the domestic East Coast gas price to regional LNG prices
  - currently below capacity and searching for more product
- With LNG demand looking outpace supply going in a few years time domestic gas price could potentially increase further

**Forecast gas supply (incl. NT) and demand on East Coast**




**LNG netback price at the Wallumbilla Gas Supply Hub**



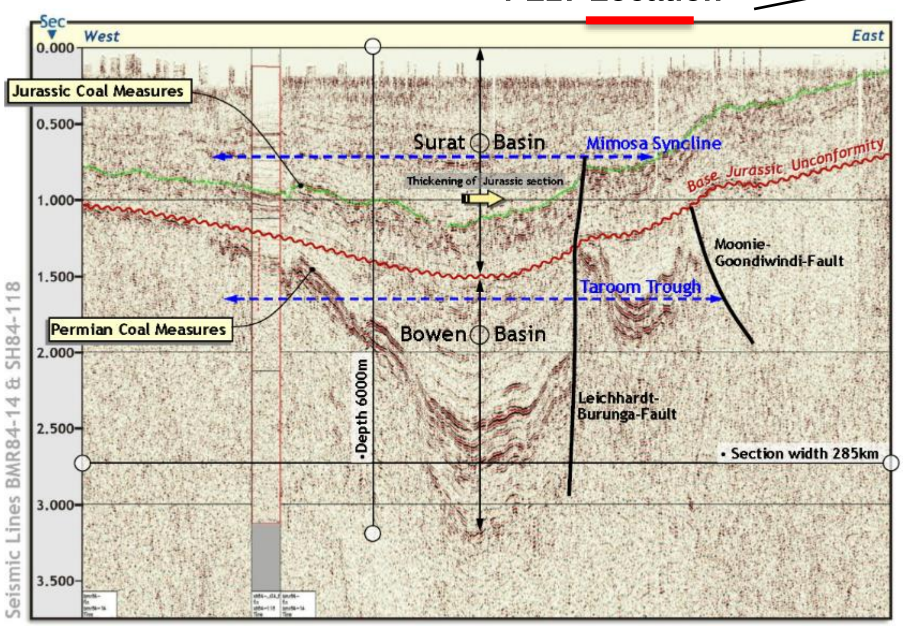



