Central Petroleum

CTP.AX

A research platform of MST Financial

13 August 2026

Cashflow Boost for FY27

Equity Research Australia
Energy

Michael Bentley, Senior Analyst

NEED TO KNOW

- Mereenie gas overlift repaid; ~A$7m pa cash uplift
- Palm Valley drilling underway; ~40% capacity uplift
- June quarter pricing hits new high; volumes down on maintenance
- Otway: Enterprise North exploration well progressing

Gas overlift repaid; ~A$7m pa returns to cashflow: CTP made its final delivery against the Mereenie gas overlift (repayment in gas) liability in mid-May, concluding an obligation that has absorbed 2 TJ/d of production at nil revenue since 2020. CTP estimates the cessation will add more than A$7m pa to cashflow, with the September quarter being the first to reflect it in full.

Palm Valley drilling underway; circa 40% capacity uplift targeted: Drilling of PV14 commenced on 25 July, with gas to customers targeted from October. The two wells are intended to restore Palm Valley sales capacity to approximately 14 TJ/d (100% JV) from 5.8 TJ/d at 30 June, and to deliver at least 10 PJ gross over their operating lives.

June quarter pricing at a new high; volumes lower on planned maintenance: Revenue of A$10.9m was 3.9% below the March quarter on lower sales volumes of 1.0 PJe (7.3% below the March quarter), following a five-day Mereenie shutdown and Palm Valley pre drilling work. Realised gas pricing increased 3.2% to A$10.38/GJ, the highest of FY26. FY26 revenue of A$43.9m was 3.7% above FY25.

Otway and Cooper exploration provides East Coast market exposure: Operator ADZ is progressing an exploration well at Enterprise North in PEP169, in which CTP acquired a 20% interest in January, and is reprocessing seismic over two Cooper Basin targets. Exploration success would provide CTP exposure to the East Coast gas market.

Investment Thesis

Contracted, CPI-linked cashflow now converts fully to cash: CTP's gas sales agreements with the NT Government secure a market for the majority of firm production to the end of 2034 at CPI-linked pricing with take-or-pay, from one of the lowest-risk counterparties in the sector. Against FY26 net operating cashflow of A$10.3m, an incremental A$7m pa is a step-change.

Funded, near-term production growth at low subsurface risk: The Palm Valley program is funded from existing cash and an expanded A$15m finance facility. The processing facility is in place and well below capacity, tie-in distances are short and offtake is contracted, leaving well deliverability as the principal residual risk.

Valuation and Risks: CTP Stacks Up on Every Metric

Our base-case NPV is A$0.24/share (previous A$0.22), highlighting CTP's substantial undervaluation. At current prices, FY27E P/OCF is 1.3x, P/E 1.8x, and EV/EBITDAX 1.3x. The share price implies a gas price of A$6.77/GJ, well below our FY26 forecast of A$10.00/GJ and CTP's latest realised price of A$10.38/GJ. Successful Palm Valley wells PV14 and PV15 have the potential to add significant value. Key risks include potential production issues, lack of exploration success and unsuccessful PV development wells.

Central Petroleum is the NT's largest onshore gas operator, with a portfolio of gas and oil assets focused on the Amadeus Basin. Its strategy is to unlock andEast Coast commercialise the vast energy potential of the Central Australian basins to take advantage of a tight supply/demand balance in the domestic gas market. www.centralpetroleum.com.au

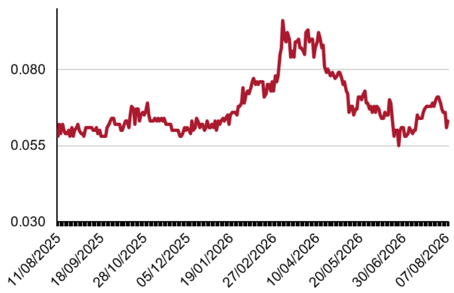
Valuation	**A$0.240** *(from A$0.220)*
Current price	**A$0.050**
Market cap	**A$49m**
Net debt	**A$5.0m** *(30 June 2026)*

Upcoming Catalysts / Next News

Upcoming Catalysts / Next News

Period	
1QFY27	PV14 gas to customers (October)
1QFY27	First full quarter free of overlift
2QFY27	PV15 drilling and connection
FY27	Enterprise North exploration well

Share Price (A$)



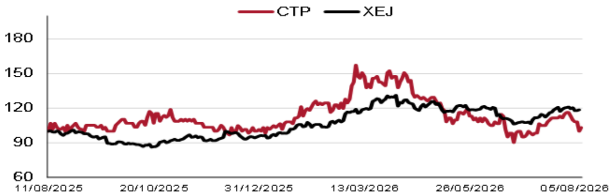
Source: FactSet, MST Access.

Figure 1: Financial summary, year-end 30 June

Central Petroleum Limited (ASX:CTP)

Year-end 30 June		
Share Price	A$/sh	0.065
52 week high/low	A$/sh	0.10/0.05
Valuation	A$/sh	0.24
Market Cap (A$m)	A$m	49
Net Cash / (Debt) (A$m)	A$m	(5)
Enterprise Value (A$m)	A$m	54
Shares on Issue	m	751
Options/Performance shares	m	37
Potential Diluted Shares on Issue	m	787

CTP Relative to XEJ 12 months



Ratio Analysis	2024A	2025A	2026E	2027E	2028E
EPS	1.68	1.04	0.38	3.68	6.81
P/E (x)	3.1	5.3	16.0	1.8	1.0
EPS Growth (%)		-38%	-63%	864%	85%
CFPS (A¢)	0.93	1.92	1.38	4.88	8.29
P/CF (x)	5.7	2.9	4.4	1.3	0.8
DPS	–	–	–	–	–
Dividend Yield (%)	–	–	–	–	–
EV / EBITDA (x)	1.6	2.1	4.5	1.4	0.1
EV / EBITDAX (x)	2.7	1.9	2.5	1.3	0.1
EV / boe (x)	49.2	47.4	69.5	48.8	1.2
EV / PJe (x)	8.2	7.9	11.6	8.1	0.2
FCFPS					
FCF Yield (%)					

Assumptions (Yr end Jun)	2024A	2025A	2026E	2027E	2028E
Brent Oil Price (US$/bbl)	80.62	72.18	73.00	74.8	76.7
Exchange Rate (A$1:US$)	0.656	0.648	0.648	0.648	0.648
Gas Price (A$/GJ)	7.35	8.66	9.99	10.25	10.51

