Amadeus Drilling Reset

Palm Valley (PV) Drilling - Third Option Flows Gas

The first exploration well in CTP's free-carried program, Palm Valley 12 (PV12), commenced in April. The primary target was the Arumbera Sandstone at a depth of 3,560m. The vertical well encountered fractures, drilling issues and increased costs and the deeper target was abandoned and replaced by a shallower target at a depth of ~2,060m, drilled laterally across the fractures in the Pacoota 2 and 3 Sandstones (P2 and P3). A combination of the presence of formation water and the absence of significant gas shows during drilling, led to a decision to curtail further drilling in the P2 and P3. **A third side-track operation into the P1 unit of the Pacoota Formation has flow tested 7 TJ/day**. **Subsequently, the well has reached a depth of 3,039m and is preparing for a further flow test. After flow testing is done, operations will move to complete the well as a producer.** At the flow test rate and the current spot of A$24/GJ, the well has the potential to generate ~$30m of gross revenue (CTP's 50% share).

PV Results Trigger a Strategic Review

The results and over budget costs of the PV drilling program has triggered a strategic review of CTP's asset portfolio, growth strategies and capital structure. The review will assess options for the portfolio of exploration, appraisal and production assets and look at further opportunities. The first phase of the review is expected to be completed by the end of October. The planned Dingo Deep exploration has been deferred, with focus on production enhancing projects at the Mereenie field to take advantage of the strong ECGM.

The Good News - Strong Spot Gas Pricing

In early May, CTP began delivering uncontracted gas into the spot East Coast Gas Market (ECGM), supplying 61 TJ of gas into spot markets through May and June at an **average delivered price of $34/GJ**, a significant premium to the average portfolio price in FY2022 of $6.73/GJe. CTP has also executed a new gas supply agreement with Shell Energy from the Mereenie Joint Venture over a one-year term commencing 1 January 2025. This commercialises a portion of its existing uncontracted production at a fixed price reflecting current strong market conditions. CTP is entering the ECGM at the right time, with the domestic market desperate for more gas and supply waning.

Annual Results – Profit from Asset Sales

CTP recorded a $21.8m profit for FY2022, which included a profit of $36m on the sale of assets. The operating loss was primarily driven by accounting for the higher costs of the PV exploration drilling. Stronger pricing and proceeds of the asset sale saw a reduction in net debt leaving CTP in a strong financial position.

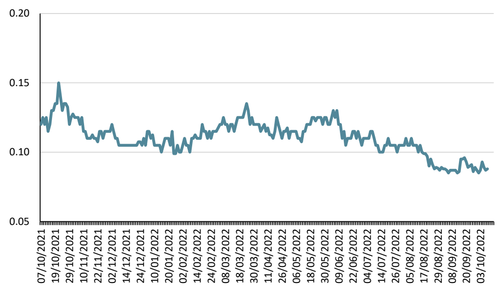
Central Petroleum (CTP) is the NT's largest onshore gas operator, with a portfolio of gas and oil assets focused on the Amadeus Basin and a significant coal seam gas (CSG) project in Queensland's Surat Basin. CTP has established a strong operational and exploration record. Its strategy is to unlock and commercialise the vast energy potential of the Central Australian basins to take advantage of a predicted tight supply/demand balance in the domestic gas market.

www.centralpetroleum.com.au

Stock	ASX: CTP
Price	A$0.091
Market cap	A$66m
Valuation (per share)	A$0.27 (previously A$0.31)

Next steps	
4Q2022	PV exploration / Strategic Review
3Q onwards	Range Gas production test

CTP share price (A$) – 1 Year



Source: FactSet.

Michael Bentley

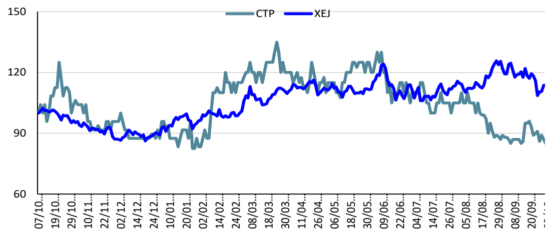
Valuation A$0.27/Share (Previous A$0.31) – Core Assets Provide Upside

Our risked valuation is A$0.27/share. The Amadeus Basin core production assets offer significant upside in valuation while there are still attractive exploration options. The structurally stronger ECGM is a driver to potentially increase our valuation, particularly with a discovery at the current P1 well. Key risks to the share price include lack of exploration success and poor production results at Range.

Exhibit 1 – Company summary (year-end 30 June)

Central Petroleum Limited (ASX:CTP)		
Share Price	A$/sh	0.09
52 week high/low	A$/sh	0.15/0.09
Valuation	A$/sh	0.00
Market Cap (A$m)	A$m	66
Net Cash / (Debt) (A$m)	A$m	–
Enterprise Value (A$m)	A$m	66
Shares on Issue	m	725.91
Options/Performance shares	m	18.15
Potential Diluted Shares on Issue	m	744.06

CTP Relative to XEJ 12 months



Ratio Analysis	2020A	2021A	2022A	2023	2024
EPS (A¢)	0.75	0.03	2.88	0.86	2.26
P/E (x)	10.8	345.4	3.8	10.4	3.9
EPS Growth (%)		-95%	8398%	-70%	163%
CFPS (A¢)	2.18	3.26	0.49	1.57	3.22
P/CF (x)	3.7	3.6	22.4	5.7	2.8
DPS (A¢)	–	–	–	–	–
Dividend Yield (%)	–	–	–	–	–
EV / EBITDA (x)	3.7	6.2	2.8	4.5	0.0
EV / boe (x)	52.7	66.6	98.8	70.1	0.0
EV / PJe (x)	8.8	11.1	16.5	11.7	0.0
FCFPS					
FCF Yield (%)					

Profit & Loss (A$m)	2020A	2021A	2022A	2023
Oil / Condensate Revenue	6	5	6	4
LPG Revenue	–	–	–	–
Gas Revenue	59	54	36	36
Total Sales	**65**	**60**	**42**	**40**
Operating Costs	(28)	(24)	(18)	(11)
Government Resource Taxes	(5)	(4)	(3)	(3)
Exploration & Development Expen	(5)	(8)	(21)	(4)
Other Net Income / Expense	1	(5)	33	(8)
EBITDA	**28**	**18**	**32**	**15**
EBITDAX	**33**	**26**	**16**	**18**
Depreciation & Amortisation	(16)	(13)	(7)	(6)
EBIT	12	6	26	8
Net Interest Expense	(6)	(6)	(4)	(2)
Pretax Profit	5	0	21	6
Tax Expense / Benefit	–	–	–	–
Net Attributable Profit	**5**	**0**	**21**	**6**
Reported Profit	5	0	21	6

