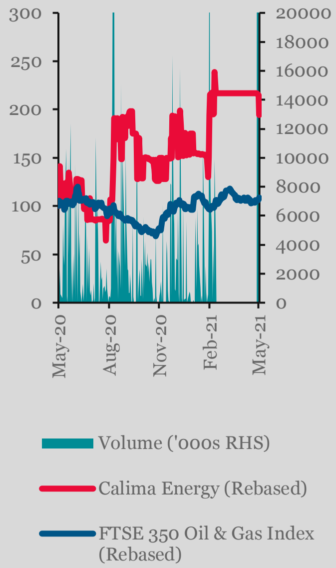
Calima Energy

Strong cash generation with large resource upside

GICS Sector	Energy
Ticker	ASX:CE1
Market cap 12-May-21 (US$mm)	74
Share price 12-May-21 (AUD c)	0.9

NAV summary (AUD c/sh)

Asset	Unrisked	Risked
Core NAV	1.13	1.02
Development	3.02	1.33
Exploration	1.86	0.07
Total NAV	**6.0**	**2.4**



We initiate coverage on Calima with a risked NAV of AUD 2.4c/sh

Calima is an Australian listed E&P company, focused on Canada, an established energy market with a supportive energy policy. It has exposure to a large-scale wet gas play in the Montney and - with the completion of its C$61.5mm acquisition of Blackspur on 3rd May - low-cost, high return, oil-weighted assets in Alberta. Calima capitalised on the opportunity to acquire Blackspur as the company was struggling in 2020 under a heavy debt burden as COVID hit and oil prices crashed. As well as striking a good deal, Calima has changed its equity story through this transaction to be more aligned with current investor appetite. Calima now gives investors exposure to oil prices and, longer-term, North American gas prices, which we expect to rise. The company offers a combination of value, growth and strong shareholder return potential given its high cash flow. The management team are largely incentivised through equity and strongly aligned with shareholders.

Blackspur acquisition: strong growth within cashflow from existing reserves

The merger with Blackspur creates a mid-tier, ASX-listed company, with strong cash flow from high return conventional oil assets that have been undercapitalised for several years. Blackspur's assets offer organic growth through the drill-bit with >20 years reserve life. It has some of the lowest cost (<US$15/boe capex plus opex) and highest return drilling locations (>500% IRR at current prices) available globally. We expect >40% production growth in 2022 whilst generating ~15% FCF yield. C$200mm has been invested in the assets historically, versus an acquisition price of ~C$60mm. We see a risked 2P NPV10 of C$168mm for Blackspur, ~175% higher than what Calima paid. There is further upside from an acceleration of production and bettering the well production type curves. Relative to Canadian peers (which are +180% YTD), Blackspur has stronger production and cashflow growth in 2022, a much healthier balance sheet, a higher reserve life and a lower cost base.

Montney: large resource with exposure to improving Canadian gas pricing

Calima has been a successful explorer in the Montney, proving that its concept worked, extending the play beyond the expected boundary and achieving better than expected well results. However, the market went against it given an oversupply of Canadian gas. More recently North American gas prices have markedly improved and corporate activity in the Montney has picked up again. Following the Blackspur transaction, Calima has the luxury of time to look to monetise the significant ~200mmboe of discovered resource, which could take the company to the next level. The Montney is one of the most competitive unconventional plays in North America given low cost, high productivity and liquids rich wells combined with attractive fiscal terms.

Catalysts: Blackspur well performance; Montney and LNG activity

The key catalysts are continued well type-curve outperformance from its current drilling campaign and an acceleration of drilling to bring forward production targets, potentially with the short pay out period being hedged. We expect some small bolt on acquisitions around the existing assets. In the Montney, we expect continued corporate activity and progress of LNG projects to increase the market value of the play. We also see the potential for the company to increase the size of the debt facility and/or increase the term.