Production	2024A	2025A	2026E	2027E	2028E
Gas (TJ/d)	12.0	12.3	11.7	18.5	55.7
Gas (PJ)	4.4	4.5	4.3	6.8	20.4
LPG (kt)	–	–	–	–	–
Oil / Condensate (mmbbl)	0.03	0.03	0.02	0.02	0.02
Total (mmboe)	**0.76**	**0.78**	**0.73**	**1.15**	**3.42**
Gas (mmboe)	0.73	0.75	0.71	1.13	3.40
LPG (mmboe)	–	–	–	–	–
Oil / Condensate (mmboe)	0.03	0.03	0.02	0.02	0.02
Year End Reserves 2P (mmboe)	**12.6**	**12.6**	**11.8**	**10.7**	**7.3**

Reserves and Resources As at 30 June 2024	Working Interest	1P Gas (PJ)	2P Gas (PJ)	1P Liquids (mmbbl)	2P Liquids (mmbbl)
Mereenie (OL 4 / OL 5)	25%	28.1	36.6	0.30	0.36
Palm Valley (OL 3)	50%	10.9	11.7	–	–
Dingo (L7)	50%	18.7	22.8	–	–
Total		**57.6**	**71.2**	**0.30**	**0.36**

	A$m	Risking	A$m	A$ps
Mereenie - OL4 & OL5 (25%)	83	100%	83	0.11
Palm Valley - OL3 (50%)	29	100%	29	0.04
Dingo - L7 & PL30 (50%)	50	100%	50	0.07
Enterprise North - PEP 169 (20%)	24	65%	16	0.02
Cooper Basin (49%)	3	100%	3	0.01
Total Operations	**188**		**180**	**0.25**
Net Cash / (Debt)	(7)	100%	(7)	(0.01)
Admin / Corporate / Other	(35)	100%	(35)	(0.05)
Exploration (risk-adjusted)	23	50%	11	0.02
Mereenie & Palm Valley 2C gas (risked)	39	65%	25	0.03
TOTAL VALUATION	**208**		**175**	**0.24**

Profit & Loss (A$m)	2024A	2025A	2026E	2027E	2028E
Oil / Condensate Revenue	3	3	1	3	3
LPG Revenue	–	–	–	–	–
Gas Revenue	34	40	42	69	102
Revenue	**37**	**43**	**44**	**72**	**105**
Operating Costs	(18)	(18)	(16)	(20)	(23)
Government Resource Taxes	(3)	(4)	(4)	(5)	(9)
Exploration & Development Expense	(4)	(2)	(9)	(3)	(4)
Other Net Income / Expense	11	(1)	(4)	(4)	(5)
EBITDA	**24**	**18**	**11**	**40**	**64**
EBITDAX	**14**	**20**	**20**	**42**	**68**
Depreciation & Amortisation	(8)	(7)	(6)	(9)	(12)
EBIT	16	11	5	30	53
Net Interest Expense	(3)	(3)	(2)	(3)	(2)
Net Profit before-tax	12	8	3	28	51
Tax Expense / Benefit	–	–	–	–	–
Reported Profit	**12**	**8**	**3**	**28**	**51**
Exceptional items / non-recurring	14	–	4	–	–
Underlying NPAT	**(1)**	**8**	**7**	**28**	**51**

Cash Flow (A$m)	2024A	2025A	2026E	2027E	2028E
Pretax Profit	12	8	3	28	51
D&A & Other Non-Cash Items	-6	7	7	9	11
Tax Paid	–	–	–	–	–
Cash from Operating Activities	**7**	**14**	**10**	**37**	**62**
Development Capex	(3)	(9)	(7)	(35)	(10)
Acquisitions/Other (Net of Sales)	12	1	(11)	(4)	–
Dividends Paid	–	–	–	–	–
Free Cash Flow	**16**	**4**	**(9)**	**(2)**	**52**
Cash Provided by Financing	(5)	(2)	(1)	(3)	(8)
Net Change in Cash	**11**	**2**	**(10)**	**(5)**	**44**

Balance Sheet (A$m)	2024A	2025A	2026E	2027E	2028E
Cash & short term deposits	25	27	20	15	59
Receivables	5	7	7	12	17
Inventories	4	4	6	9	14
Property, Plant and Equipment	56	58	60	87	89
Capitalised exploration	8	8	7	6	5
Intangibles and Goodwill	2	2	2	2	2
Other assets	4	8	8	8	9
Total assets	**104**	**114**	**110**	**140**	**195**
Creditors	3	5	4	7	10
Borrowings	23	23	26	23	14
Other liabilities	45	45	32	35	44
Total liabilities	**71**	**73**	**62**	**64**	**68**
Shareholder equity	33	41	48	76	127
Shareholder Equity + Total Liabilities	104	114	110	140	195

Source: CTP, MST estimates.

4QFY26: Record Prices offset by Lower Volumes

Revenue eases as Mereenie and Palm Valley prepare for growth

CTP's June-quarter (4QFY26) result reflected a period of preparation rather than a downturn in performance. Revenue and volumes were lower on planned maintenance at Mereenie and preparation at Palm Valley for the tie-ins for two new wells. Realised pricing reached a new high.

During the quarter, the gas overlift liability was extinguished, and drilling commenced at Palm Valley in July.

Funding: cash position improves despite drilling expenditure

Results: Cash was A$20.4m at 30 June, up from A$19.5m at 31 March. Net debt was A$5.0m, including A$2.5m held as security for the loan facility.

Net operating cashflow after exploration and net interest costs was A$3.6m, consisting of cash receipts of A$12.5m less:

- transportation and corporate costs of A$6.9m.
- exploration and appraisal expenditure of A$2.0m including A$1.7m of site preparation and procurement for the new Palm Valley wells.
- capital expenditure was A$1.6m, principally surface facilities for the new wells and sustaining capex.
- A$0.4m was expended on purchasing CTP shares on-market for the employee share scheme trust.

The scheduled A$0.76m quarterly loan interest payment was capitalised into the loan balance.