Assumptions (Yr end Jun)	2020A	2021A	2022A	2023	2024
Brent Oil Price (US$/bbl)	50.40	53.75	90.54	86.7	80.6
Exchange Rate (A$1:US$)	0.671	0.747	0.725	0.700	0.700
Gas Price (A$/GJ)	5.34	5.71	6.99	6.63	7.28

Production	2020A	2021A	2022A	2023	2024
Gas (TJ/d)	31	27	13	15	20
Gas (PJ)	11.3	9.8	5.2	5.4	7.1
LPG (kt)	–	–	–	–	–
Oil / Condensate (mmbbl)	0.09	0.08	0.04	0.04	0.03
Total (mmboe)	**1.96**	**1.72**	**0.90**	**0.94**	**1.22**
Gas (mmboe)	1.88	1.64	0.86	0.91	1.19
LPG (mmboe)	–	–	–	–	–
Oil / Condensate (mmboe)	0.09	0.08	0.04	0.04	0.03
Year End Reserves 2P (mmboe)	**27.7**	**26.1**	**12.6**	**11.7**	**10.4**

Cash Flow (A$m)	2020A	2021A	2022A	2023
Pretax Profit	5	0	21	6
D&A & Other Non-Cash Items	10	24	(18)	5
Tax Paid	–	–	–	–
Cash from Operating Activities	**16**	**24**	**4**	**11**
Development Capex	(3)	(6)	(11)	(4)
Exploration Capex	(3)	(5)	(10)	(5)
Acquisitions/Other (Net of Sales)	8	0	28	–
Dividends Paid	–	–	–	–
Free Cash Flow	**20**	**16**	**21**	**8**
Cash Provided by Financing	(12)	(5)	(37)	(3)
Net Change in Cash	**8**	**11**	**(16)**	**4**

NPV	A$m	Risking	A$m	A$ps Valuation	Previous Valuation
Mereenie - OL4 & OL5 (25%)	65	100%	65	0.09	0.07
Palm Valley - OL3 (50%)	36	100%	36	0.05	0.03
Dingo - L7 & PL30 (50%)	42	100%	42	0.06	0.05
Project Range - ATP 2031 (50%)	102	25%	46	0.06	0.10
Total Operations	**245**		**245**	**0.26**	**0.25**
Net Cash / (Debt)	(1)	100%	(1)	(0.00)	(0.00)
Admin / Corporate / Other	(42)	100%	(42)	(0.06)	(0.04)
Exploration (risk-adjusted)	30	50%	15	0.02	0.02
Mereenie & Palm Valley 2C gas (risked)	40	50%	20	0.03	0.04
Dingo Deep & Palm Valley Deep (Prospective, Best)	47	25%	12	0.02	0.04
TOTAL VALUATION	**318**		**192**	**0.27**	**0.31**

Balance Sheet (A$m)	2020A	2021A	2022A	2023
Cash & short term deposits	26	37	22	26
Receivables	7	7	27	5
Inventories	3	2	4	6
Property, Plant and Equipment	108	54	54	52
Capitalised exploration	9	8	8	8
Intangibles and Goodwill	4	2	2	2
Other assets	4	64	5	5
Total assets	**160**	**174**	**122**	**105**
Creditors	5	10	14	8
Borrowings	71	67	31	23
Other liabilities	82	93	51	41
Total liabilities	**158**	**170**	**96**	**72**
Shareholder equity	2	4	27	33
Shareholder Equity + Total Liabilitie	160	174	122	105

Reserves and Resources As at 30 June 2022	Working Interest	1P Gas (PJ)	2P Gas (PJ)	1P Liquids (mmbbl)	2P Liquids (mmbbl)	2C Gas (PJ)	2C Liquids (mmbbl)
Mereenie (OL 4 / OL 5)	25%	30.5	39.2	0.4	0.4	45.6	0.1
Palm Valley (OL 3)	50%	11.3	12.7	–	–	6.8	
Dingo (L7)	50%	16.2	19.0	–	–	–	
Range (ATP 2031)	50%	–	–	–	–	135.1	
Total		**58.0**	**71.0**	**0.4**	**0.4**	**187.5**	**0.1**

Source: CTP, MST estimates.

PV Program - Third Option Flows Gas – Final Flow Test In Progress

CTP's drilling and appraisal program in 2022 was implemented to add resources and production. The free-carry program (as a result of the farm-out of 50% of production assets to New Zealand Oil and Gas and Cue Energy) commenced in April 2022 with the Palm Valley 12 (PV12) deep exploration well. The primary target was the Arumbera Sandstone at a depth of 3,560m. Gas shows were recorded, whilst drilling indicated the potential for a new, significant gas resource at Palm Valley Palm Valley in the lower P2 / P3 Sandstone, which lies immediately below the P1 Sandstone (the main gas producing zone at Palm Valley).

The vertical PV12 well intersected a major fracture zone within the lower P2 Sandstone which resulted in total lost circulation while drilling. In addition to the drilling difficulties, costs (particularly diesel) had increased since the plan was originally created. Having reached a depth of 2,335m, it was decided to replace the original PV Deep target with the shallower P2/P3 target at a depth of approximately 2,060m. The P2/ P3 target was not successful, with a combination of the presence of formation water and the absence of significant gas flows during drilling leading to a decision to abandon further drilling in the lower P2 and P3 sidetrack.

Third Option for PV Drilling – the Producing P1 Formation – Drilling Success Final Flow Test to be Run Prior to Completing as a Production Well

As planned, the fall-back option for the PV12 well was to drill a lateral well into the P1 formation. The P1 formation is the currently producing formation at Palm Valley. A successful PV12 lateral in the P1 formation will be tied into existing production facilities and gas production sold into strong Northern Territory and east coast gas markets.

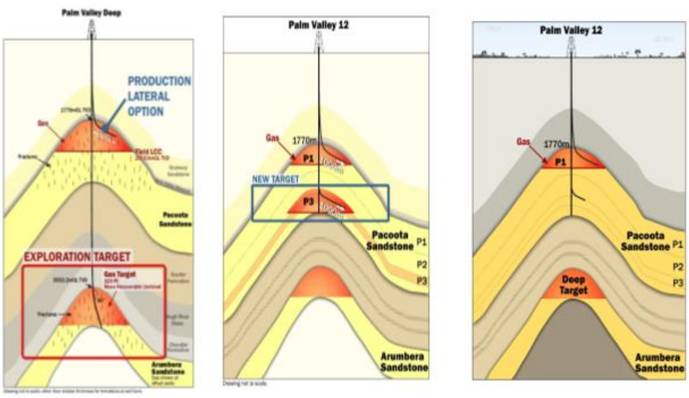
A second lateral well has been side-tracked to test the shallower Pacoota (P1) Sandstone, which is the current producing zone for the Palm Valley gas field. The lateral design is similar to the successful PV13 appraisal well drilled in 2019, which had a lateral extension of only 300m and has already produced approximately 5.7 PJs in three years.