Valuation: ~170% upside to our risked NAV

Our primary valuation methodology is a risked NAV of AUD 2.4c/sh at US$60/bbl Brent. There is also 13% upside to our Core NAV of AUD 1.02c/sh, which only includes the 1P reserves. On a multiple basis, we estimate that Calima is trading on 2022 EV/CFFO of 2.4x. Using the ~C$25mm valuation for the Montney implied pre-Blackspur, sees it trading on just 1.8x EV/CFFO in 2022, versus the peer group on 4.4x. On operational metrics, we see Calima trading on EV/2P reserves of C$4.6/boe and on a flowing barrel basis on $21k per boe/d in 2022. We expect C$24/boe of post-tax cashflow per barrel in 2022. Cash distributions will be driven by market conditions and achieving sustainable production of >5kboe/d, which we expect in 2022.

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Investment Case

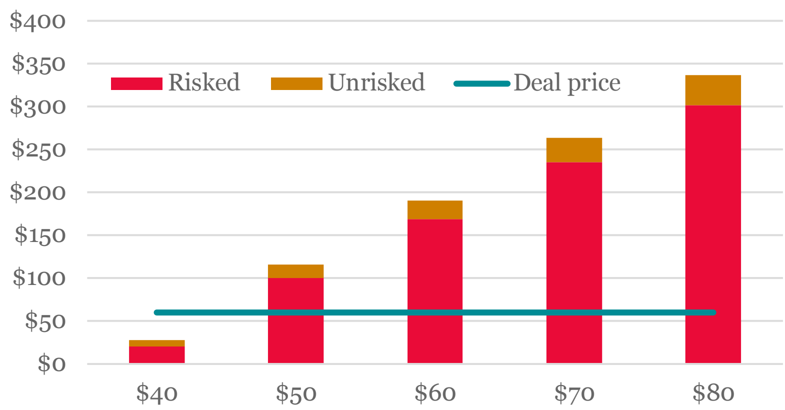
Company overview – Calima (ticker "ASX:CE1") is an Australian listed E&P company with its core assets in Canada. It was formed in 2017 by a team of leading global explorationists to test a play concept in the Montney, which is a leading resource play in North America. It has a large land position of ~60k acres, where it has successfully derisked almost 200mmboe of contingent resource. Its recent acquisition of private Canadian company Blackspur has added low-cost, oil-weighted production, significant cash flow generation and plenty of high return growth potential.

Investment case highlights – Our risked NAV on Calima of 2.4c/sh implies 170% upside. Calima has near-term oil price exposure from the Blackspur assets and longer-term gearing into the energy transition through its Montney position. The company offers a combination of value, growth and shareholder return potential. It offers organic growth through the drill-bit with >20 years reserve life. It has some of the lowest cost (<US$15/boe capex plus opex) and highest return drilling locations (some >500% IRR at current prices) available globally. We expect >40% production growth in 2022 whilst generating ~15% FCF yield based on the current price. Calima has a strong balance sheet and minimal decommissioning liabilities relative to its peer group and is self-funding even at low oil prices. It also has strong insider ownership with management largely compensated in stock.

Opportune acquisition timing – Calima was able to acquire Blackspur as the company was struggling in 2020 under a heavy debt burden after COVID hit and oil prices crashed. The timing was opportune given the recovery in oil prices since the deal was negotiated last year, evidenced by Blackspur's Canadian E&P peer group share prices up +180% on average year to date. C$200mm of historical investment has gone into the asset base that was acquired for C$61.5mm. As well as Calima negotiating a good deal, it has changed its equity story into something that is more aligned with current investor appetite.

At our base case valuation of US$60/bbl Brent (US$57/bbl WTI) and US$3/mcf Henry Hub gas, we see a risked NPV10 of C$168mm for the Blackspur assets (2P only), which is ~175% higher than what Calima paid. Looking at it another way, we believe that the deal priced-in US$45/bbl Brent on a risked basis, versus the current price of almost US$70/bbl.

