

QUARTERLY REPORT

For the period ended 31 December 2024

31 January 2025



Main features

- Favourable production response from Odin-1 to initial scale management intervention
- Odin-2 commences production
- Sales revenue of \$1.5 million up 105%
- Production of 0.12 PJ_e, up 90% from 0.06 PJ_e
- Closing cash of \$2.2 million
- Vintage Energy – Galilee Energy merger proposal terminated

Managing Director's comment

"It is pleasing to report increased production and sales revenue, albeit in a quarter of mixed results. On the positive side, the performance of Odin-1 following the confirmation and initial treatment of scale accumulation demonstrated the upside potential from management of this issue more broadly in the southern flank. Moreover, our actual gas production was undoubtedly higher than reported due to the scale impact on metering. Odin-2's performance thus far has been surprising and disappointing and is to be investigated further, particularly for the scale accumulation which affected Odin-1. Should it be similarly affected, there is a pathway for performance improvement.

Cash outflow improved on the previous quarter due to higher gas sales and ongoing savings in corporate and administration costs."

Key figures	3 months to 31 Dec '24	Prior Qtr Sept '24	Qtr on qtr change	FY25 to date	FY24 to date	YTD change
Sales revenue \$'000	1,506.4	733.7	105%	2,240.1	2,725.1	(18%)
Sales gas & ethane PJ	0.12	0.06	89%	0.18	0.26	(31%)
Production PJ _e ¹	0.12	0.06	90%	0.18	0.26	(31%)
Cash \$ million	2.19	4.00	(45%)	2.19	3.90	(44%)

Totals may not equal summation of sub-totals due to rounding.

Zero lost time injuries were recorded during the period.

This release has been authorised on behalf of the Vintage Energy board by Mr. Neil Gibbins, Managing Director.

For information

Neil Gibbins | Managing Director | +61 8 7477 7680 | info@vintageenergy.com.au

Important information, dates, terms and abbreviations:

Forward looking statements: information on forward looking statements contained in this report provided on the final page of this report.

Dates: unless specified otherwise the term "the quarter" relates to the 3 months ended 31 December 2024 and dates quoted refer to that date in the current calendar year eg "January" refers to January 2025.

Terms and abbreviations: this report may use terminology or abbreviations used in the oil and gas industry. A glossary of such terms is provided for reference at the back of this report.

¹ Petajoule equivalent: comprises sales gas and gas liquids.

Sales

	3 months to 31 Dec '24	Prior Qtr Sept '24	Qtr on qtr change %	YTD FY25	YTD FY24	Year on year % change
Sales revenue \$'000	1,506.4	733.7	<i>105%</i>	2,240.1	2,725.1	<i>(18%)</i>
Sales volume						
TJ	117.3	60.7	<i>93%</i>	178.0	258.3	<i>(31%)</i>
LPG tonne	9.8	25.8	<i>(100%)</i>	25.8	14.1	<i>83%</i>
Condensate bbls	376	227	<i>66%</i>	603	290	<i>107%</i>

Sales revenue of \$1.51 million was recorded for the quarter, 105% higher than the prior quarter revenue of \$0.73 million.

The increase in revenue compared with the prior quarter is attributable to higher gas production during the period. Discussion of factors contributing to the quarter's production is provided following.

As previously advised, sales revenue reported in respect of supply from the Vali gas field comprises sales attracting cash payment and sales for which cash payment has been prepaid. From 1 July 2023, production and sales figures include gas produced under contractual agreement towards consideration for processing and transportation. The financial value of this gas is accounted as non-cash generating sales revenue.

Finance

Cash and net debt

Cash and cash equivalents as at 31 December 2024 was \$2.19 million compared with \$4.00 million at the beginning of the quarter. Net cash outflow from operating activities of \$0.68 million compares to the corresponding outflow of \$1.31 million in the prior quarter.

The \$0.63 million improvement in quarterly outflow from the September quarter is largely accounted for by a \$0.39 million increase in cash receipts from customers (up 55%) and a 46%, \$0.29 million, reduction in corporate and administration costs. Lower exploration cost, higher production costs and staff costs featured in the balance of the movement. Staff costs were \$0.046 million higher than the prior quarter due to the timing of workers compensation premium payments. Wages and salaries were generally in line with the previous quarter.

Staff costs for the December quarter were \$0.17 million lower than the previous December quarter and are expected to fall further due to the restructuring announced on December 17, 2024, which will result in a 41% reduction in head count and direct staff costs which is expected to become apparent from the opening quarter of FY26.

Borrowings net of cash at 31 December were \$7.81 million compared with \$6.00 million at the beginning of the period.