The P1 well has flow tested 7 Tj/d, an encouraging result from a short lateral, and a brief test. **The flow rate equates to an annual production similar to that of the PV13 production well mentioned above**. The depth of the interim test interval was 1,870 metres to 2,598 metres and stabilized after 3 minutes. The test continued for 47 minutes. Only gas was recovered during the test, no water or oil was recovered, and no fracking conducted. The gas composition has not been analysed but is expected to be the same as the current production from the P1 interval, which around 98% hydrocarbons and minimal inerts.

Subsequent to the first flow test, the well reached a total depth of 3,039m and is undergoing preparation for a further flow test. After flow testing is done, operations will commence to complete the well as a gas producer.

The result from the P1 is positive for CTP and the gas can be delivered almost immediately into the spot ECGM (upon the Northern Gas Pipeline resuming see below). If we use the current spot gas price of A$24/GJ the well has the potential to generate $30.6m of gross revenue (CTP's 50%).

Exhibit 2 – PV12: Original deeps plan (LHS), PV12: Revised P2/P3 program (middle), Current P1 Program (RHS)



Source: CTP.

What Does the New Plan Mean for the Remainder of the Amadeus Free-Carry? Deferral of Dingo Deep Exploration Well

Original plan for Dingo Deep exploration well

Had the PV12 well not encountered the significant drilling issues requiring a major change of plans, a second deep exploration well at Dingo Deeps was planned. The plan for that well was:

- a deep exploration well with option to access existing production formation
- targeting a mean recoverable volume of 69 PJ (34.5 PJ net to CTP)
- a successful exploration test would have opened up a new play fairway in the basin

Exploration well deferred

The planned Dingo Deep exploration well has been deferred to prioritise capital for near-term production-enhancement activities at Mereenie or Palm Valley. The current ECGM provides clear incentive for development at Palm Valley or recompletions and development at Mereenie.

In contrast, the Dingo field is not currently connected to the ECGM as it supplies gas directly to a single customer in Alice Springs. Commercialisation options for success at Dingo Deep would have required construction of new surface infrastructure and modifications to the Amadeus Gas Pipeline and Alice Springs Pipeline to transport gas to the ECGM.

What's left of the free carry

Under the free-carry arrangements relating to the partial asset sale, the new joint ventures at Mereenie, Palm Valley and Dingo agreed to pay $40m of CTP's share of certain future exploration and development costs in those fields. At the end of June, $21.1m remained available for future use. It is expected that this will cover the completion of the PV12 well and some additional production-enhancing projects at Mereenie or Palm Valley (subject to JV approval).

PV Results – Trigger a Strategic Review

Following completion of the unsuccessful P2/P3 appraisal at Palm Valley, the CTP Board has engaged RBC to undertake a strategic review of the Company's asset portfolio, growth strategies and capital structure. The review will assess options for the Company's extensive portfolio of exploration, appraisal and production assets and examine opportunities to crystalise asset value. The first stage of the review is expected to be completed by the end of October.

The review will involve an extensive review of the portfolio and will include assessment of:

- The structure of the portfolio and potential sales of assets
- Opportunities given the current strong gas markets
- Optimisation of hydrogen and helium prospects
- Diversification
- Expansion into other basins
- The Range gas project

We consider that the strategic review will be extensive and may see substantial change to the company's portfolio, however we see that the share price performance may be relatively benign during the time of the strategic review.

Major Shareholder Joins the Board

Troy Harry has been appointed as a director of CTP effective 1 September 2022.

Mr Harry is a professional investor with a career in stockbroking and funds management and was the founder of Trojan Investment Management. Mr Harry is a substantial shareholder in CTP and has been instrumental in pushing for the Strategic Review of the Portfolio. Mr Harry will be a significant contributor to the strategic review.

Temporary Interruption to the Northern Gas Pipeline

There has been a temporary interruption to Northern Gas Pipeline (NGP). Eastbound gas transport on the NGP is currently suspended due to lower Blacktip production. Workovers and new drilling at Blacktip is expected to provide sufficient volume to re-open the NGP early in 2023.

In the meantime, various avenues are being pursued to enable NGP to reopen sooner, including expected new supply from PV 12 and diversion of Darwin LNG export gas into the NT market.

The pipeline interruption means that CTP cannot currently access the higher-priced east coast markets for its uncontracted production and the volume currently contracted to customers using the NGP has been re-directed to the NT market. We expect that this could impact production by up to 2.5 TJ/day (CTP's share), although this is likely to be mitigated as NT demand is expected to increase with the onset of warmer weather (increased gas fired power generation).

The Good News – The Gas Market

A Successful Entry to the Spot Market

In early May, CTP began delivering uncontracted gas into the spot East Coast Gas Market (ECGM), supplying 61 TJ of gas into spot markets through May and June at an **average delivered price of $34/GJ**. This generated over $2m revenue net to CTP through July 2022.

Entry into the high-priced ECGM spot market shows the potential revenue generation from any drilling success at PV12 (P1) and subsequent wells in the Amadeus. Although access to the ECGM is expected to be curtailed due to pipeline constraints for the balance of CY2022, ECGM spot and LNG netback prices remain strong as global energy markets continue to be tight.

CTP is entering the ECGM at the right time, with the domestic market desperate for more gas and supply waning.

Strong Gas Market Sees Uncontracted Gas Converted to Gas Sales Agreements

Central has executed a new Gas Sales Agreement (GSA) with Shell Energy for 0.91 PJs of gas supply over one year, commencing 1 January 2025.

The GSA is for firm gas supply, with take-or-pay provisions and a fixed price. The GSA commercialises a portion of existing uncontracted production. Ex-field pricing under the GSA reflects current strong market conditions.

Central is focused on bringing further gas to market from 2023 once it has completed its current PV 12 well and further development activity at Mereenie, and will be seeking to sell further uncontracted gas into the strong market.

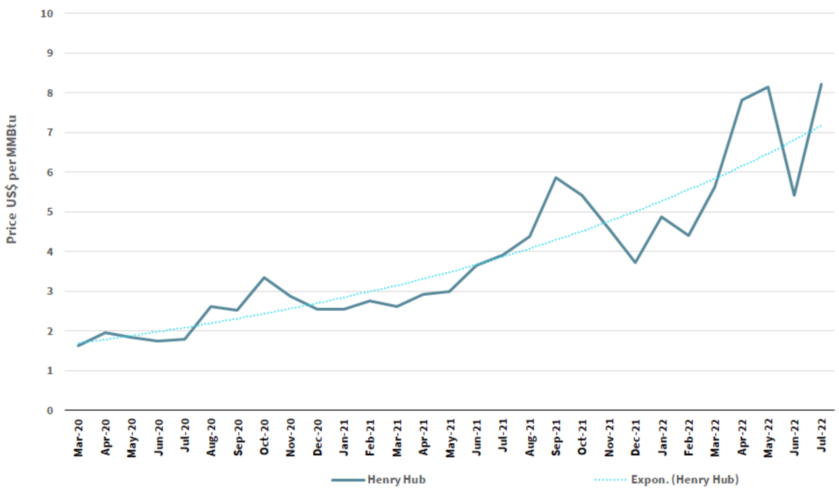
The agreement with Shell clearly shows the demand for gas in the ECGM.