Risked and unrisked value (NPV10) of Blackspur assets ($Cmm) at various Brent oil prices (US$/bbl)



Source: H&P estimates

Investment case – Calima offers exposure to current oil prices and future higher North American gas prices. It has a strong balance sheet (0.5x ND/EBITDA), is a low-cost oil producer with the ability to offer a combination of strong free cashflow generation at oil prices north of US$50/bbl WTI and with the ability to use this to both return cash to shareholders and demonstrate strong, low risk growth through its existing proved reserves. In a continued higher oil price environment, there is the potential to grow faster, locking in the returns through hedging given fast payback of <6 months at >US$60/bbl WTI. In a low price environment, Calima benefits from a low breakeven (~US$26/bbl WTI) and low base decline rates given conventional production. Crucially its assets have access to major pipeline infrastructure. Its Montney assets give leverage into rising global gas demand and the growth in North American LNG exports.

Risked NAV AUD c/sh at different oil price and discount rates

		Brent Oil price (US$/bbl)				
		$40.00	$50.00	$60.00	$70.00	$80.00
Discount rate	6%	1.1c	2.3c	3.3c	4.4c	5.5c
	8%	0.8c	1.9c	2.8c	3.8c	4.7c
	10%	0.7c	1.6c	2.4c	3.3c	4.1c
	12%	0.5c	1.4c	2.1c	2.9c	3.6c
	14%	0.4c	1.2c	1.9c	2.5c	3.2c

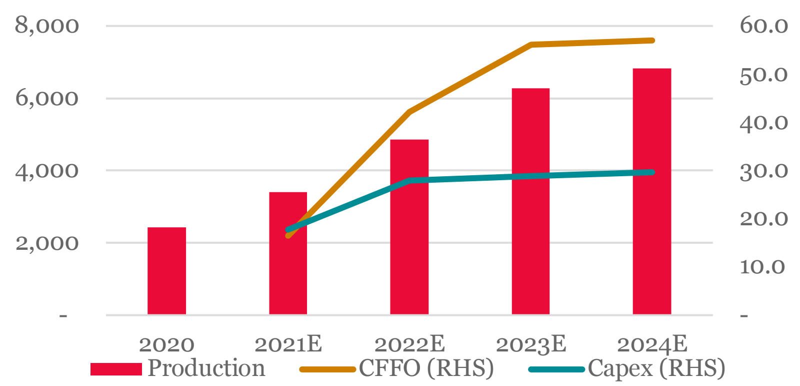
Source: H&P estimates

Valuation: 170% upside to our risked NAV – Our primary valuation methodology is a risked NAV of AUD 2.4c/sh at US$60/bbl Brent and a 10% discount rate. There is also 13% upside to our Core NAV of AUD 1.02c/sh, which only includes the 1P reserves. On a multiple basis, we estimate that Calima is trading on 2022 EV/CFFO of 2.4x. Using the ~C$25mm valuation for the Montney implied by the Calima share price pre-Blackspur, sees it trading on just 1.8x EV/CFFO in 2022, versus the Canadian peer group on 4.4x. On operational metrics, we see Calima trading on EV/2P reserves of C$4.6/boe versus the C$24/boe of post-tax cashflow we expect in 2022; and on a flowing barrel basis it is on $21k per boe/d in 2022. Cash distributions will be driven by market conditions and achieving sustainable production of >5kboe/d, which we expect in 2022.

Attractive cost of debt lowers cost of capital – Calima has a C$25mm RCF at an interest rate of just 4%, significantly lower than many E&P companies globally. This implies a lower cost of capital and a higher multiple and equity valuation for the company. In our base case we use a 10% discount rate as this is the norm for North American companies, however there is an argument for a lower rate. The table above shows the impact of lower discount rates. We estimate that Calima is trading on 2021 net debt to EBITDA of 0.6x or annualising H2'21 EBITDA it would be on <0.5x. Therefore, we see the potential for Calima to take out more debt over the next 12 months whilst remaining on very comfortable metrics. Its Canadian peer group is highly leveraged on 3.3x net debt to CFFO in 2021. Assuming 2x net debt to CFFO in 2022 implies Calima could manage C$90mm of net debt. Also, we note Calima's decommissioning liabilities are 18% of its EV versus the peer group at 82%.