Source: ACCC Gas inquiry 2017 -2020 LNG netback price, January 16 2019

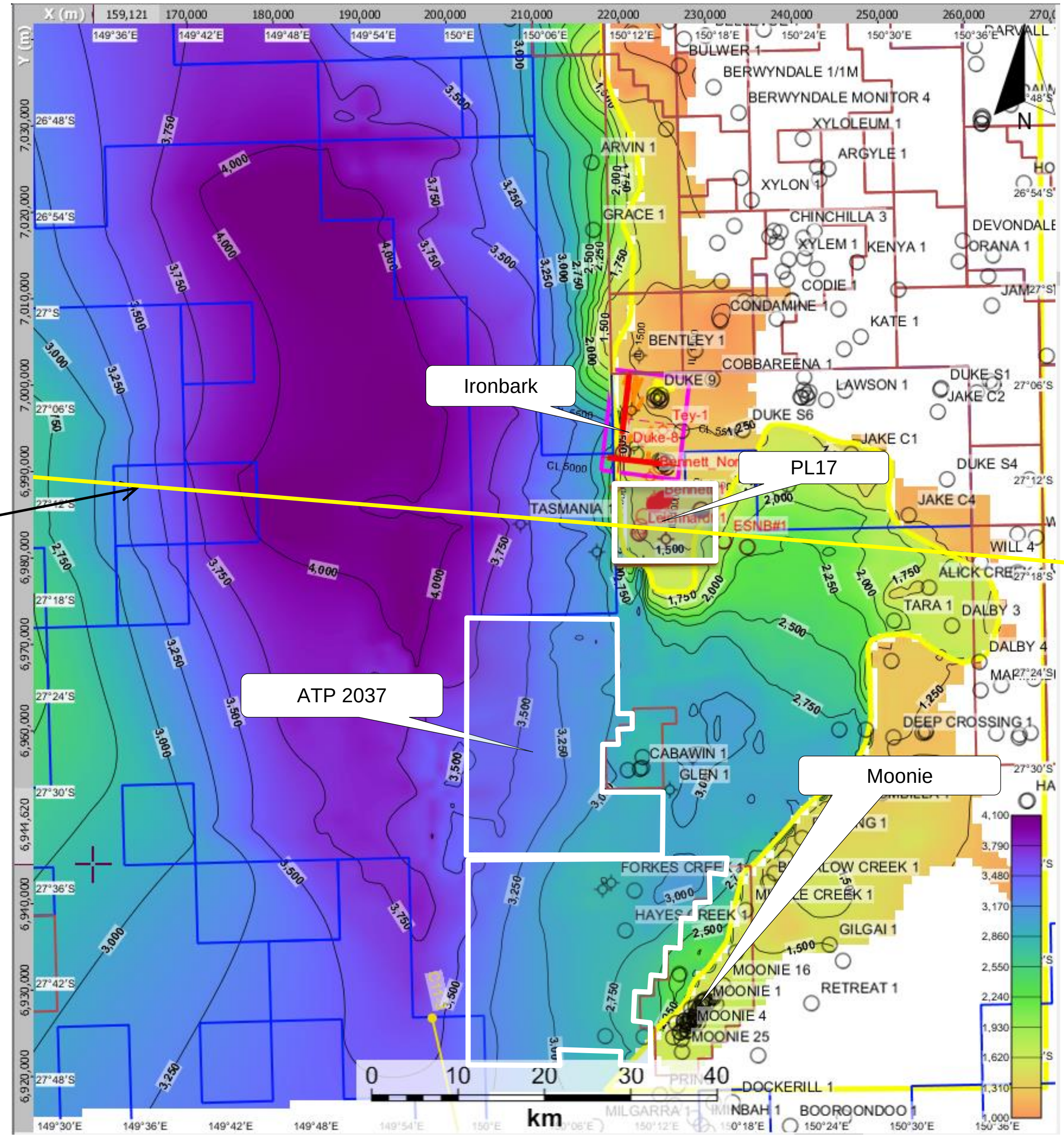
# Australia – Regional Setting

- PL 17 lies on the Undulla Nose, on the eastern side of the Taroom Trough, in an excellent location to receive charge from the Taroom Trough to the west.

**PL17 Location**



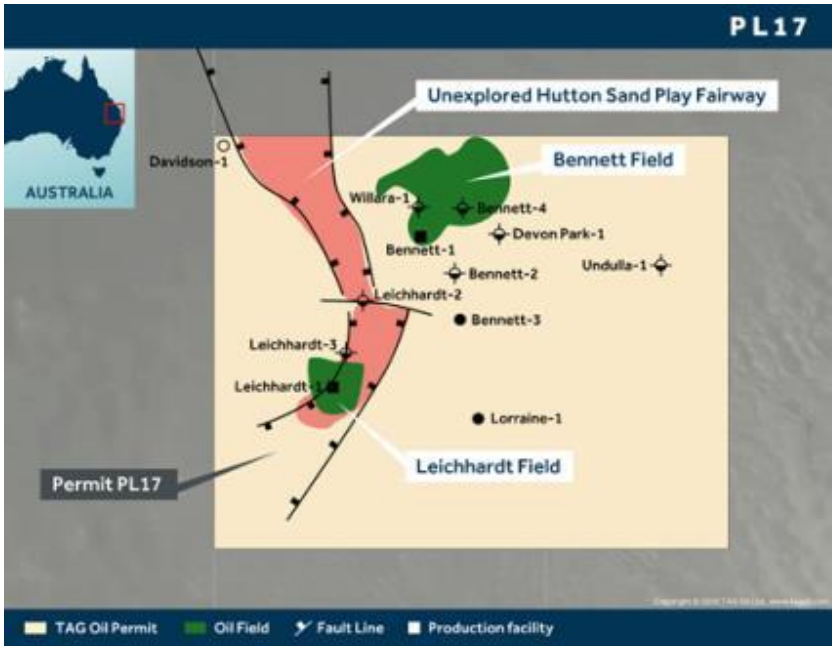

Approximate location of regional seismic line shown by yellow line on map to the right