Production

Production data	3 months to 31 Dec '24	Prior Qtr Sept '24	Qtr on qtr change	YTD FY25	YTD FY24	Year on year change
Total production PJe	0.12	0.06	90%	0.18	0.26	(31%)
Sales gas & ethane TJ	115.6	61.0	90%	176.6	259.0	(32%)
LPG tonne	24.0	8.4	186%	32.5	27.0	20%
Condensate bbls	266.0	103.8	156%	369.9	629.6	(41%)

Vintage share of production for the December quarter was 0.12 PJe, 90% higher than the 0.06 PJe produced in the September quarter. The movement in production compared with the previous quarter is due to increased production from the Odin gas field.

Further discussion of the performance of the Vali and Odin gas fields is provided under the heading 'Operations' following.

Corporate

Vintage Energy – Galilee Energy merger proposal

On 12 December 2024, the boards of Vintage Energy and Galilee Energy issued a joint ASX announcement advising the companies have mutually agreed to terminate the previously announced scheme implementation deed (SID).

The termination of the SID follows extensive discussions between the parties whereby the Scheme as originally proposed was no longer believed to be in the best interests of Galilee and Vintage shareholders and the parties have not been able to agree revised terms acceptable to both parties.

Restructuring

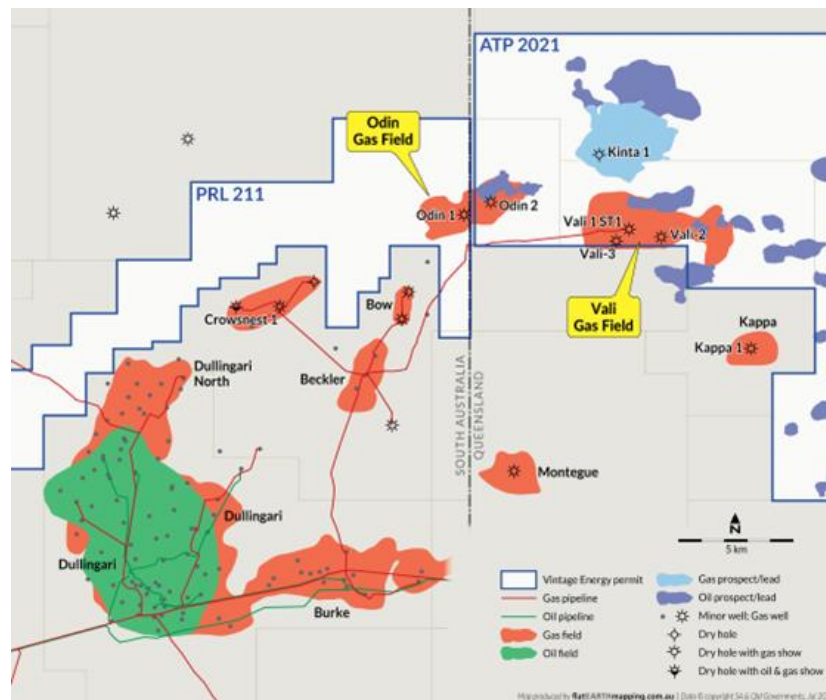
During the quarter, Vintage announced commencement of a business restructuring, forecast to reduce staff headcount by 41% and direct staff salaries by 41%. The reduction in salaries reduces annual salary cost by approximately \$1.14 million. The changes will take place in the first quarter of 2025, and savings in the first half of calendar 2025 will be offset by redundancy costs, with lower staff costs to be apparent thereafter.

Operations

Southern Flank gas fields

Cooper/Eromanga Basins, Queensland and South Australia

Odin and Vali gas fields, PRL 211 and ATP 2021 Cooper Basin



Odin gas field

PRL 211 & ATP 2021

Vintage 50% and operator, Metgasco Ltd 25%, Bridgeport (Cooper Basin) Pty Ltd 25%

Asset overview

The Odin gas field straddles the South Australian – Queensland border, falling within PRL 211 in South Australia and ATP 2021 in Queensland. Vintage is the Operator of both licences, conducting operations through two joint ventures of identical composition.

Odin is located in close proximity to the South Australian Cooper Basin Joint Venture's gas production infrastructure at Beckler, Bow and Dullingari. The field was discovered by the PRL 211 joint venture in 2021 and commenced appraisal production from Odin-1 in September 2023. Odin-1 has been completed to produce from the Epsilon and Toolachee formations, supplying gas to Pelican Point Power (a joint venture of ENGIE and Mitsui Australia) under contract to December 2026.

A second well, Odin-2, successfully appraised the north-eastern section of the field in ATP 2021 in June 2024 and subsequently completed and connected.

Gas Reserves at Odin have been independently assessed and were most recently reported in the company's 2024 Annual Report as comprising 46.2 PJ of Proved and Probable Reserves of gas and gas liquids (Vintage share 23.1 PJ) in the Toolachee, Epsilon, Patchawarra and Tirrawarra formations of the field. Sales gas (including ethane) is assessed to comprise 44.8 PJ (Vintage share 22.4 PJ) of this total.