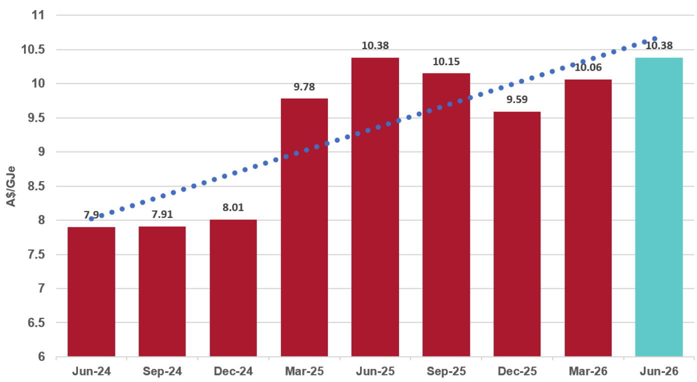
Outlook: We expect cash conversion to improve materially from the September quarter, with the full A$1.75m per quarter overlift benefit flowing and pre-drilling connections completed. Exploration and capital expenditure will remain elevated through 1H FY27 while PV14 and PV15 are drilled and connected (estimated total capex A$26m to CTP), with the program fully funded via operating cashflow, A$20.4m of cash and A$17.5m of undrawn capacity under the expanded Macquarie facility.

Sales price: A$10.38/GJ, a new high under the NT contracts

Results: Realised gas prices averaged A$10.38/GJ for the June quarter, up 3.2% from A$10.06/GJ in March **and 19% above the FY25 average of A$8.74/GJ**. FY26 realised gas pricing averaged A$9.96/GJ, up 14% year on year. Crude and condensate contributed A$0.2m for the quarter and A$1.4m for the year, down from A$3.4m in FY25 as oil offtake was progressively constrained.

Outlook: We expect pricing to continue at or above current levels as legacy contracts roll off and volumes under the new NT Government Gas Sales Agreement (GSA) commence from 2HCY26 at a fixed, CPI-escalated price. We retain a gas price assumption of A$10.00/GJ for FY27 and for the long term, which we continue to regard as conservative relative to a realised A$10.38/GJ.

Figure 2: Realised price – last 2 years



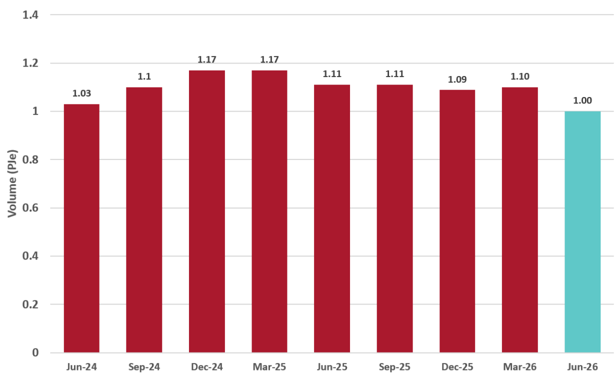
Source: CTP

Sales volumes: lower on planned maintenance and turndown

Results: CTP sold 1.0 PJe (Central share) in the June quarter, 7.3% below the March quarter. Mereenie gross gas sales averaged 25.5 TJ/d (100% JV), 7% lower on a scheduled five-day shutdown in May, with sales capacity of approximately 26.8 TJ/d at quarter end. Palm Valley averaged 5.6 TJ/d gross (2.8 TJ/d Central share) after a pre-emptive 4.5-day shutdown and a temporary partial turndown to prepare connections for the two new wells; sales capacity was approximately 5.8 TJ/d at quarter end. Dingo delivered 4.23 TJ/d gross (2.1 TJ/d Central share), close to contract maximums. Oil sales averaged 165 bbls/d (100% JV) and have been suspended indefinitely from mid-June under revised oil specification requirements.

Outlook: We expect volumes to recover through the September quarter as maintenance is completed, and to increase once PV14 is connected from October. Subject to well performance, Palm Valley sales capacity is targeted to return to the facility limit of approximately 14 TJ/d (100% JV), delivering at least 10 PJ of gas gross over the wells' operating lives. Oil is the principal negative: with sales suspended and no timeline for resolution, we assume no Mereenie oil revenue in FY27 until CTP secures alternative commercial arrangements.

Figure 3: Sales volumes last 2 years



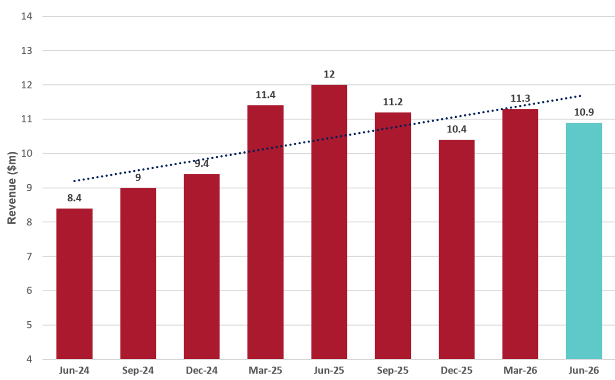
Source: CTP

Revenues: FY26 record of A$43.9m despite lower volumes

Results: June-quarter revenue was A$10.9m, 3.9% below the A$11.3m March quarter, with lower gas sales volumes only partly offset by a 3.6% increase in realised average prices. Gas contributed A$10.7m and crude and condensate A$0.2m. FY26 revenue of A$43.9m was 3.7% above FY25's A$42.4m: a 10% lift in realised prices more than offset a 6% fall in volumes driven by oil offtake constraints and pipeline restrictions during 1H FY26.

Outlook: We expect FY27 revenue to build sequentially. The September quarter should benefit from the restoration of full Mereenie and Palm Valley availability, the December quarter from the connection of PV14, and the second half from a full contribution from both wells under the new GSA. The principal offset is the loss of Mereenie oil revenue. The continued closure of the Northern Gas Pipeline (NGP), which constrains East Coast optionality until Beetaloo volumes restore minimum throughput, will have minimal impact through CY27, as almost all of CTP's expected production is already contracted within the NT.

Figure 4: Revenue last 2 years



Source: CTP

Corporate: Facility Expanded; Buy-Back Suspended

CTP secured an increase to its existing loan facility in April, providing access to up to A$15m of working capital to support the acceleration of drilling at Palm Valley, available for drawdown through to 31 December 2026 if required. Drawings are repayable in equal quarterly instalments from March 2027 to December 2029 and may be repaid early without penalty. At quarter end, total loan facilities were A$43.0m with A$25.5m drawn and A$17.5m available, under a Macquarie secured term facility maturing 31 December 2029 at a floating rate of 12.5115%. The June quarter interest payment of A$0.76m was capitalised into the loan balance.