Canada: investor friendly jurisdiction – Canada is an established energy market with a supportive energy policy. The fiscal regime in Canada is attractive too, with relatively low Government take, especially for a low risk established oil province. Canada has had carbon pricing for more than a decade, however, the lower carbon intensity of Calima's production relative for example to the oil sands puts it at a competitive advantage. Also, the combination of low carbon production and low carbon LNG export plants, should allow Canada to market some of the lowest carbon LNG globally. Regions like Western Canada with proven reserves and significant infrastructure in place should be key destinations for investors.

Blackspur asset's estimated production (boe/d) and cashflow/capex (C$mm)



Source: H&P estimates

Alberta conventional oil leveraged to prices – Blackspur produced 2.5kboe/d in Q1 and is expected to more than double production by 2022 to 5.5kboe/d with growth to >10kboe/d possible from the current 2P reserves (in total ~250 drilling locations). Brooks is a land position with a large resource in place, low cost structure, established infrastructure and year-round access. The tax loss position of Calima means no cash tax for the next few years. Thorsby is a large, consolidated land base containing a delineated resource play with large inventory that is development ready providing long-term development potential. The Thorsby area can provide stable and consistent production and cash flow or be a platform for meaningful growth. Current WCS pricing of >C$60/bbl is significantly above the full cycle break-even price of between C$30-40/bbl for its main inventory.

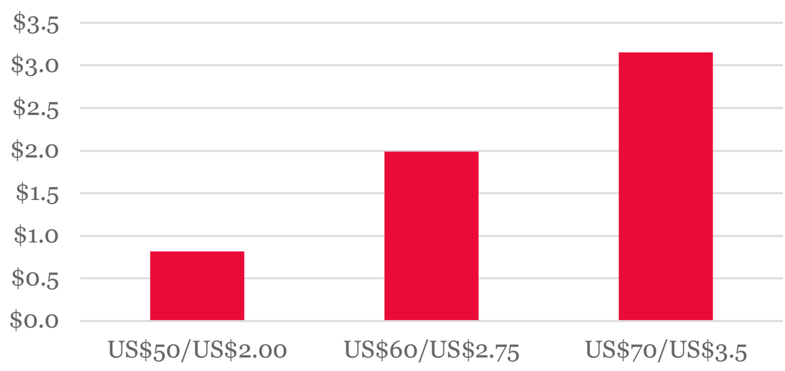
Stands out versus its Alberta peer group – Relative to its peer group (mid-cap Alberta oil weighted producers), Blackspur has stronger production and cashflow growth in 2022, without any acceleration of activity. It now has a much healthier balance sheet, both in terms of much lower net debt and decommissioning liabilities. It also has a higher reserve base than peers and a lower cost base leading to higher margins and more downside protection.

Potential to grow materially faster and move 2P to 1P – Our modelling is based on the base case drilling scenario for the 2P reserves, which assumed a more conservative macro environment. We think that higher prices could lead to an acceleration of drilling and the production forecasts are based off the conservative well type curves rather than the better results that have been realised by Blackspur. Therefore, there is the potential to grow significantly faster than planned, whilst continuing to generate free cash flow. Blackspur already has a large drilling inventory with greater than 60 booked PUD locations. However, it sees a further ~210 locations on its acreage.

Previous Canadian crude pricing risks much diminished – A key issue for Canadian producers (and in fact one that Blackspur faced) was large discounts in the market for Canadian crude. This was caused by a lack of pipeline capacity to evacuate the crude, which is no longer the case with added new capacity. We expect differentials to remain narrow, due to the fact that there have been no material projects sanctioned in the oil sands and the limited volume growth on offer ex-oil sands, meaning that there is sufficient pipeline capacity and future pipeline capacity additions may materially exceed supply growth. Also, Canadian crude was discounted given its heavier nature, but declines in global heavy crude production and an excess of light crude from US shale plays have led to a narrowing in the quality differential.