Global Gas Market Continues to Be Challenged

The focus of the global gas market remains on supply to Europe. Russia's Ukraine invasion and the subsequent sanctions enforced upon Russia, as well as Russia's political movements with regards to cutting off supply, have exacerbated an already tight situation in Europe. The US continues to work to shore up gas supply for Europe through LNG imports from the US and allied nations, including Australia.

The US gas price has also increased substantially, sitting some 165% above the price a year ago (see Exhibit 3). The tight global supply situation, coupled with the US being viewed as a supplier of choice to Europe and with a relatively inelastic demand picture in the US, have combined to see a 'fear premium' being priced into the US gas price.

Exhibit 3 – US Henry Hub gas price, 2 years



Source: Factset.

East Coast Gas Market – Australian LNG Seen as Part of the Global Solution; Pressure Building on Local Supply

Spot prices have strengthened over the past 12 months, with LNG pricing increasing as Northern Hemisphere demand coincided with tightening supply. Local demand has increased from Queensland LNG projects looking to supply into a global market. Domestic East Coast demand has also increased markedly this winter as gas-fired electricity generation was called upon to replace coal-fired generation shortfalls, and government policy has been put in place looking at gas as a key energy component for domestic manufacturing and as a transition fuel into renewable energy sources.

From a supply point of view, the ACCC has forecast a potential domestic gas supply shortfall of 30 PJ pa as early as 2024 before a much greater potential shortfall of 358 PJ pa in 2032.

Spot pricing will influence future contract pricing

Large contracts in the Australian gas market are typically at negotiated prices and over terms of 3–5 years. The prevailing spot market price inevitably influences contract pricing arrangements. Continued high spot prices may lead to higher contract prices.

Domestic Gas Pricing – LNG Netback – Export Parity

What is the LNG netback price?

The LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port. When adjusted for these factors, an LNG netback price represents the price that a gas supplier would expect to receive from a domestic gas buyer so as to be indifferent to a choice between selling the gas to the domestic buyer and exporting it as LNG. LNG netback prices based on Asian LNG spot prices currently play an important role in influencing ECGM gas prices.

LNG netback price recently hit highest level since records began in 2016

Tightening global gas conditions, particularly in Europe, have put upward pressure on LNG prices, leading to a strong upward movement in the LNG netback price. The LNG netback price per the Australian Competition & Consumer Commission (ACCC) for September 2022 is A$56/GJ. October forward prices indicate a higher price of A$66.99/GJ.

What does this mean for the spot price of East Coast gas?

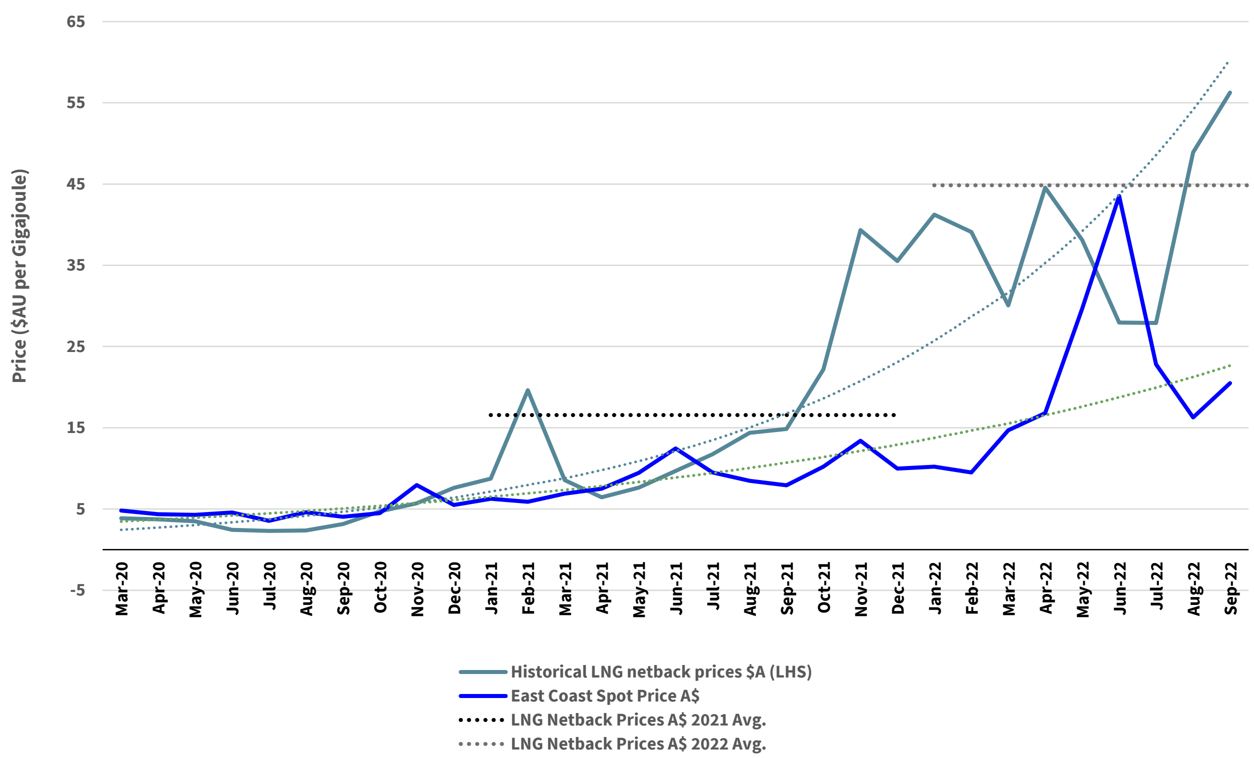
The confluence of global supply side issues and increasing demand, coupled with a tight domestic supply demand scenario, has naturally put upward pressure on domestic pricing. An added recent local dynamic is the emergence of shortfalls in the dispatchable electricity generation capacity and demand brought on by downtime in key base load electricity plants, a gap that is projected to widen with scheduled retirement of coal-fired plants.

The spot (Wallumbilla netback) ECGM has seen significant pricing moves in CY2022, having begun the year around A$10/GJ, with pricing at the end of September at over $20/GJ. Prices peaked at over A$40/GJ in June.

The Australian government has proposed an extension of the Australian Domestic Gas Security Mechanism (ADGSM) until 2030 and may also review the policy aimed at boosting domestic gas supply. The review of the ADGSM, created by the previous government to ensure domestic gas supply, comes amid growing criticism about the fact that Australia exports the majority of its gas production, along with the recent electricity shortages in the eastern states.