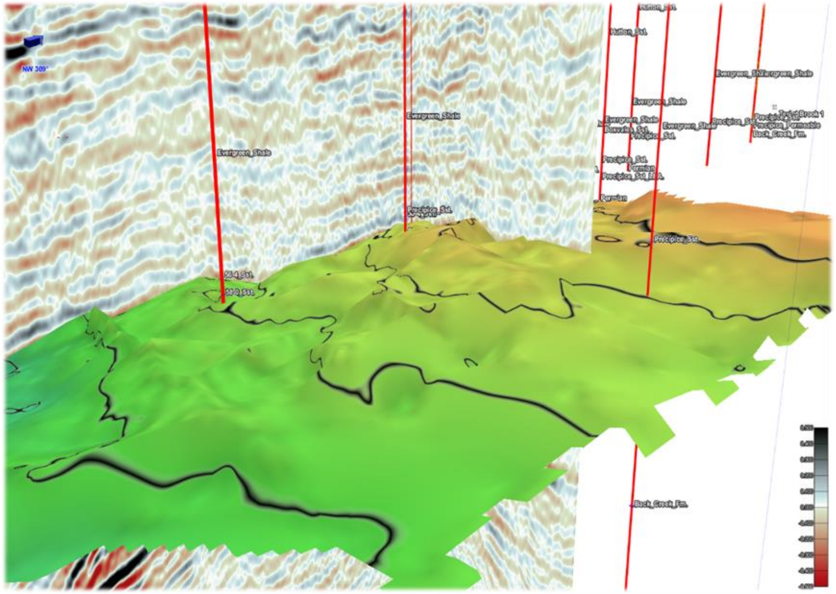



Near Top Permian TWT Structure Contour Map

# PL 17 – Production licence in Eastern Surat Basin

- PL 17 is located in the Surat Basin of Australia, covering an area of 104 km$^2$ (25,700 acres)
  - ~20 km from the Moonie Oil Field which has produced 27 mmb to date
- Two existing discoveries on the block which have produced on and off for ~50 years
  - Bennett Field: 160 Mbbl produced to date
    - current production from two wells of ~15 bbl/d of light oil
  - Leichhardt Field: 150 Mbbl produced to date
    - currently shut-in; awaiting workover
- Permian oil play is the primary conventional opportunity
  - 3D seismic acquired over block in summer of 2017 will be used to define the play and identify drilling opportunities
- Purchase cost is A$2,500,000
  - fully paid