Activity

Activity at the Odin gas field during the period was chiefly concerned with ongoing investigation and analysis of the impact of scale accumulation in Odin-1 previously reported and commissioning, monitoring and management of initial production from Odin-2.

The accumulation of scale from deposition of mineralised reservoir fluids was found to be impeding flow and production rates from Odin-1. As reported on 1 October, optimisation procedures to deal with scale present downhole delivered an immediate improvement in flow rates, which rose from 1.4 MMscf/d prior to the procedure to average 3.3 MMscf/d in the subsequent 48 hours.

Odin-1 is estimated to have averaged raw gas production of 3.1 MMscf/d during the quarter whilst online following the optimisation procedures.

Scale accumulation was found to be present in the field's surface piping and metering equipment. This scale was found to have interfered with the operation of the meter, resulting in potential under-reporting of Odin gas production rates which is believed to have commenced during October. Consultation with the downstream operator is ongoing to understand the quantum of Odin production potentially under-reported by scale affected metering. Cleaning and recalibration of the metering equipment during late-October, November and December is believed to have yielded brief periods of accurate metering before interference from the reoccurrence of scale accumulation. Scale accumulation does not appear to have impacted metering to the same extent since cleaning on 21st December.

Scale inhibitor chemical injection equipment was installed during December to mitigate further accumulation at the meter. Chemical injection is expected to commence in February following receipt of approval for commencement from the downstream operator was received in late January.

Odin-1 has continued to perform steadily since the September 2024 optimisation procedures, which were accompanied by perforation of intervals in the well's Patchawarra Formation. Reservoirs within the Patchawarra Formation characteristically feature low permeability. Production logging conducted during the quarter confirmed the perforated intervals within the Patchawarra were contributing to Odin-1 gas flows.

A near-term low-cost investigation and production optimisation program was designed during the quarter. The program is under consideration for long term management of scale accumulation.

Odin-2 was brought online on 13 October and produced raw gas at an average rate of 3.00 MMscf/d over its initial 20-hour period, flowing at an average rate of 430 psi through a 68/64" choke. Production rates declined over the quarter, averaging 1.04 MMscf/d in the period to 31 December. At 1 January, the well's production rate had declined to approximately 0.5 MMscf/d. The well's production decline is substantially greater than forecast, and greater than predicted from modelling using post-drill Odin-2 and regional well data. Initial analysis following a December pressure build-up survey indicates the decline in production has arisen from reduced permeability in the near-wellbore region, which could be caused by scale such as seen in Odin-1, in addition to reservoir pressure depletion. A low-cost investigation and production optimisation program is being designed for Odin-2.

The Odin gas field was online for 79.9 days during the quarter compared with 46.1 days in the September quarter. The most significant cause of unavailability related to the connection and commissioning of Odin-2 during October. There was additional downtime for meter cleaning and calibration, memory production logging tool (MPLT) surveys, and for a pressure buildup survey at Odin-2. None of the downtime for the quarter was attributable to downstream outages and there was no impact of weather on production.

Vali gas field

ATP 2021

Vintage 50% and operator, Metgasco Ltd 25% and Bridgeport (Cooper Basin) Pty Ltd 25%

Asset overview

The Vali gas field is located in Queensland, adjacent to the Queensland-South Australia border.

Vali was discovered by Vali-1 ST1 in January 2020 and successfully appraised by Vali-2 and Vali-3. Reserves at Vali have been independently certified and most recently reported in the 2024 Annual Report as comprising gross Proved and Probable reserves equivalent to 100.0 PJe (Vintage share 50.0 PJe)² of gas and gas liquids. Sales gas and ethane account for 96.8 PJ (Vintage share: 48.4 PJ) of the 2P reserves.

The field has three wells completed and connected to the Moomba gas gathering network for supply to the eastern Australian domestic energy market. Vali-1 is the only well currently producing, Vali-2 and Vali-3 having been shut-in pending resolution of fluid-production issues. Vali is currently subject to a long-term production appraisal program with gas produced being supplied to AGL Energy under a supply agreement to December 2026.

Activity

The Vali gas field averaged raw gas production of 1.01 MMscf/day compared with 1.25 MMscf/day in the prior quarter. Availability improved, with the field online for 91.7 days compared with 80.7 days in the prior quarter. The 0.3 days downtime was attributable to a downstream production outage.

Production was almost entirely from Vali-1. Vali-2 was open for production for 8.8 days during the quarter and shut-in for the majority of the quarter due to ongoing fluid production.

² As reported in the Vintage Energy 2024 Annual Report. Vintage Energy confirms it is not aware of any new information or date that materially affects the information included in the announcement and that all the material assumptions and technical parameters underpinning the estimates in the announcements continue to apply.