There has been no activity under CTP's buy-back scheme since January as cashflow has been prioritised to the committed investment in the PV wells and possible exploration drilling in the newly acquired Cooper and Otway Basin permits in CY27.

Gas Overlift Done: ~A$7m pa Returns to Cashflow

How gas overlift arises

In a producing joint venture, each participant is entitled to a share of production corresponding to its equity interest. In practice, physical gas does not divide precisely along those lines. Processing facilities operate continuously, customers nominate different volumes on different days, and one participant will routinely take more gas than its entitlement while another takes less. The participant taking more is described as 'overlifted'; the participant taking less is 'underlifted'.

The resulting imbalance is generally not settled in cash. It is settled in kind, with the overlifted participant repaying the gas from its own future entitlement and receiving no revenue for those volumes. The overlifted participant nonetheless continues to bear the full cost of producing, compressing, transporting and delivering the repayment gas, while the associated revenue accrues to the underlifted participant.

This has been the position at Mereenie. Since 2020, CTP has been repaying an overlift balance by delivering 2 TJ/d of its production share at nil net revenue (in practice CTP has sold the gas, recording the revenue, but then effectively passing this through as a production cost). Against Mereenie gross gas sales of approximately 26 TJ/d and CTP's 25% working interest of around 6.4 TJ/d, the 2 TJ/d represented a substantial proportion of CTP's entitlement, estimated by CTP at more than A$7m pa of cashflow, or A$1.75m per quarter.

Why the cashflow effect exceeds the revenue effect

The final delivery was made in mid-May 2026, from which point the 2 TJ/d reverts to CTP and continues to be sold at contract prices, but CTP no longer has to pass the proceeds through as a production cost. The production and operating costs associated with those volumes were already being incurred and already sat within CTP's cost base. Recovering the volume therefore recovers close to a full margin rather than a gross margin net of incremental cost, and requires no additional drilling.

Only the final two weeks of the June quarter captured any benefit. CTP has indicated the benefit will become fully realised in the September quarter. Measured against FY26 net operating cashflow of A$10.3m, an incremental A$7m pa represents an uplift of approximately two-thirds and is well timed as CTP funds the Palm Valley drilling program.

The improvement in cashflow will be reported as lower cash operating costs at Mereenie rather than as higher revenue.

Production Growth - Low-Risk

Palm Valley - leading the way

Development wells underwritten by contracted offtake

Joint Venture FID for two new Palm Valley wells (PV14 and PV15) was approved in April, following the signing of the new NT Government GSA. Site preparation and procurement were completed during the June quarter and drilling commenced on PV14 in late July. Both wells can be connected to existing production infrastructure without material additional works, and PV14 is expected to be supplying gas to customers from October.

PV full capacity to be restored

The PV plant's sales capacity is approximately 14 TJ/d (100% JV), against 5.8 TJ/d at the end of the June quarter. The 2 new wells aim to deliver at least 10 PJ of gas gross over the wells' operating lives. CTP has guided that the two wells should increase CTP's share of total gas production capacity across its three producing fields by circa 40%.

Capex fully funded

CTP's share of the capex for the 2 wells is estimated to be A$26m.

The program is fully funded and CTP secured an increase to its existing Macquarie facility in April, providing access to up to A$15m available for drawdown to 31 December 2026, with drawings repayable in equal quarterly instalments from March 2027 to December 2029.

At quarter end, total facilities were A$43.0m with A$25.5m drawn, leaving A$17.5m available. Cash at 30 June was A$20.4m, with an additional incremental A$1.75m of cashflow per quarter expected from the completion of the gas overlift at Mereenie.

Low risk profile

Palm Valley is a 616 km² structure with a long production history; the processing facility is in place and operating well below capacity, tie-in distances are short, and offtake from the new wells is contracted to 2034 with take-or-pay provisions and CPI escalation.

The principal risk is well deliverability. PV12 was successful, and as PV14 and PV15 are targeting similar geology, execution and deliverability risk should be considered to be low.

Mereenie remains under-utilised

Mereenie is producing approximately 26 TJ/d against plant capacity CTP estimates at around 40 TJ/d.

CTP has been studying a number of optimisation options including

- 3D seismic to identify opportunities to maximise gas recovery
- further development wells
- fraccing to enhance recovery and flow rates
- Stairway Sandstones.

The Stairway remains the most significant of these.

CTP has been considering drilling the shallower Mereenie Stairway Sandstones for some time. The drilling of WM29 and WM30 has shown very encouraging signs for the Mereenie Stairway. The 2 wells were drilled through the Stairway on the path to the target P3-producing interval and recorded consistent high-pressure gas shows. CTP is assessing the timing of a Stairway program. The Mereenie Stairway program aims to increase Mereenie reserves to enable CTP to both grow production and extend the asset life.

Dingo worth a re-look

Dingo continues to supply the Owen Springs Power Station at 4.23 TJ/d gross, close to contract maximums. CTP has flagged analysis of additional production wells, plant expansion and a connection to the Alice Springs pipeline to access the broader NT market, although in our view this ranks behind Palm Valley and Mereenie in the capital allocation queue.

Exploration: Portfolio Reshaped

Otway and Cooper Basins provide East Coast market exposure

CTP completed the acquisition of interests from ADZ Energy in January 2026, acquiring a 20% beneficial interest in PEP169 in the onshore Otway Basin in Victoria and a 49% beneficial interest in a Cooper Basin package in South Australia comprising PEL677 and PRLs 50–59, 61, 63, 65–72, 74, 75, 124 and 248. Tenement payments of A$11.2m were made in FY26.

Activity is underway with operator ADZ to progress an exploration well at Enterprise North in PEP169, and to reprocess seismic data to assist in optimising locations for drilling two Cooper Basin targets in PEL677 and the retention leases. These are conventional targets in mature, infrastructure-rich basins located within the East Coast gas market.

The move into the Otway and Cooper represents the most significant change to CTP's profile in several years.

Otway and Cooper gas, if successful, would be delivered into the market in which the AEMO forecast shortfall is concentrated and where prices are A$12–13/GJ.

The optionality of the 2 acquisitions is meaningful, and the entry cost was modest.

For further details on the Otway and Cooper Basins acquisitions please refer to our report **"At its Strongest Yet"** HERE

Amadeus sub-salt: Dukas relinquished, Mt Kitty retained

The Georgina Energy transaction will not proceed

In May, CTP terminated its conditional agreement to sell its interests in EP112 (Dukas) and EP125 (Mt Kitty ⁄ Jako Bore) to UK-listed Georgina Energy Plc (LSE: GEX) as the conditions precedent had not been satisfied by the due date, principally Georgina's requirement to hold £7m in cash immediately prior to completion.