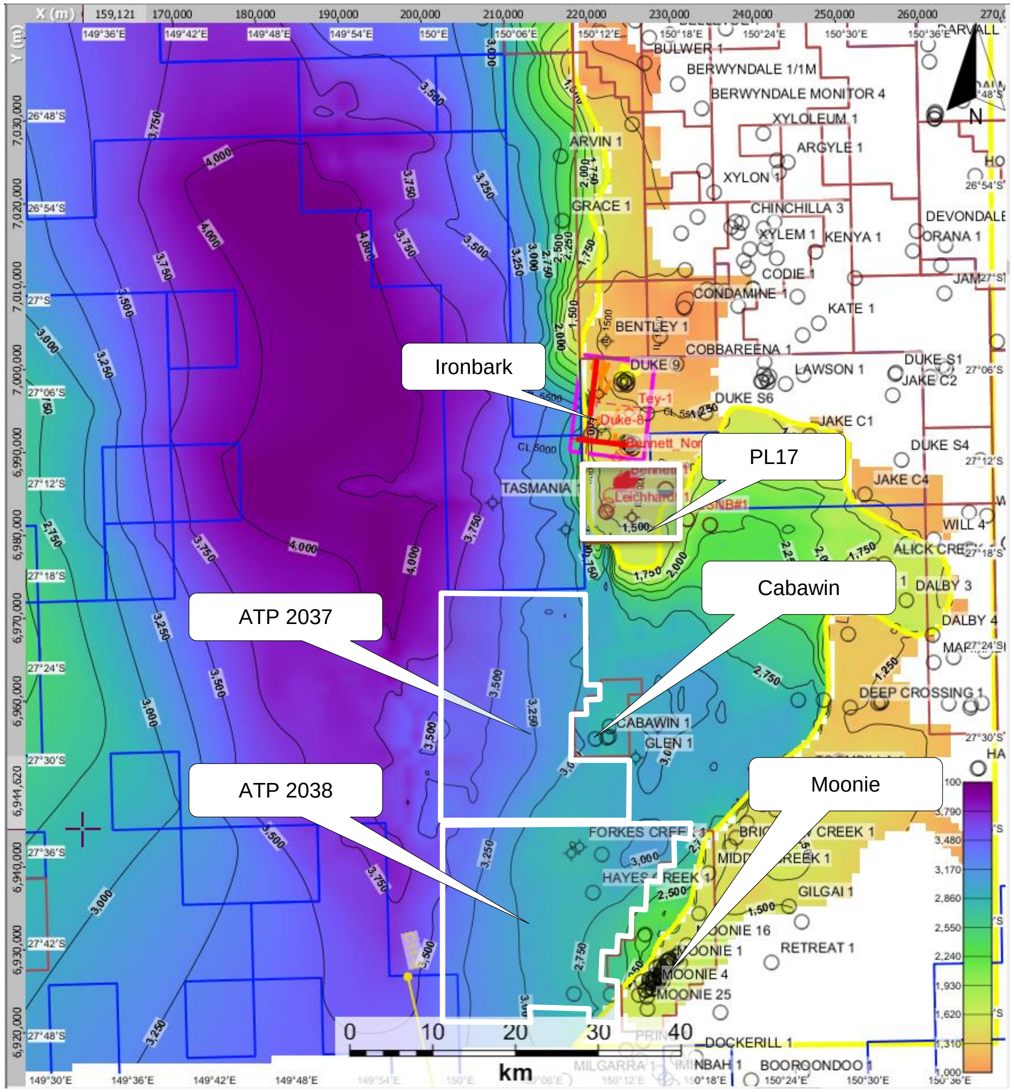



*Source: TAG Oil*

# ATP 2017 (Rocky Dam) and 2038 (Kingston) Location

- ATP's 2037 and 2038 were awarded to TAG on 1 January, 2019, following the 201718 Acreage Release
- TAG has 100% equity and Operatorship of these permits