Otway Basin, South Australia/Victoria

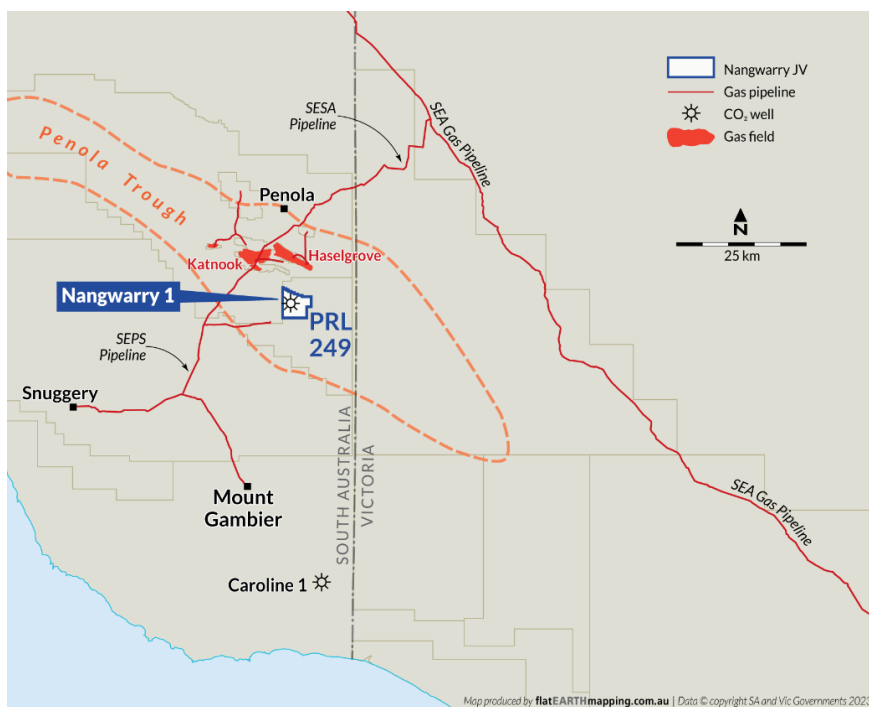
PRL 249 (ex-PEL 155)

Vintage 50%, Otway Energy Pty Ltd 50% and operator

Asset overview

PRL 249 contains the Nangwarry gas field, discovered in January 2020. On testing, Nangwarry-1 produced raw gas (~93% CO₂, ~6% methane and ~1% nitrogen), at flow rates of 10.5-10.8 MMscfd, measured through a 48/64" choke at a flowing wellhead pressure of 1,415 psi over a 36-hour period.

Location of PRL 249 and Nangwarry-1, Otway Basin, South Australia



The Nangwarry resource is assessed to have the volume, quality and reservoir properties for an economic, significant and long-life food-grade CO₂ production asset.

Recoverable CO₂ sales gas and Contingent Resources of gas hydrocarbons at Nangwarry have been independently assessed and announced to the ASX on 12 July 2021. Recoverable CO₂ sales gas was assessed at the Best Estimate level as 25.9 bcf gross and 12.9 bcf net to Vintage. 2C Contingent Resources of gas hydrocarbons were assessed to be 1.6 bcf gross and 0.8 bcf net to Vintage.

These volumes are considered sufficient to provide a multi-decade feedstock source for production of food or industrial grade CO₂, a required input for a wide range of sectors including hospitality, food and beverage manufacture, protected horticulture, chemical, cold storage, medical device and other manufacturing. Local supply of naturally occurring CO₂ was provided until 2017 by the now depleted onshore Otway Basin well Caroline-1.

Vintage is seeking an outcome which will recognise the economic value of the resource. Realisation of this value will require processing of raw gas to food grade standard and liquefaction for transport to market and storage.

Activity

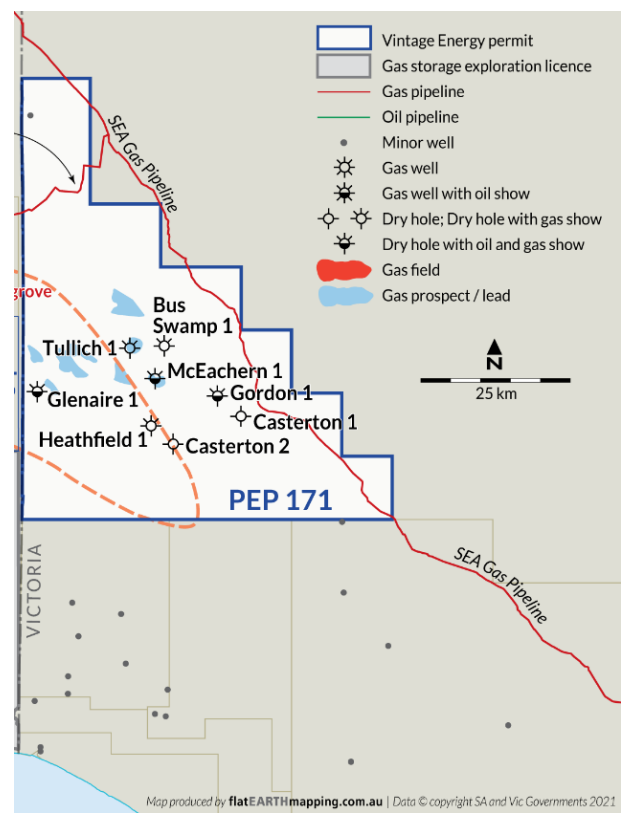
Engagement continued with participants in the industrial gas and infrastructure sectors and government to identify parties interested in a collaborative wellhead-to-product-delivery solution for commercialisation, or ownership, of the Nangwarry resource.