Exhibit 4 shows the current ECGM spot vs LNG netback prices. It shows a distinct breakout of LNG netback prices from late 2021 and spot price movement from February 2022.

Exhibit 4 – LNG netback prices vs prevailing spot ECGM prices



Source: ACCC, AEMO STTM.

A Strong End to the Financial Year – Spot Sales Drive Higher Cash

Financial Results for FY2022

- Higher Gas Volumes and Prices
- Profit from Sale of Assets
- Higher Exploration Expense from PV Drilling

Exhibit 5 – MST Estimates v Actual

Profit & Loss (A$m)	FY2022 MST Est	FY2022 Actual	Difference	Notes
Total Sales	**42**	**42**	**(0)**	
Operating Costs	(22)	(21)	1	
Exploration & Development Expenses	(10)	(22)	(12)	MST accounted for PV drilling expense in Balance Sheet not P&L
Other Net Income / Expense	36	33	(3)	
EBITDA	**47**	**32**	**(14)**	
EBITDAX	**56**	**54**	**(2)**	
Depreciation & Amortisation	(7)	(7)	(0)	
EBIT	40	25	(15)	
Net Interest Expense	(4)	(4)	(0)	
Pretax Profit	36	21	(15)	
Tax Expense / Benefit	–	–	–	
Net Attributable Profit	**36**	**21**	**(15)**	

Source: MST estimates / CTP

Entry into the ECGM Spot Market – A Game Changer for CTP

In early May, CTP began delivering uncontracted gas into the spot East Coast Gas Market (ECGM). Through May and June, it supplied gas into spot markets at an average delivered price of $34/GJ, generating over $2m revenue net to CTP.

The ECGM spot sales make up a small portion of the total sales portfolio (some 15% of gas production), but they have helped boost overall revenues by 19% from the last quarter and contributed to the $21.6m cash balance at 30 June.

A Quick Look at the Volumes, Prices and Financials

Volumes – maintenance on the pipeline softens production in the last quarter

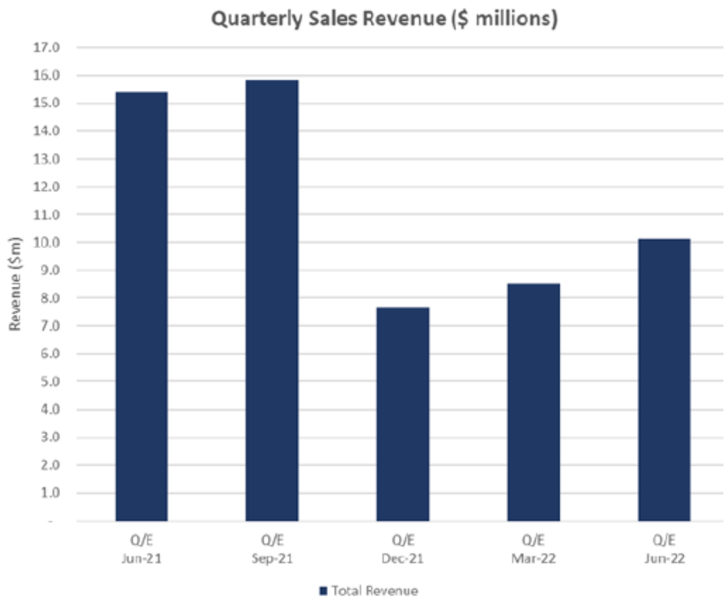
Scheduled maintenance on the Northern Gas Pipeline restricted gas sales during the quarter, which resulted in sales volumes being 6.5% lower than the previous quarter. Firm long-term gas supply contracts in the Northern Territory accounted for 85% of June-quarter volumes, with the balance being supplied into the high-demand spot ECGM.

Prices and revenue – spot prices turbo charge the last quarter

Sales revenue for the June quarter was $10.1m, up 18.7% from the March quarter. Unit sales prices across the portfolio increased by 26.9% from the March quarter to an average of $8.49/GJ, reflecting CTP's new access to high-priced spot ECGM and higher oil prices.

CTP's $42.2m full-year revenue was lower than FY2021 due to the lower ownership interests from 1 October 2021, but after adjusting for that impact, **revenues were 12.7% higher than FY2021 on a like-for-like basis**. This was achieved on lower like-for-like volumes (down 2% on FY2021), with the realised oil price 76% higher in FY2022 and the average gas portfolio price up 9% on FY2021.

Exhibit 6 – Quarterly sales for FY2022 ($m)



Source: CTP.

Financial position – balance sheet strengthening

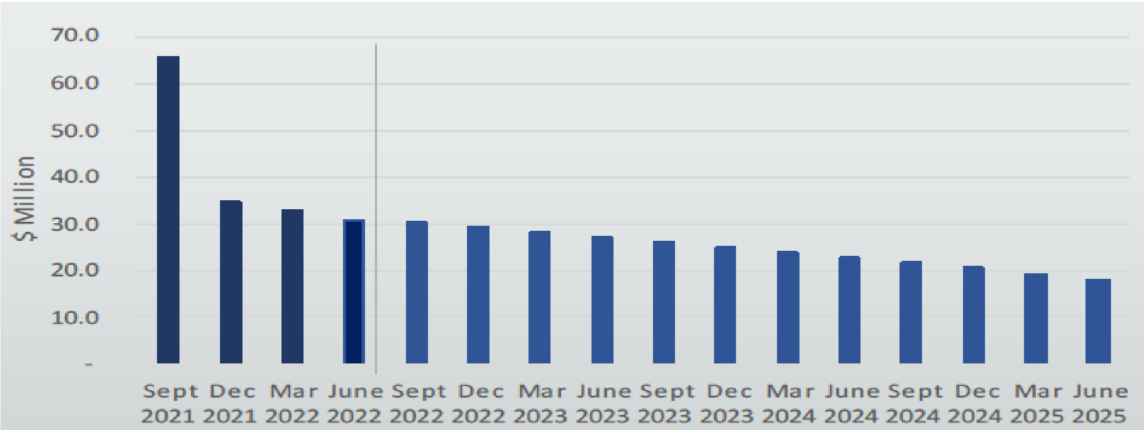
Cash and debt

Cash balances were $21.6m at the end of the quarter, up from $18.9m at the end of March. The net cash inflow from operations for the quarter was $5.5m after exploration costs and finance costs. Cash receipts from customers during the quarter were $10.8m, benefitting from strong oil prices and spot gas sales into the higher-priced ECGM.

Net debt was $10.2m at 30 June, down from $15.0m at the end of March due to higher cash balances.

CTP's strong quarter of cash flow generation allowed further pay down of debt.

Exhibit 7 – Debt balance ($m) – CTP's forecast paydown



Source: CTP.