## Near Top Permian TWT Structure Contour Map



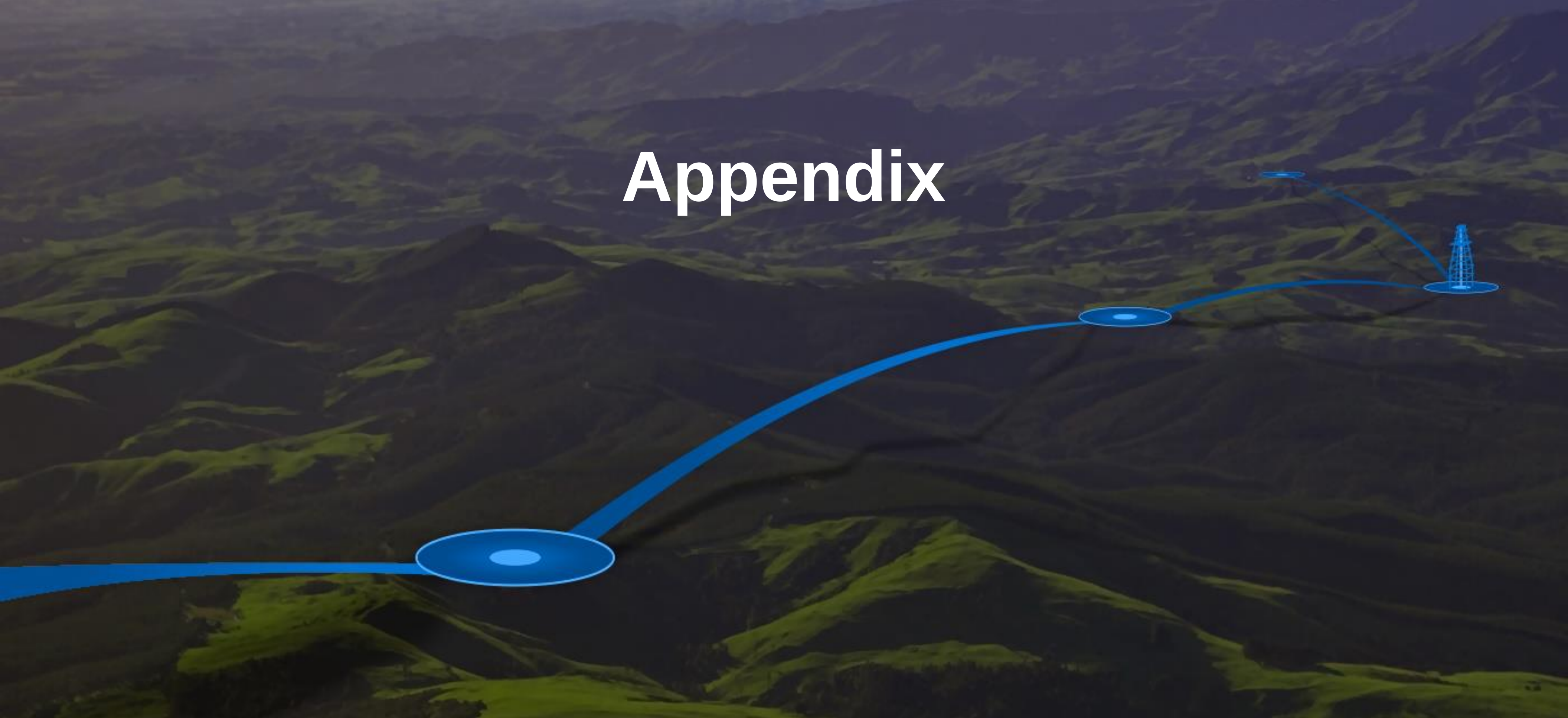
# Use of funds

- TAG is speaking to shareholders and getting their feedback on the preferred use of the cash proceeds from the sale of New Zealand
  - final decision will be based on what the majority of shareholders want
- All options are on the table, including, but not limited to:
  - Organic growth in Australia
    - upcoming licensing round in Queensland
    - enter other basins outside of Bowen / Surat
  - Corporate activity
    - asset acquisitions in Australia, and potentially elsewhere
    - corporate acquisitions / M&A
    - TAG as RTO vehicle
    - corporate restructuring into two or more entities