PEP 171

Vintage 25% and operator, Somerton Energy Pty Ltd (a subsidiary of Amplitude Energy Limited 75%)

PEP 171 is located in the onshore Otway Basin and effectively encompasses the entirety of the Victorian section of the Penola Trough. Exploration in the nearby South Australia section has confirmed the prospectivity of the Penola Trough for conventionally produced gas, most significantly at Haselgrove by Beach Energy Ltd.

Location of PEP 171, Otway Basin, Victoria



The expiry of the Victorian moratorium on onshore gas exploration on 1 July 2021, was followed by new regulations on 22 November 2021. All previous existing oil and gas exploration permits of good standing (which includes PEP 171), were restarted from 1 July 2021 for their first 5-year term.

Activity

An operations plan for the Sparger 3D seismic survey has been submitted to the regulator, and a suspension & extension application was submitted and granted, to allow time for the scheduling and acquisition of the survey.

Galilee Basin, Queensland

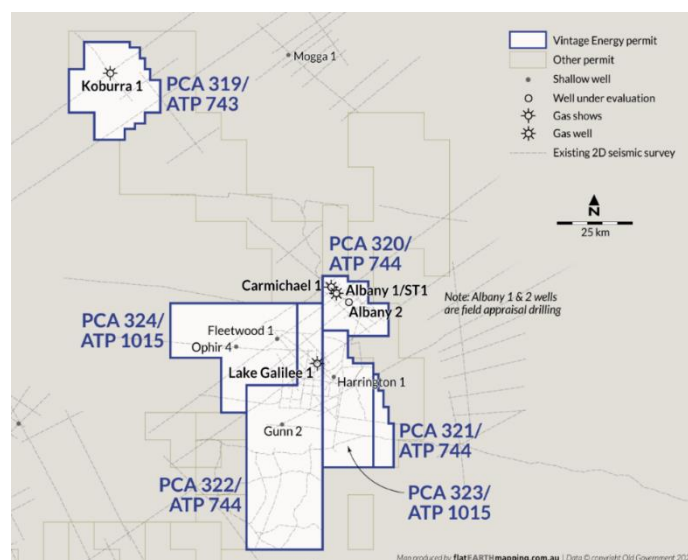
ATPs 743, 744, 1015 (“Deeps”) | PCA’s 319 - 324

Vintage 30%, Comet Ridge Ltd (“Comet”) 70% and operator

Asset overview

The Galilee Basin is a lightly explored gas province in proximity to market and the proposed Galilee-Moranbah pipeline. In 2017, Vintage acquired a 30% participation in the Deeps sandstone reservoir sequence of ATP 744, ATP 743 & ATP 1015 (all strata commencing underneath the Permian coals (Betts Creek Beds or Aramac coals) with the main target being the Lake Galilee Sandstone sequence).

Location of ATPs 743, 744, 1015 (“Deeps”) | PCA’s 319 - 324 Galilee Basin, Queensland



The Deeps was tested in 2019 by Albany-1, which recorded the first measurable gas flow from the Galilee Basin, flowing at 230,000 scf/d from the top 10% of the target reservoir without stimulation. Albany-2 was drilled and hydraulically stimulated. Albany-1 was side-tracked but not flow-tested due to the cessation of operations during the Covid pandemic.

Activity

The Operator is continuing to progress the geological & geophysical studies, in conjunction with commercial analysis of the Galilee Deeps project. There was no significant activity during the period.