Extension of debt facility

In April, CTP extended its $32.8m loan facility by three years, with the partially-amortising facility now expiring on 30 September 2025. The terms remain substantially the same as the existing facility.

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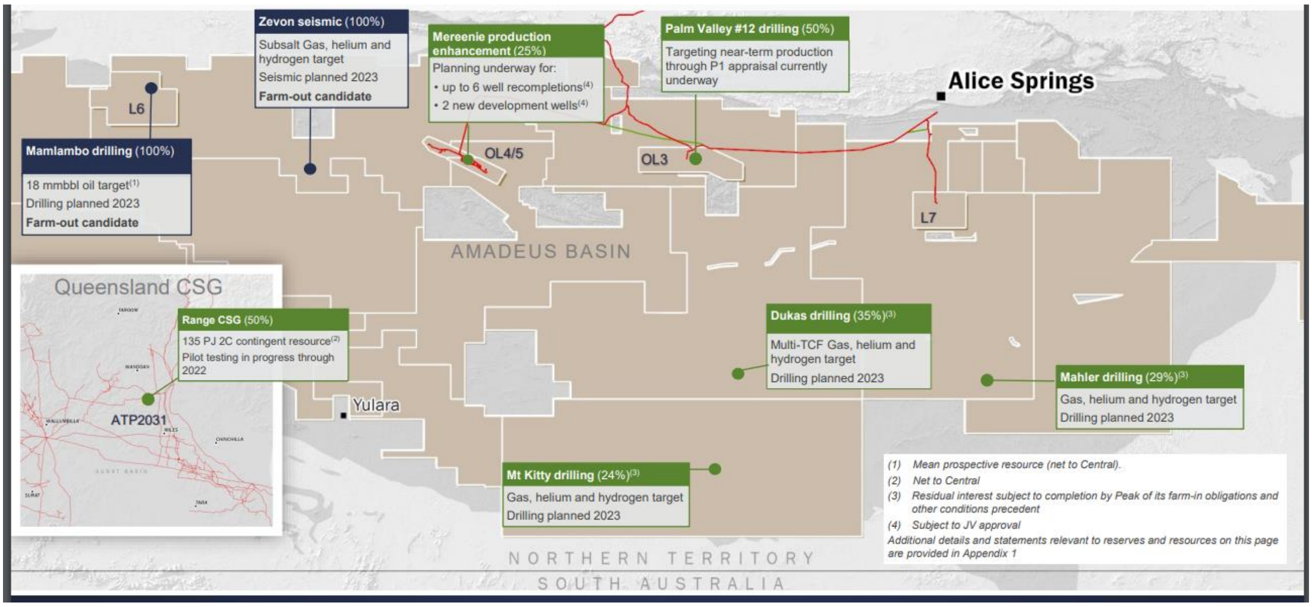
Other Key Appraisal and Exploration Projects – An Update

Exhibit 8 – CTP Portfolio Near Term Activity



Source: CTP.

Range CSG Project – Production Testing Underway

CTP's 50%-owned Range CSG Project aims to bring production into the ECGM. The Range CSG Project contains 135 PJ of 2C contingent gas resource (net to CTP). Gas production from the Range CSG Project is reserved for domestic use.

The initial pilot program encountered lower-than-expected initial water rates which led to an extended dewatering period. The four previous exploration wells had intersected circa 25% more net coal than the pilot wells (33m vs 26m). It is well understood with CSG in the Surat Basin that the coals show some variability and that selection of the position of the wells is important. Two new pilot wells were drilled in April 2022 and have been spaced at a greater distance (circa 2km) from the original pilot and averaged 29m of net coal.

Extended production test of the new pilot step-out wells (Range-9 and Range-10) commenced in early April, with water production controlled to allow for a gradual drawdown. One of the original pilot wells, Range-6, was returned to production and production testing of the three wells continues. Gas flows have been gradually increasing and the pilot wells are currently producing gas at an aggregate 40,000 scfd. Early gas flows indicate good gas saturation, although the relatively low water rates suggest that a longer dewatering period will be required.

The pilot wells are intended to provide key information regarding reservoir productivity (initially via water rates), gas desorption (when gas is first produced), zonal contribution (how much each coal seam is contributing) and the initial production profiles of gas and water ramp-up. Recent data swaps with a neighbouring permit could provide additional technical insights.

Progress on Sub-Salt Drilling in 2023: Farm Out to Peak Helium; Helium and Hydrogen on the Radar

Three wells to be drilled by Peak Helium, with costs carried for two

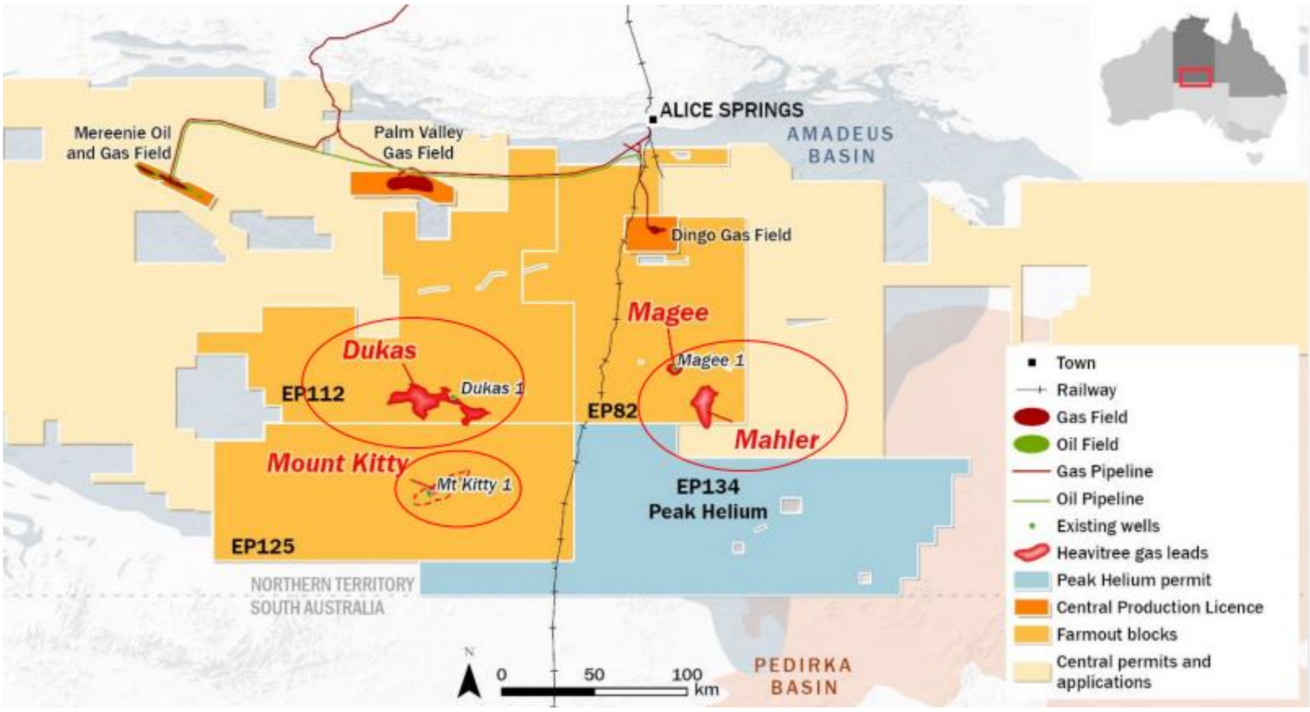
CTP has farmed out interests in a number of its sub-salt permits to Peak Helium[1]. Peak has committed to drilling at least three wells, carrying CTP's costs for two of these. Details are as follows:

- EP82 (includes Magee/Mahler): Peak will receive a 31% interest in EP82 from CTP, reducing CTP's interest in this tenement to 29% from 60%. In return, Peak will fund CTP's share of costs (up to a cap of $20m gross well cost) for a new exploration well at the Mahler prospect, targeting natural gas and helium.
- EP112 (includes Dukas): Peak will receive a 10% interest in EP112 from CTP, reducing CTP's interest in this tenement to 35% from 45%. There is no funding/carry of CTP's costs in this permit. Peak has, however, committed to the timely drilling of the highly prospective Dukas exploration well.
- EP125 (includes Mt Kitty): Peak will receive a 6% interest in EP125 from CTP, reducing CTP's interest in this tenement to 24% from 30%. In return, effective 1 October 2021, Peak will fund CTP's share of costs (up to a cap of $20m gross well cost) for a new exploration well, or a re-entry of the existing suspended exploration well, at Mt Kitty, which will target helium, hydrogen and natural gas.

Completion of CTP's farmouts to Peak is subject to the usual conditions precedent for a transaction of this nature including Joint Venture, Central Land Council, royalty holders and NT regulatory approvals. Peak has finalised Stamp Duty arrangements with the NT government and progress towards completion has continued, with the satisfaction date extended to 30 November 2022.

Santos, as operator of these permits, has commenced detailed planning, approvals and procurement for the 2023 drilling program.

Exhibit 9 – CTP's Sub Salt Plays



Source: CTP.

[1] Peak Helium (Amadeus Basin) Pty Ltd is a private company with a focus on exploring, developing and commercialising discoveries of helium to create an Asia Pacific and international market leader. Peak Helium currently holds a 100% interest in EP134, Northern Territory, Australia.

Valuation: Current Operations Generate Value, Exploration Program Presents Significant Upside

Base-Case Valuation of A$0.27 (Previous A$0.31)
Core ProductionAssets A$0.20 Any Exploration Success a Bonus

The Amadeus Basin assets provide underlying production, earnings and cash flow from which CTP can unlock substantial upside potential. We believe this upside is being potentially mis-priced by the equity market. In addition, the Range CSG Project has a significant contingent resource in a basin that has been proven to be able to be brought to production rapidly.

Our valuation is A$0.27/share (previous $0.31). Our valuation includes the strong ECGM fundamentals as the gas price received over time by CTP rolls contracts into higher prices as well as delivering uncontracted gas into higher priced spot markets. We have not included any volumes from any success at the P1 lateral drilling at Palm Valley, which would be delivered into the spot market.

Valuation methodology: accounting for uncertainty by applying a risk factor to each asset

Valuing oil and gas assets, particularly in the exploration and appraisal stage, is quite a subjective process. A number of uncertainties are at play, as significant test and appraisal works are still to be completed.

We include a risk factor in our valuation of each of the individual assets. We use an individual risk weighting for each asset, allowing us to account for these developments as well as the less certain opportunities for some of the other assets. Production assets are risk weighted at 100% (see Exhibit 10).

Exhibit 10 – Base-case valuation summary – fully diluted (A$ per share)

NPV	A$m	Risking	A$m	A$ps Valuation	Previous Valuation
Mereenie - OL4 & OL5 (25%)	65	100%	65	0.09	0.07
Palm Valley - OL3 (50%)	36	100%	36	0.05	0.03
Dingo - L7 & PL30 (50%)	42	100%	42	0.06	0.05
Project Range - ATP 2031 (50%)	102	45%	46	0.06	0.10
Total Operations	**245**		**245**	**0.26**	**0.25**
Net Cash / (Debt)	(1)	100%	(1)	(0.00)	(0.00)
Admin / Corporate / Other	(42)	100%	(42)	(0.06)	(0.04)
Exploration (risk-adjusted)	30	50%	15	0.02	0.02
Mereenie & Palm Valley 2C gas (risked)	40	50%	20	0.03	0.04
Dingo Deep & Palm Valley Deep (Prospective, Best)	47	25%	12	0.02	0.04
TOTAL VALUATION	**318**		**192**	**0.27**	**0.31**

Source: MST estimates.

Our valuation has decreased from $0.31 to $0.28 per share. We have increased the risk (decreased the probability) of the Range project due to the slower gas ramp up from the pilots. We have also increased the risk (decreased the probability) on the exploration portion of our valuation given the PV12 results.

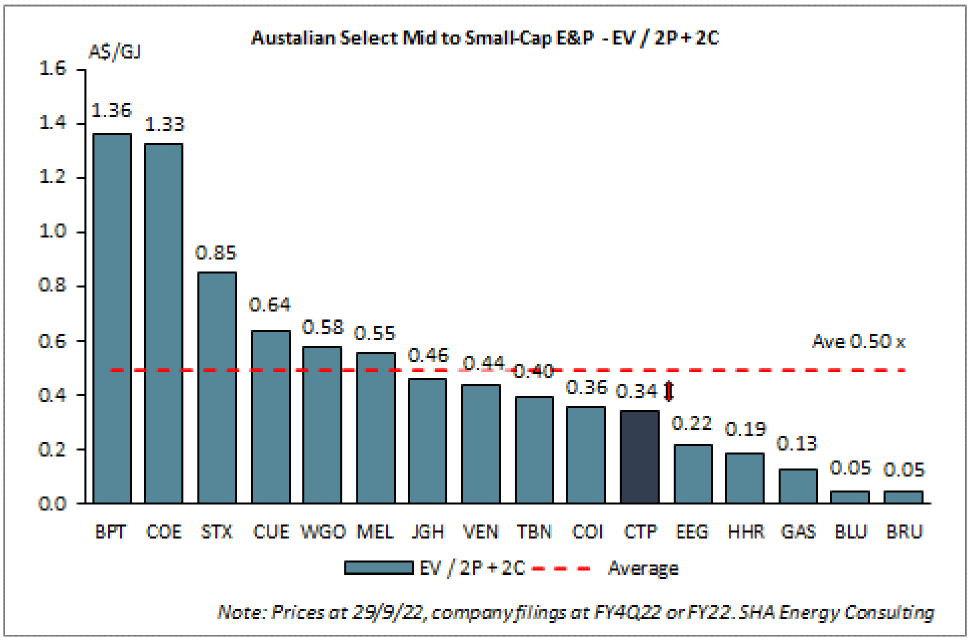
Enterprise Valuation to Resources:
A Cross Check on our Valuation Supports our View that CTP Is Undervalued

An additional check on our valuation is to observe how the market values the reserves and resources of CTP and its ASX-listed peers (see Exhibit 9), using EV/2P+2C. This yields a lower alternative valuation than our NPV-based method, but does reflect upside to the current share price, particularly if the 2P reserves base can be expanded.