- Normal Course Issuer Bid (NCIB) share buy-back announced January 29, 2019
  - TAG can purchase up to 6,441,258 over the next year (up to 10% of the public float)
- TAG will continue to operate its Australia business as normal while reviewing options

# Why TAG Oil?

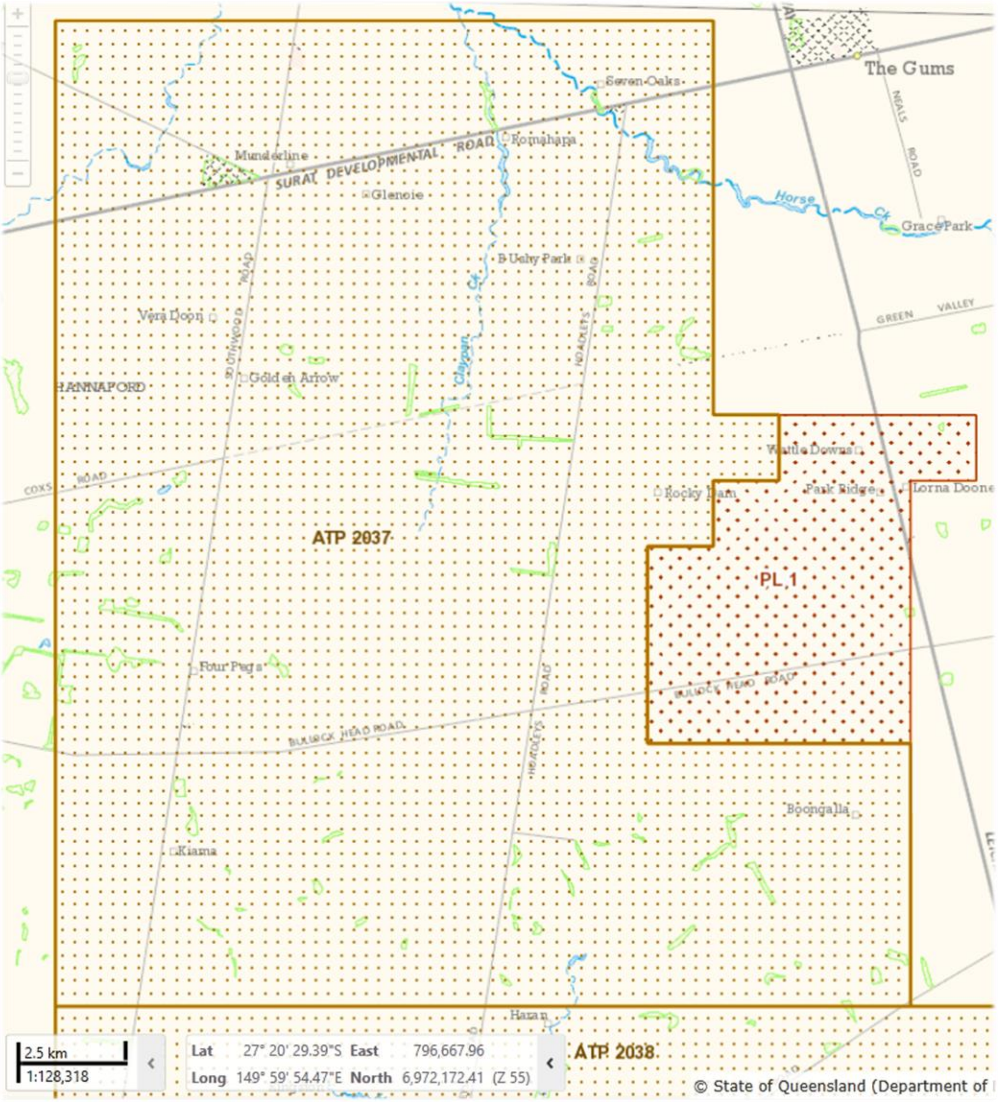
- Experienced exploration and operations team
- Positioned to grow at current and higher oil prices
- Long life production with potential resources upside
- Strategic holdings in stable, secure counry with very good fiscal terms
- Low cost, high netback premium Brent oil and high value gas producer
- Strong balance sheet and no debt
- High working interest and operatorship of all assets → high margins on production