Bonaparte Basin, Northern Territory

EP 126

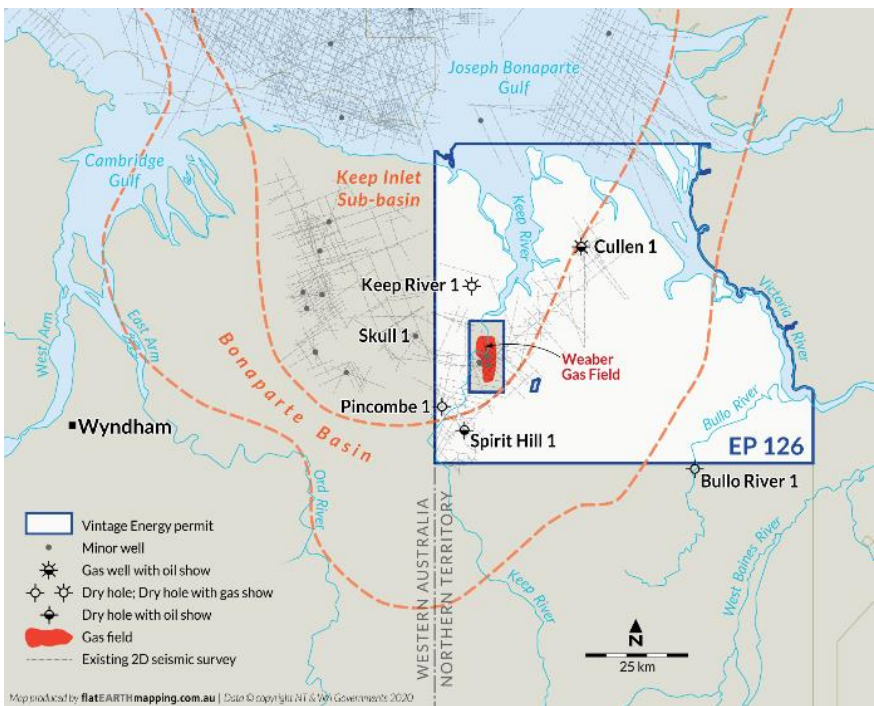
Vintage 100%

Asset overview

The Bonaparte Basin is a frontier basin in the north of the Northern Territory with a proven hydrocarbon system. Several large gas fields have been discovered offshore (undeveloped Contingent Resources of 2.7 Tcf in Petrel, Tern and Frigate) and the producing Black Tip field (2P 933 Bcf) supplies gas to Darwin. The onshore Weaber Gas Field (RL-1, Advent Energy 100%), and surface bitumen seeps, provide direct evidence of a working petroleum system in the Keep Inlet Sub-Basin.

EP 126 is a low-cost entry with excellent exploration potential encompassing an area of 6,716 km², hosting multiple play types, with potential for large volumes of gas and oil. Cullen-1 was drilled in 2014, with both oil and gas shows, and was cased and suspended to be available as an option to test.

Location of EP 126, Bonaparte Basin, Northern Territory



Activity

There was no activity of significance in relation to this permit. On-site work is suspended pending resolution of discussions with the Northern Territory government in relation to the declaration of approximately 50% of the permit, including the Cullen-1 well site, as a 'Reserved Area'.

Equity

The company had 1,669,531,280 ordinary shares on issue at the end of the quarter.

Related parties

Payments to related parties, as disclosed at Item 6.1 in the company’s cash flow report attached to this report (Appendix 5B) was \$121,352 being remuneration and superannuation.

Top 10 Shareholders

As at 15 January 2025

Position	Holder Name	Holding	% IC
1	J P MORGAN NOMINEES AUSTRALIA PTY LIMITED	212,188,656	12.71%
2	VINTAGE UNDERWRITING INVESTMENTS PTY LTD	69,569,357	4.17%
3	ALLEGRO CAPITAL NOMINEES PTY LTD <ALLEGRO CAPITAL ACCOUNT>	59,855,960	3.59%
4	GELLE PTY LTD <GD BRERETON FAMILY ACCOUNT>	51,879,301	3.11%
5	ITA VERO PTY LTD <THE RICHMOND A/C>	34,846,154	2.09%
6	COOEE INVESTMENTS PTY LTD	30,762,231	1.84%
7	MR ANTONIOS SYRIANOS <TONY SYRIANOS FAMILY A/C>	30,000,000	1.80%
8	HOWZAT SERVICES PTY LTD <HOWARTH SUPER FUND A/C>	27,124,395	1.62%
9	VIEWADE PTY LIMITED <OLIVER SUPER FUND A/C>	24,229,329	1.45%
10	LILICRAP SUPER PTY LTD <LILICRAP SUPER FUND A/C>	22,896,924	1.37%
	Total	563,352,307	33.74%
	Total issued capital - selected security class(es)	1,669,531,280	100.00%

Forward looking statements

This document may include forward looking statements. Forward looking statements include, but are not necessarily limited to, statements concerning Vintage's planned operational program and other statements that are not historic facts. When used in this document, the words such as "could", "plan", "estimate", "expect", "intend", "may", "potential", "should" and similar expressions are forward looking statements. Although Vintage believes its expectations reflected in these are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements. Vintage confirms that it is not aware of any new information or data that materially affects the information included in this announcement and that all material assumptions and technical parameters underpinning this announcement continue to apply and have not materially changed.