Mt Kitty retained

CTP retains a 30% interest in EP125, the helium-rich sub-salt discovery with measured concentrations of 9% helium and 11.5% hydrogen. Operator Santos is required to drill the appraisal well by early 2028 under the minimum permit commitment schedule, and CTP continues to seek farm-out opportunities for the prospect.

Dukas relinquished

CTP has withdrawn from the EP112 joint venture with Santos in its entirety, following an assessment of the commercial prospects of the permit and the expected substantial cost of drilling the Dukas prospect and its relative prospectivity.

Dukas is a deep, high-pressure and high-cost well with a history of mechanical difficulty, and CTP's share of the cost would have represented a multiple of its annual exploration budget. The withdrawal removes an uncapped exposure while retaining the EP125 permit that holds the most prospective helium and hydrogen optionality, potentially on a carried basis should any farm-out succeed.

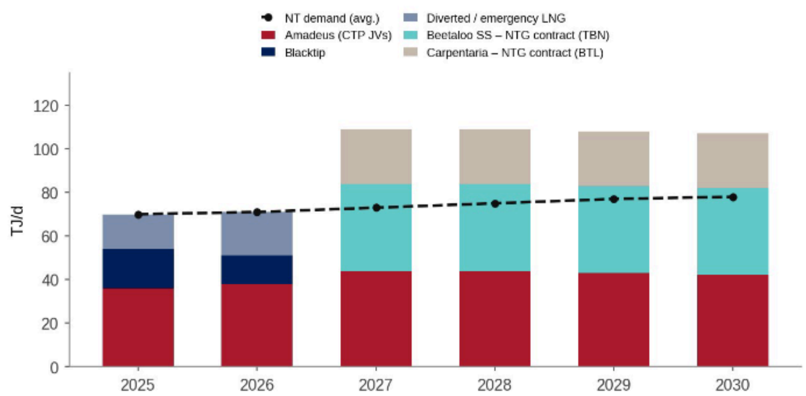
Elsewhere in the Amadeus, EP115 lies immediately to the north-west of Mereenie with limited exploration conducted to date, and preparation for seismic acquisition has been progressing. Mamlambo remains an oil target on trend with the Mereenie and Palm Valley fields. CTP is actively engaging with potential farm-in parties on both.

The NT Gas Market: Beetaloo Supply Approaches

The most material potential change to the NT gas market is that Beetaloo supply has moved from prospective to scheduled. Both pilot projects are funded and within months of first gas, and AEMO has reclassified both from "uncertain or anticipated" to "committed" in its 2026 Gas Statement of Opportunities.

The equity market is concerned with respect to CTP's position in the NT gas market and that Beetaloo volumes will create an oversupply in the NT and strand CTP's uncontracted production. However, there appears to be more opportunity than risk for CTP, as any new gas supply would first be applied to replace the circa 30TJ/d of gas being diverted from the Inpex LNG facility..

Figure 5: NT gas supply build-up vs demand, 2025–30 (TJ/d)*



Source: AEMO GSOO; company reports

** Note that the volumes indicated for Beetaloo in 2027 and beyond are the contracted full year rates with the NT Govt. and do not allow for any delays or part-year deliveries.*

Below we update the current status of Beetaloo projects.

Tamboran Resources: first gas targeted for 3QCY26

Tamboran (ASX/NYSE: TBN) completed the largest stimulation campaign undertaken in the Beetaloo Basin in July, stimulating, cleaning out and completing the SS-3H, SS-4H and SS-5H wells in the Northern Pilot Area.

The wells are to be tied into the Sturt Plateau Compression Facility, where construction is nearing completion (A$141m budget). TBN has described commissioning as imminent. First gas sales to the NT Government remain targeted for 3QCY26 under an unconditional, binding take-or-pay Gas Sales Agreement to supply 40 TJ/d at a fixed price escalated annually at CPI, for an initial term of nine years.

Five wells are expected to deliver plateau production of approximately 40 TJ/d.

Beetaloo Energy - Carpentaria on schedule for 4QCY26

Betaloo Energy's (ASX: BTL) construction of the Carpentaria Gas Plant progressed during the June quarter with key components installed on site, and remains on schedule for commissioning in 4QCY26. Clearing for the flowlines connecting the Carpentaria wells to the plant was completed during the quarter.

Carpentaria-5H commenced flow testing on 11 June, initially flowing above 14 TJ/d before settling to a 30-day average of 6.9 TJ/d with an exit rate of 6.7 TJ/d. BTL expects the Carpentaria Pilot Project production to be 9.5 TJ/d from mid-2026 increasing to 25 TJ/d, from CY2027

C-5H will be tied in alongside Carpentaria-2H and -3H ahead of first pilot gas sales.

For further details on Beetaloo Energy's progress please see our report **HERE**

Santos EP161: two wells planned for 3QCY26

Santos plans to drill the Jibera South 1H and Newcastle South 1H wells in 3QCY26. EP161 holds a 2C contingent gas resource of 1.88 Tcf. Santos continues to assess pipeline routes to connect its Beetaloo acreage to Darwin and to the East Coast market.

Implications for CTP - Still in the box seat

The NT market appears to be moving from shortfall towards balance rather than into oversupply.

The supply build-up as per committed NT supply increases from approximately 70 TJ/d in 2025 to around 120 TJ/d by 2027, against demand of approximately 75 TJ/d.

Composition is more important than the aggregate. The incremental volumes are pilot-scale, appraisal-stage supply from wells with limited production history, delivered through infrastructure that has not yet been commissioned, into a market where diverted LNG remains the expensive alternative. A delay to stimulation or commissioning would remove the projected surplus.