This valuation metric shows the relative value the market attributes to the company's reserve and resource base. CTP is valued significantly below its peer average, with CTP's EV/2P+2C of 0.34 comparing to the average of 0.50. The peer average would see CTP valued at **A$0.17 vs. the current share price of A$0.09 and our valuation of A$0.27.**

The market has placed the highest value on the reserves and resources of Beach Petroleum, Cooper Energy and Strike Energy, both of which have a significantly larger 2P reserves base than both CTP and the peer group. The 2P reserves base is given a higher relative value by the market than 2C resources.

Exhibit 9 – Select Australian EV/Resources multiples



Source: MST estimates, company releases, SHA Energy.

Significant Upside Potential Remains, Driven by Multiple Sources

We see strong upside potential to our base-case valuation. CTP has multiple sources of potential upside valuation over time. Potential drivers of future upside include:

- exploration program – despite the disappointing result at PV exploration remains a strong source of potential value, potential to increase reserves and increase production and/or life of assets – short term success at P1 could be delivered rapidly into the spot market.
- construction of Amadeus to Moomba Gas Pipeline (AMGP) – significantly reducing gas transport costs and increasing net received gas price
- further increase in east coast gas price
- Range CSG Project development – despite slower gas ramp up, rapid development potential remains, and success would add significant cash flow
- helium and hydrogen exploration success.

Key risks

- The disappointing exploration results at PV have shown the risk in exploration, and it remains a key risk to valuation upside.
- Extended delays to the Northern Gas Pipeline (NGP)
- Delays in the progress of the AMGP would delay the upside potential from increased volumes and lower costs.
- CTP's cash flow and valuation are sensitive to the gas price.
- Operational issues at existing assets would reflect poorly on management and decrease cash flow and valuation.
- The Range Gas Project in the Surat Basin has strong potential for development. Any lack of progress would be a risk to the valuation and share price.

Appendix 1: Resources and Reserves

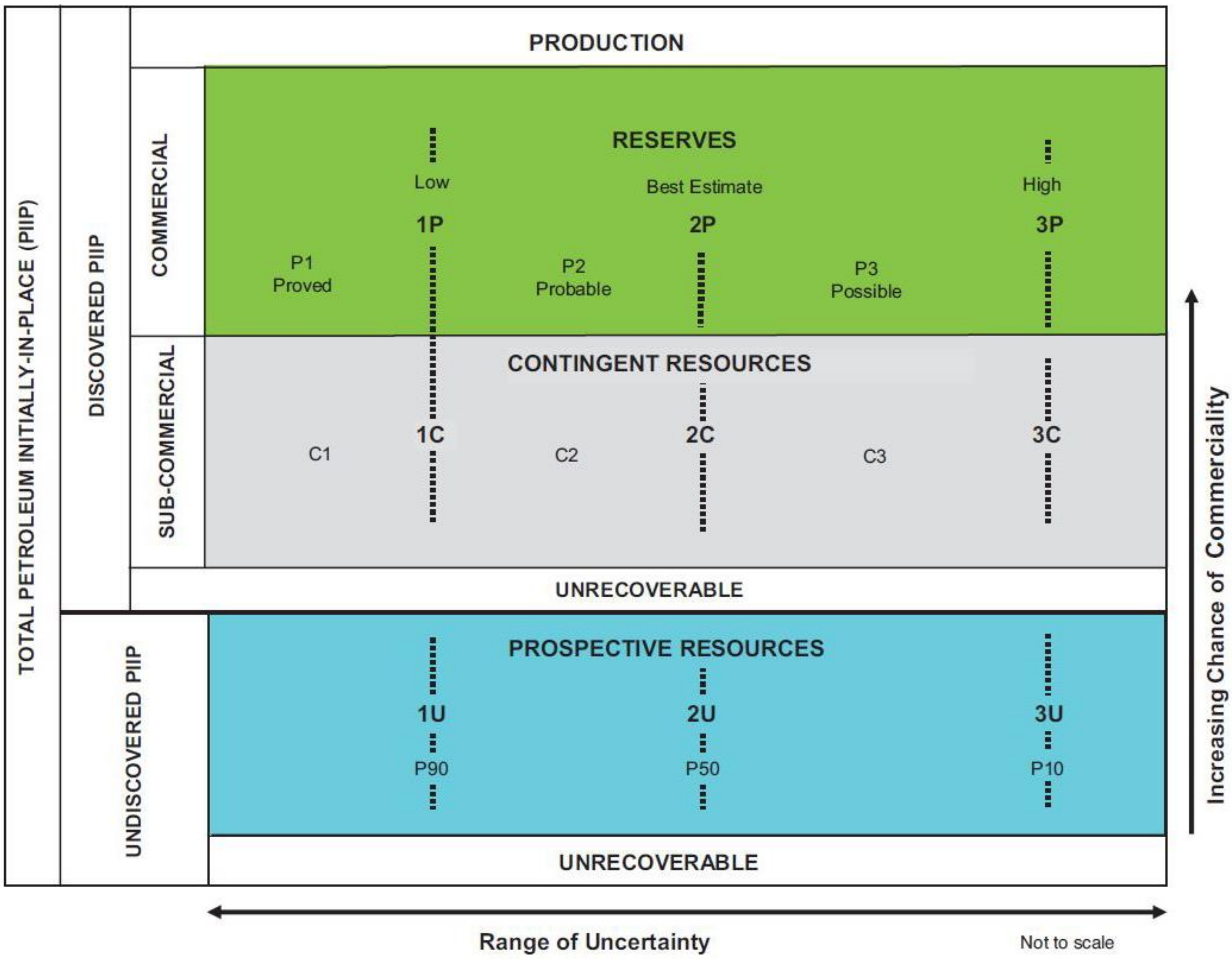
Exhibit 10 shows the three categories into which estimated quantities of potentially recoverable petroleum can be placed: Prospective Resources, Contingent Resources and Reserves. Within each category, three estimates are designated to describe the range, with greater certainty at the low end and less certainty at the high end.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but where the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. The categories within Reserves, in decreasing certainty, are Proved, Probable and Possible.

Exhibit 11 – Resources and Reserves



Source: CTP.

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