Glossary

Terms and abbreviations for resources and reserves as per the SPE-PRMS

PRMS	Petroleum Resources Management System. Reserves and Resources are defined by the Society of Petroleum Engineers ('SPE'), American Association of Petroleum Geologists ('AAPG'), World Petroleum Council ('WPG') and the Society of Petroleum Evaluation Engineers ('SPEE'). The detail of the PRMS is available as a download from the website of the SPE: www.spe.org The petroleum resources classification framework is illustrated below:
Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered (hypothetical) accumulations by application of future development projects. The categories of decreasing certainty are Low, Best and High Estimates.
Contingent Resources	Those quantities of petroleum are estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet currently mature enough for commercial development due to one or more contingencies. The categories of decreasing certainty are Low, Best and High estimates.
1C	Low estimate of Contingent Resources.
2C	Best estimate of Contingent Resources.
3C	High estimate of Contingent Resources.
Reserves	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. The categories in decreasing certainty are Proved, Probable and Possible.
1P, Proved	Proved reserves (deterministic or probabilistic).
2P, Proved and Probable	Proved plus Probable reserves (deterministic or probabilistic).
3P, Proved, Probable and Possible	Proved plus Probable plus Possible reserves (deterministic or probabilistic).
P10 Probabilistic Estimate	From the probabilistic method there is a less than 10% cumulative probability that quantities estimated would ultimately be exceeded.

General terms and abbreviations of the petroleum industry that may appear in this report

2D	Two dimensional; usually referring to a seismic survey with a coarse grid of orthogonal lines.
3D	Three dimensional; usually referring to a seismic survey with a fine grid of orthogonal lines.
ASX	Australian Securities Exchange.
ATP	Authority to Prospect which is an exploration licence in Queensland.
B	Billion 10 ⁹ , or 1,000 million.
bbl	One barrel of crude oil contains 42 US gallons (or 34.97 imperial gallons, or, 159 litres).
Bcf	Billion cubic feet.
Boe	Barrels of oil equivalent. Natural gas is converted to barrels of oil equivalent generally using a ratio of approximately 6,000 cubic feet of natural gas as an amount equivalent to one barrel of oil.
Bopd	A liquid flow rate expressed in barrels of oil per day.
Condensate	A liquid hydrocarbon phase that is slightly lighter than and with less calorific content than crude oil. More usually occurs in association with natural gas. It is gaseous at reservoir conditions but will condense from gaseous vapour to a liquid at the lesser temperature and pressure at standard surface conditions.
EP	Exploration Permit for petroleum as in the Northern Territory.
GJ	Gigajoule. A joule is a measure of heating value. 1 GJ is equal to 1 x 10 ⁹ joules.
Km	Kilometres.
Km²	A square kilometre.
LPG	Liquified petroleum gas such as butane or propane.
m	Metres

M	1,000
MM	Millions 10 ⁶
Net pay	The thickness of reservoir considered to be gas or oil bearing and capable of contributing to production into the wellbore. Usually there will be several cutoff parameters including a porosity minimum, a shale maximum and a water saturation maximum.
PCA	Potential Commercial Area as used in Queensland
PEL	Petroleum Exploration Licence as used in South Australia.
PJ	Petajoule. A joule is a measure of heating value. 1 PJ is equal to 1 x 10 ¹⁵ joules
PRL	Petroleum Retention Licence as used in South Australia
Resources	The term "Resources" as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced.
scf/d	A flow rate in standard cubic feet per day.
TCF	Trillion cubic feet of gas.
TJ	Terajoule; a joule is a measure of heating value. 1 TJ is equal to 1 x 10 ¹² joules

Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity

VINTAGE ENERGY LTD

ABN

56 609 200 580

Quarter ended ("current quarter")

31 December 2024

Consolidated statement of cash flows		Current quarter \$A'000	Year to date (6 months) \$A'000
1.	Cash flows from operating activities		
1.1	Receipts from customers	1,097	1,806
1.2	Payments for		
	(a) exploration & evaluation	0	(64)
	(b) development		
	(c) production	(520)	(812)
	(d) staff costs	(827)	(1,608)
	(e) administration and corporate costs	(334)	(952)
1.3	Dividends received (see note 3)		
1.4	Interest received	8	23
1.5	Interest and other costs of finance paid	(274)	(552)
1.6	Income taxes paid		
1.7	Government grants and tax incentives		
1.8	Other (rehabilitation expense)	(16)	(16)
1.9	Net cash from / (used in) operating activities	(866)	(2,175)

2.	Cash flows from investing activities		
2.1	Payments to acquire or for:		
	(a) entities		
	(b) tenements		
	(c) property, plant and equipment		
	(d) exploration & evaluation	(917)	(3,238)
	(e) investments		
	(f) other non-current assets		

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Consolidated statement of cash flows		Current quarter \$A'000	Year to date (6 months) \$A'000
2.2	Proceeds from the disposal of:		
	(a) entities		
	(b) tenements		
	(c) property, plant and equipment		
	(d) investments		
	(e) other non-current assets		
2.3	Cash flows from loans to other entities		
2.4	Dividends received (see note 3)		
2.5	Other (provide details if material)		
2.6	Net cash from / (used in) investing activities	(917)	(3,238)