CTP - in production, contracted and supported by certified reserves

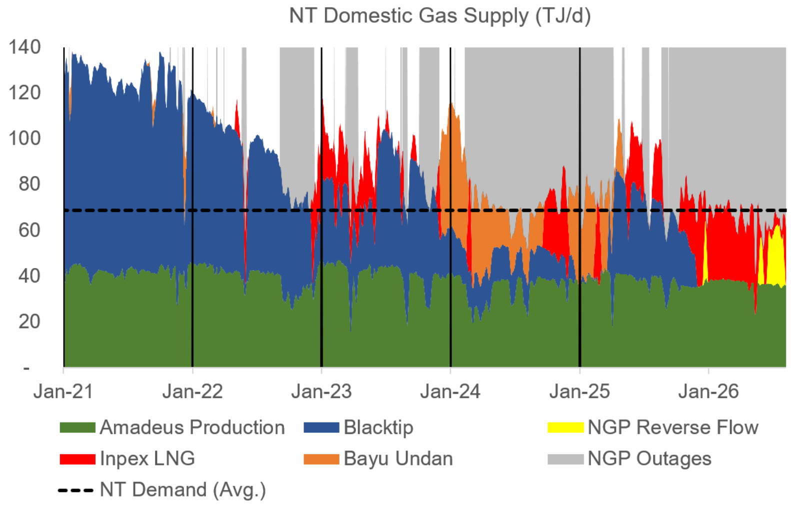
At 30 June 2025, 2P reserves were 73.1 PJ net to CTP, inclusive of 59.2 PJ of 1P, representing a 2P reserves-to-production ratio of approximately 15 years.

Beetaloo volumes are being sold as appraisal gas under "Beneficial Use of Gas" legislation, with reserves yet to be booked. For a customer assessing surety of supply over a ten-year horizon, these are not equivalent positions, and CTP has demonstrated the point by contracting 10.5 PJ through to 2034.

Figure 6 shows the historical supply and demand situation for NT gas. As can be seen, Blacktip ceased supplying the NT in late 2025, with the supply "emergency" shortfall in CY2026 being made up of Inpex LNG and reverse flow from the NGP (note the reverse flow NGP gas was as a result of Inpex maintenance shutdowns and industrial action in June and July). The Amadeus Basin has been a long term and steady supplier to the market.

Beetaloo will gradually replace both the Blacktip and the "emergency" supply into the NT.

Figure 6: NT Gas Supply and Demand



Source: CTP

Beetaloo supply could re-open the NGP - opportunity into East Coast

Beetaloo supply is also the mechanism by which the NGP could re-2open, which is a positive for CTP.

The pipeline has a 90 TJ/d nameplate capacity and requires approximately 20 TJ/d of minimum throughput for the nitrogen removal unit to operate and for the pipeline to be open. It has been closed for the majority of the past two years as the offshore Blacktip field could not sustain sufficient volume for the minimum 20 TJ/d minimum threshold. Beetaloo volumes of 40 to 65 TJ/d would comfortably restore NGP operations. Re-opening of the pipeline could once again provide CTP with a route to the East Coast market.

Customer contracting delay a risk

The more relevant risk is not oversupply but contracting behaviour, specifically that NT customers defer commitments in anticipation of Beetaloo volumes in an attempt to arbitrage a future price differential.CTP has addressed this directly. With 10.5 PJ contracted to the end of 2034 at a fixed CPI-escalated price, in addition to its existing six-year GSAs running to December 2030, the majority of firm production is already committed for CY27, with lesser annual volumes through to 2034.

Policy: The Domestic Gas Reservation Scheme

Status: settings announced, legislation pending

The Gas Market Review report was released on 22 December 2025 and the Australian Government accepted all 18 recommendations. On 7 May 2026, the Government announced the Domestic Gas Reservation Scheme, under which LNG exporters will carry a Domestic Supply Obligation equivalent to 20% of their annual LNG export volumes, commencing 1 July 2027 and pro-rated for the second half of that year. A draft Design Framework was released on 25 May 2026 and consultation closed on 30 June 2026. Legislation has not yet been introduced and final design settings remain subject to the outcome of that consultation.

Exporters will be required to physically supply gas to domestic buyers rather than merely offer it, with compliance linked to export approvals rather than to penalties alone. Export contracts entered into before 22 December 2025 are grandfathered, which excludes the long-term foundation contracts underwriting the existing LNG projects and materially limits the near-term volume effect.

The scheme is intended to replace the Australian Domestic Gas Security Mechanism (ADGSM), the Conditional Ministerial Exemption regime, the A$12/GJ price cap under the Gas Market Code of Conduct and the Heads of Agreement with the East Coast LNG exporters.

Existing regulations remain in force in the interim, and the ADGSM was not activated for either the June or September 2026 quarters.

Northern Territory: Darwin's obligations the key

The more consequential potential issue for CTP is the treatment of NT-based LNG exporters.

The Government has indicated a national scheme rather than an east-coast-only one, and has stated it will work with the Western Australian Government on alignment with WA's existing 15% reservation policy.

Darwin hosts two LNG facilities, and the NT has already relied on diverted LNG as an emergency backfill at prices understood to be in the range of A$17–18/GJ. If NT exporters carry a domestic supply obligation and are able to acquit it within the NT, the effect would be to convert that emergency supply into a standing obligation, adding competing volume to CTP's home market.

The draft framework does not resolve where obligations must be physically delivered, and the NT is not connected to the East Coast other than through the NGP, which has been closed for most of the past two years. **The Government has acknowledged that special provisions may be required for the NT market, which could not absorb 20% of LNG production and where the route to the East Coast markets is infrastructure-constrained.**

CTP's firm production is contracted to December 2030 and, under the new GSA, to the end of 2034, on take-or-pay terms. Any exposure is confined to uncontracted volumes from 2028, the same volumes exposed to Beetaloo supply.

Potential outcome - lower East Coast prices

The stated purpose of the scheme is to place downward pressure on domestic prices and to address the structural shortfall forecast (AEMO) in the southern states from 2029. To the extent it succeeds, it reduces the potential price CTP's could receive if Amadeus gas is piped to the East Coast or any future Otway and Cooper volumes. Grandfathering limits how much additional volume reaches the market before the early 2030s, and the forecast southern shortfalls are structural.

Conclusion - fairly neutral at this stage for CTP

The obligation for the gas reservation falls on LNG exporters. CTP does not export, and accordingly has no domestic supply obligation, no compliance cost and no exposure to the export approval linkage. The same applies to the Beetaloo pilot producers. The direct effect on CTP is nil. The indirect effects are more relevant.

The current status of the policy appears to be neutral for CTP's contracted cashflow, mildly negative for the pricing of uncontracted volumes from 2028, and mildly negative for potential East Coast pricing.

Offsetting this is the potential for CTP to become an emergency supplier for any domestic shortfall from the LNG projects. We will revisit the assessment when legislation is introduced and the treatment of NT exporters is clarified.