# Appendix



# ATP 2037 – Permit Details

- Working interest: 100%
- Area: 487 km$^2$
- Permit expiry date: December 31, 2024
- Permit under 2004 Act
- Work program: See next slide
- Native title: Not negotiated
  - A very small part of the tenure has native title on it estimate to be about 1%, shown in grey on the map
- Environmentally sensitive land: Yes, shown in green on the map

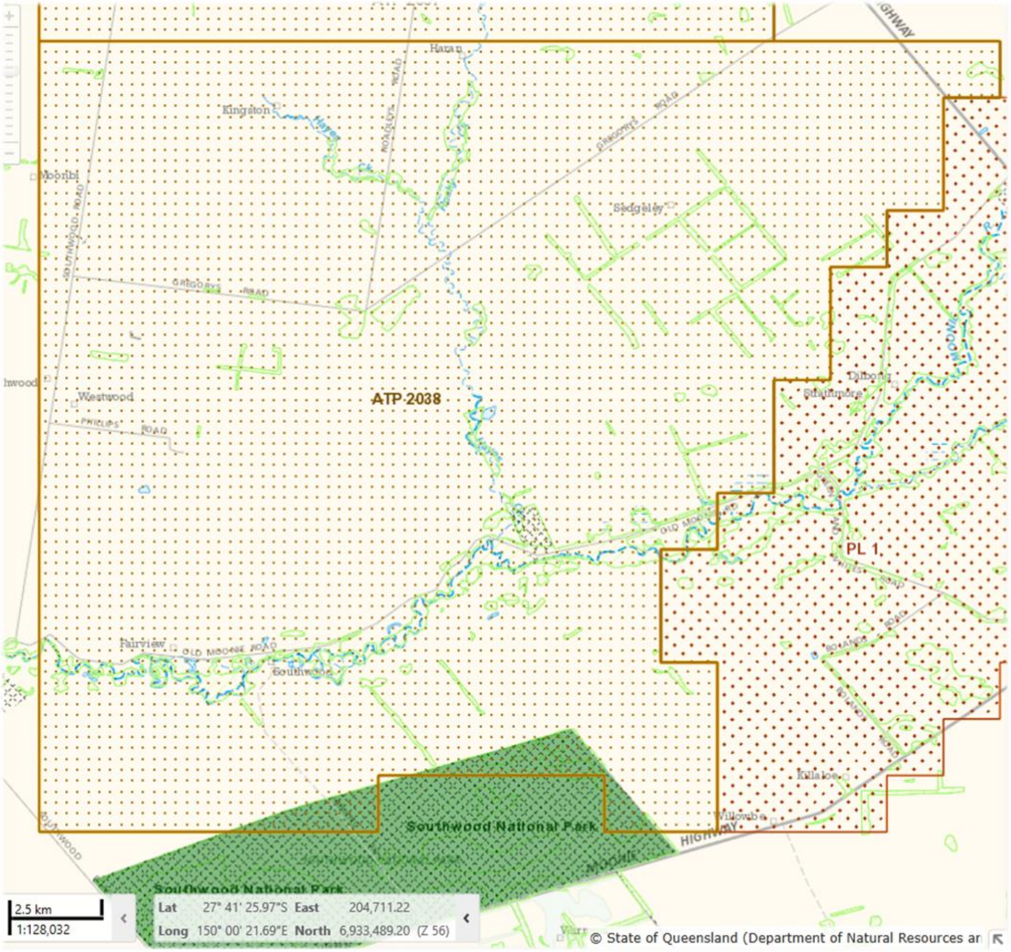


# ATP 2037 – Work Program

- Year 1
  - Reprocess 127 km of 2D. Currently being reprocessed by Earth Signal Processing in Calgary.
  - Reprocess 32 $km^2$ of 3D. Currently being reprocessed by Earth Signal Processing in Calgary.
  - Airborne Transient Electromagnetic Survey. Completed. Flown over ATP 2037, 2038, PL17, Cabawin & Moonie
  - G&G studies. Quote on petrophysical interpretation of A$20,000 for both ATPs
- Year 2
  - Finalise 2D and 3D reprocessing
  - G&G studies
  - Shoot 20km 2D seismic
- Year 3
  - G&G studies
- Year 4
  - Drill one well to assess the complete section of the upper Precipice, Evergreen and Hutton formations in the Surat Basin OR including the Kianga formation in the Bowen Basin
  - Preparation for seismic acquisition in the next period

# ATP 2038 – Permit Details

- Working interest: 100%
- Area: 559 km$^2$
- Permit expiry date: December 31, 2024
- Permit under 2004 Act
- Work program: See next slide
- Native title: Not negotiated
  - A very small part of the tenure has native title on it estimate to be about 1%, shown in grey on the map
- Environmentally sensitive land: Yes, shown in green on the map



# ATP 2038 – Work Program

- Year 1
  - Reprocess 253 km of 2D. Currently being reprocessed by Earth Signal Processing in Calgary.
  - Reprocess 70 $km^2$ of 3D. Currently being reprocessed by Earth Signal Processing in Calgary.
  - Airborne Transient Electromagnetic Survey. Completed. Flown over ATP 2037, 2038, PL17, Cabawin & Moonie
  - G&G studies. Quote on petrophysical interpretation of A$20,000 for both ATPs
- Year 2
  - Finalise 2D and 3D reprocessing
  - G&G studies
  - Shoot 30km 2D seismic
- Year 3
  - G&G studies
- Year 4
  - Drill one well to assess the complete section of the upper Precipice, Evergreen and Hutton formations in the Surat Basin OR including the Kianga formation in the Bowen Basin
  - Preparation for seismic acquisition in the next period

# New Zealand interest

Following the sale of its New Zealand assets, TAG will have the following exposure to New Zealand:

- 2.5% gross overriding royalty on gross sales revenues from all assets sold
  - approximately C$750k based on current baseline production forecast and commodity prices
- US$5 million in event specific payments from any combination of:
  - $1 M Supplejack Permit: Upon grant of mining permit (**$500 k – achieved and payable at closing**) and upon first production of 1 bcfe ($500 k)
  - $1 M Puka Permit: Upon grant of a mining permit ($500 k) and upon first production of 100 mboe ($500 k)
  - $2 M Cardiff: Upon booking of 26 bcfe of reserves ($1 M) and upon production of first 5 bcfe ($1 M)
  - $2 M Cheal & Cheal East: Upon production of 650 mboe ($1 M) and 1.5 mmboe ($1 M)
  - $1 M Waitoriki: Upon grant of a mining permit ($1 M)



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