3.	Cash flows from financing activities		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)		
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options		
3.4	Transaction costs related to issues of equity securities or convertible debt securities		
3.5	Proceeds from borrowings		
3.6	Repayment of borrowings		
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (lease payments)	(36)	(73)
3.10	Net cash from / (used in) financing activities	(36)	(73)

4.	Net increase / (decrease) in cash and cash equivalents for the period		
4.1	Cash and cash equivalents at beginning of period	4,006	7,673
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(866)	(2,175)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(917)	(3,238)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(36)	(73)

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Consolidated statement of cash flows		Current quarter \$A'000	Year to date (6 months) \$A'000
4.5	Effect of movement in exchange rates on cash held		
4.6	Cash and cash equivalents at end of period	2,187	2,187

5.	Reconciliation of cash and cash equivalents at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	Current quarter \$A'000	Previous quarter \$A'000
5.1	Bank balances	2,049	3,868
5.2	Call deposits *	30	30
5.3	Bank overdrafts		
5.4	Other (security deposits) *	108	108
5.5	Cash and cash equivalents at end of quarter (should equal item 4.6 above)	2,187	4,006

*Amount is restricted

6.	Payments to related parties of the entity and their associates	Current quarter \$A'000
6.1	Aggregate amount of payments to related parties and their associates included in item 1	121
6.2	Aggregate amount of payments to related parties and their associates included in item 2	

Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

7.	Financing facilities <i>Note: the term "facility" includes all forms of financing arrangements available to the entity.</i> <i>Add notes as necessary for an understanding of the sources of finance available to the entity.</i>	Total facility amount at quarter end \$A'000	Amount drawn at quarter end \$A'000
7.1	Loan facilities	10,000	10,000
7.2	Credit standby arrangements		
7.3	Other (please specify)		
7.4	Total financing facilities	10,000	10,000
7.5	Unused financing facilities available at quarter end		
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well. As announced to the market 14 June 2022, a \$10 million debt facility from PURE Resources Fund has been drawn down. Term: 48 months from first draw down. Interest rate: 11.0%, reducing to 8.5% once certain operational cash flow conditions are met. Security: first ranking security over Vintage assets, where joint venture arrangements permit. Financial covenants include: requiring a minimum of \$1.5 million cash in the bank. Early repayment provisions use a sliding scale penalty of 1.5% to 1.0% of the funds.		

8.	Estimated cash available for future operating activities	\$A'000
8.1	Net cash from / (used in) operating activities (item 1.9)	(866)
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(917)
8.3	Total relevant outgoings (item 8.1 + item 8.2)	(1,783)
8.4	Cash and cash equivalents at quarter end (item 4.6) **	2,049
8.5	Unused finance facilities available at quarter end (item 7.5)	
8.6	Total available funding (item 8.4 + item 8.5)	2,049
8.7	Estimated quarters of funding available (item 8.6 divided by item 8.3)	1.1

Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:

8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?

Answer: The company expects net operating cash flows to improve in the short-to-medium term, with the continued strong production performance of Odin-1 post scale removal from the borehole (as advised 1 October 2024), removal of scale from metering equipment and consequent accurate and higher rate readings from the meter and the installation of scale inhibitor injection equipment in-line ahead of the metering equipment. Low cost production optimisation works are being planned to investigate the presence of, and address, scale formation across the whole Southern Flank Gas project (Odin and Vali) Fields. Outgoing cash flows from investing activities are expected to reduce due to Odin-2 connection works having been completed in October 2024. The company also announced a restructure in December (ASX release dated 17 December 2024) effective from the first quarter 2025 reducing head count and salaries by 41%, reducing annual salary cost by approximately \$1.14 million. Savings in the first half of 2025 will be offset by redundancy costs, hence the full impact of savings will become evident across the second half of CY 2025.

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: The company is confident it can fund its ongoing expenditure requirements using operating cash flow and other available options including debt, equity, farm-downs and non-core asset sales if required.

8.8.3 Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?

Answer: The company expects to be able to continue its operations and meet its business objectives, with operational cash flow expected to increase with the additional gas supply enabled by scale removal and planned optimisation works, as highlighted above.

Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

** Difference between item 8.4 and item 4.6 reflects amounts that are restricted. Refer item 5.1.

Compliance statement

- 1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.
- 2 This statement gives a true and fair view of the matters disclosed.

Date: 31 January 2025

Authorised by: By the board
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.

2. If this quarterly cash flow report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, *AASB 6: Exploration for and Evaluation of Mineral Resources* and *AASB 107: Statement of Cash Flows* apply to this report. If this quarterly cash flow report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [name of board committee – eg Audit and Risk Committee]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.