Valuation: Base-Case of A$0.24 (Previous A$0.22)

Stock Appears Substantially Undervalued

Our base-case valuation is shown in Figure 7. We have revised some of our cash and non-cash cost assumptions, taken into consideration the new PV GSA with the NT Govt (and the capex for the additional wells) and have included valuation for the Otway and Cooper Basin acquisitions. We have also adjusted net cash/debt to reflect the cost of the PV wells. Our overall valuation has increased to A$0.24/share. **Considering the low risks to price and volume, the stock remains trading at a significant discount and should continue to re-rate, in our view.**

Figure 7: CTP valuation summary

NPV	A$m Valuation Unrisked	Risking	A$m	Valuation A$ps	Previous Valuation	Change
Mereenie - OL4 & OL5 (25%)	83	100%	83	0.11	0.11	0.00
Palm Valley - OL3 (50%)	29	100%	29	0.04	0.02	0.02
Dingo - L7 & PL30 (50%)	50	100%	50	0.07	0.06	0.01
Enterprise North - PEP 169 (20%)	24	65%	16	0.02	0.02	0.00
Cooper Basin (49%)	3	100%	3	0.01	0.01	–
Total Operations	**188**		**180**	**0.25**	**0.22**	**0.03**
Net Cash / (Debt)	(7)	100%	(7)	(0.01)	(0.01)	0.00
Admin / Corporate / Other	(35)	100%	(35)	(0.05)	(0.04)	(0.01)
Exploration (risk-adjusted)	23	50%	11	0.02	0.02	(0.00)
Mereenie 2C gas (risked)	39	65%	25	0.03	0.03	0.00
TOTAL VALUATION	**208**		**175**	**0.24**	**0.22**	**0.02**

Source: MST

Amadeus Basin assets – undervalued

The Amadeus Basin assets - Mereenie, Palm Valley and Dingo - provide underlying production, earnings and cashflow which we believe is fundamentally undervalued by the market.

Core production assets (less corp. costs) contribute A$0.16 to base case

The core production assets of Mereenie, PV and Dingo (less corporate costs) make up A$0.16 of our A$0.24 valuation, suggesting that the market is placing a significant discount on assets that have locked-in contracts with one of the lowest-risk customers in the gas sector.

NT Government contracts underpin valuation – upside potential

The key underpinning of our valuation relates to the NT Government contracts. Further contracts with the NT Govt. would lead to an increase in our valuation.

Gas price – increasing assumption to A$10.00/GJ

While precise details on the NT Government gas offtakes are unclear for commercial-in-confidence reasons, CTP has been receiving average prices around or over A$10/GJ since the commencement of the contracts at the start of CY25. Our view is that the pricing will be around A$10/GJ for the NT Government contracts. We have reviewed our **gas price assumptions to A$10/GJ from A$9.75/GJ for our long-term price.** We consider this gas price forecast to be conservative and see further potential upgrades as the effects of this pricing come through over the next few quarters.

PV14 and PV15 wells - lifts valuation

We have been conservative in our valuation of Palm Valley. We have taken into consideration the capex for PV14 and PV15 (A$26m), but have conservatively modelled a 50% success rate (contribution from PV14 alone). This has lifted our valuation of PV, but substantial upside remains if both PV14 and PV15 are successful. The conservative valuation reflects the inherent risk of drilling, and we will await the results of the program before further adjusting our forecasts and valuation for PV.

The inclusion of the drilling program has lifted our PV valuation from A$16m (A$0.02 per share) to A$29m (A$0.04 per share). If we assume a 100% success rate for PV14 and PV15, our valuation for PV increases to A$42m or A$0.06 per share.

Valuation of Enterprise North (EN)

We have included in our valuation a preliminary estimate for EN. We use the same gas pricing assumptions as for the rest of the company's assets, and as the valuation is preliminary in nature, we have risked it at 65%. We assume first production in FY28 at 36 TJ/d, declining over 5 years.

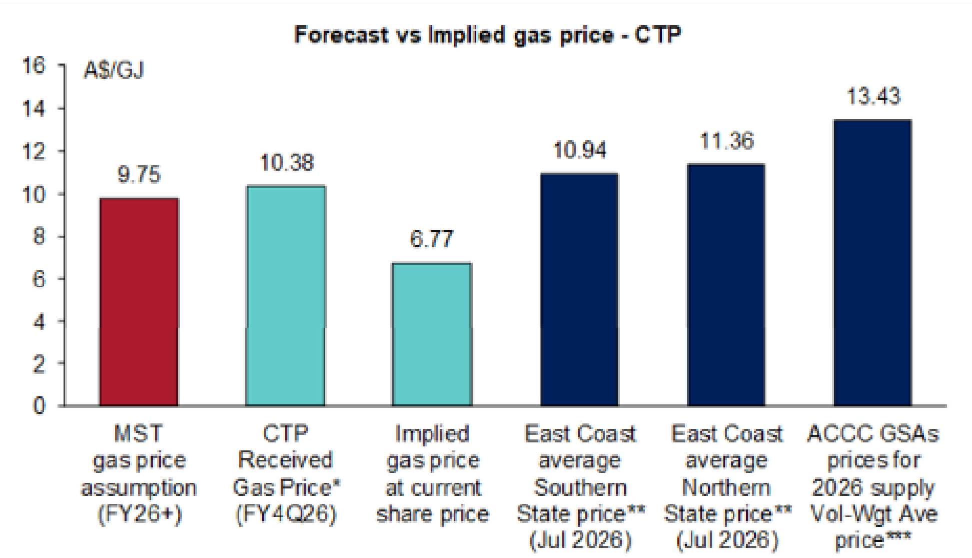
Valuation cross-check - more proof CTP undervalued

Implied gas price in CTP's share price A$6.77/GJ v A$10.38GJ received price

The current share price implies a gas price of A$6.77/GJ. CTP received an average price of A$10.38/GJ in the last quarter, and our forecast is A$10.00/GJ for FY27.

The current share price assumes that CTP's average gas price received will be some 25% less than that of the last quarter over the life of the assets.

Figure 8: Share price–implied gas price vs forecast and East Coast prices



*Source: SHA Energy Consulting, MST, CTP, *AEMO, **AEMO, ***Gas Market Emergency Price Order.*

Catalysts: upside potential driven by multiple sources

We see further upside potential to the share price and our valuation from multiple sources, which include:

- further GSAs for Mereenie gas
- higher cashflow from new NT Government contracts than we currently assume in our valuation
- additional capital returns via dividends or further share buy-backs
- increased production from Palm Valley from new wells
- exploration program – exploration and appraisal remain a source of potential valuation upside within CTP via the potential to increase reserves and thus increase production and/or the life of the assets. Key focus will be on the Otway Basin drilling and the Cooper Basin and the sub-salt exploration program if a JV partner can be found. Our valuation reflects minor upside from exploration
- establishment of helium production at Mereenie – we have not considered the potential value of helium in our valuation due to its early stage. The project is on hold and we await further information on costs and validity of extraction before taking this into our valuation
- a potential takeover due to CTP's value proposition.

Risks

Key risks to our valuation and to the share price include:

- lack of drilling success at Palm Valley
- further gas contracts for Mereenie not materialising
- lack of success from Otway and Cooper Basin drilling
- Mereenie Stairway development not proceeding
- sub-salt exploration not proceeding or lack of success
- government regulation affecting pricing
- the gas price, a key sensitivity for CTP's cashflow and valuation
- operational issues at existing assets.

Personal disclosures

Michael Bentley received assistance from the subject company or companies in preparing this research report. The company provided them with communication with senior management and information on the company and industry. As part of due diligence, they have independently and critically reviewed the assistance and information provided by the company to form the opinions expressed in this report. They have taken care to maintain honest and fair objectivity in writing this report and making the recommendation. Where MST Financial Services or its affiliates has been commissioned to prepare content and receives fees for its preparation, please note that NO part of the fee, compensation or employee remuneration paid has, or will, directly or indirectly impact the content provided in this report.

Company disclosures

The companies and securities mentioned in this report, include:

Central Petroleum (CTP.AX) | Price A$0.050 | Valuation A$0.240;

Price, target price and rating as at 13 August 2026 (not covered)*

Additional disclosures

This report has been prepared and issued by the named analyst of MST Access in consideration of a fee payable by: Central Petroleum (CTP.AX)

Other disclosures, disclaimers and certificates

Methodology & Disclosures

MST Access is a registered business name of MST Financial Services Limited (ABN 54 617 475 180 “MST Financial Services”), which is a limited liability company incorporated in Australia on 10 April 2017 and holds an Australian Financial Services Licence (AFSL 500 557). This research is issued in Australia through MST Access, which is the research division of MST Financial Services. The research and any access to it, is intended only for "wholesale clients" within the meaning of the Corporations Act 2001 of Australia. Any advice given by MST Access is general advice only and does not take into account your personal circumstances, needs or objectives. You should, before acting on this advice, consider the appropriateness of the advice, having regard to your objectives, financial situation and needs. If our advice relates to the acquisition, or possible acquisition, of a financial product you should read any relevant Product Disclosure Statement or like instrument.

ECM and corporate advisory services: MST Financial Services provides equity capital markets (“ECM”) and corporate advisory services through its capital markets division, MST Capital Markets (“MST Capital”). MST Capital provides these services to a range of companies including clients of MST Access. As such, MST Capital may in the future provide ECM and/or corporate advisory services and, accordingly, may receive fees from providing such services. However, MST Financial Services has measures in place to ensure the independence of its research division is maintained, including information barriers between its Capital Markets and Research teams. In addition, neither MST Access, nor any of its research analysts, receive any financial benefit that is based on the revenues generated by MST Capital or any other division of MST Financial Services.

Accuracy of content: All information used in the publication of this report has been compiled from publicly available sources that are believed to be reliable, however we do not guarantee the accuracy or completeness of this report and have not sought for this information to be independently certified. Opinions contained in this report represent those of MST Access at the time of publication. Forward-looking information or statements in this report contain information that is based on assumptions, forecasts of future results and estimates of amounts not yet determinable, and therefore involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of their subject matter to be materially different from current expectations.

Exclusion of liability: To the fullest extent allowed by law, MST Access shall not be liable for any direct, indirect or consequential losses, loss of profits, damages, costs or expenses incurred or suffered by you arising out or in connection with the access to, use of or reliance on any information contained in this report. No guarantees or warranties regarding accuracy, completeness or fitness for purpose are provided by MST Access, and under no circumstances will any of MST Financial Services’ officers, representatives, associates or agents be liable for any loss or damage, whether direct, incidental or consequential, caused by reliance on or use of the content.

General Advice Warning

MST Access Research may not be construed as personal advice or recommendation. MST Access encourages investors to seek independent financial advice regarding the suitability of investments for their individual circumstances and recommends that investments be independently evaluated. Investments involve risks and the value of any investment or income may go down as well as up. Investors may not get back the full amount invested. Past performance is not indicative of future performance. Estimates of future performance are based on assumptions that may not be realised. If provided, and unless otherwise stated, the closing price provided is that of the primary exchange for the issuer’s securities or investments. The information contained within MST Access Research is published solely for information purposes and is not a solicitation or offer to buy or sell any financial instrument or participate in any trading or investment strategy. Analysis contained within MST Access Research publications is based upon publicly available information and may include numerous assumptions. Investors should be aware that different assumptions can and do result in materially different results.

MST Access Research is distributed only as may be permitted by law. It is not intended for distribution or use by any person or entity located in a jurisdiction where distribution, publication, availability or use would be prohibited. MST makes no claim that MST Access Research content may be lawfully viewed or accessed outside of Australia. Access to MST Access Research content may not be legal for certain persons and in certain jurisdictions. If you access this service or content from outside of Australia, you are responsible for compliance with the laws of your jurisdiction and/or the jurisdiction of the third party receiving such content. MST Access Research is provided to our clients through our proprietary research portal and distributed electronically by MST Financial Services to its MST Access clients. Some MST Access Research products may also be made available to its clients via third party vendors or distributed through alternative electronic means as a convenience. Such alternative distribution methods are at MST Financial Services’ discretion.

Access & Use

Any access to or use of MST Access Research is subject to the Terms and Conditions of MST Access Research. By accessing or using MST Access Research you hereby agree to be bound by our Terms and Conditions and hereby consent to MST Financial Services collecting and using your personal data (including cookies) in accordance with our Privacy Policy, including for the purpose of a) setting your preferences and b) collecting readership data so we may deliver an improved and personalised service to you. If you do not agree to our Terms and Conditions and/or if you do not wish to consent to MST Financial Services’ use of your personal data, please do not access this service.