Australian listing: similar playbook to Oz CBM to LNG – Calima's decision to list in Australia was due to a desire to offer Australian investors a unique way to participate in the Canadian oil and gas market as well as the founders being based in Australia. Also, the Montney story should resonate with many Australian investors that are aware of the impact that the arrival of LNG can have on resource owners. In Queensland, once LNG trains were sanctioned at Gladstone, domestic resource owners and producers such as Queensland Gas, Pure Energy and Arrow Energy went through a sustained period of valuation increase and consolidation before being acquired by international companies such as Shell, BG and Petrochina.

Sensitivity of Montney NPV10 (C$/boe) to Brent (US$/bbl) and AECO (US$/mcf)



Source: H&P estimates

Montney optionality – Calima was incorporated as an explorer focused on the Montney and the company succeeded in what it set out to prove. Calima now has >1Tcfe of liquids rich natural gas resource in the Montney play. >50mmboe of 2C resource will be converted to 2P reserves once it secures funding to build the tie-in pipeline from its existing well pad into its owned infrastructure. Interest in the play has been picking up with a wave of recent corporate activity, moving it from a buyer's market to a seller's market. We see the Montney play as having attractive standalone economics; however, we think that it currently struggles to compete for limited capital versus the assets that have been acquired from Blackspur. We expect liquids to account for 50% of revenue but only 25% of production. In a higher gas price environment, the economics still improve markedly for the Montney. Calima is carrying >A$60mm of value on its balance sheet relating to these assets. We value the base case 50mmcf/d development scenario as worth ~C$250mm (C$2/boe) unrisked and heavily risked we carry C$56mm of value in our NAV.

Bullish North America gas pricing outlook – We believe that North American gas prices are biased higher for several reasons: global LNG and spot gas prices are influenced by higher oil prices (e.g. majority of LNG still priced off crude); North American associated gas production has been impacted by lower shale oil development, which remains restrained by E&P's new found capital discipline; and export demand is rising as new LNG projects are coming on line with further projects likely to take FID this year. We assume a conservative AECO gas price of US$2.75/mcf long term in our base case.

Management – Calima's management has always been highly incentivised by equity and aligned with shareholders, which has helped to keep G&A low. Calima's corporate overheads were <A$1mm in 2020 and most of the staff expense was taken as equity. Importantly, Calima has gained a strong management team with the Blackspur acquisition. The previous management team at Calima was more exploration-focused and with the transition to become a producing company there is now a more fit-for-purpose team in charge with members of the original management team remaining on the board. Blackspur was built bottom up by a team of oil and gas professionals who have established an impressive track record as oil finders, and efficient developers. It was a technically focused company with both founders geologists. The Blackspur management team has proven credentials in spotting overlooked high return oil plays, drilling some of the best performing wells in the plays in which it is present, and sharply reducing operating costs and G&A.

M&A opportunities – Blackspur management has plenty of experience of acquiring non-core assets from larger peers (e.g. deals with Cenovus and XTO, a subsidiary of Exxon). The team has worked at a variety of small and large companies gaining a wealth of information about the basin and who all the players are. The company has a strong track record of spotting deals based on this knowledge bank. They have completed around a dozen deals since taking over the company to expand and complement their asset base. In the current market there are likely to be opportunities to further expand its acreage position or even add a similar low cost, oily play in the Alberta area, although we think that it will be hard to match what it currently has in its inventory. At current oil prices, we think the bid/ask spread between buyers and sellers is more reasonable, evidenced by many deals taking place in recent months.

Corporate Social Responsibility plan –ESG is an increasingly important issue for investors in the oil and gas industry. Blackspur's investment in a regenerative, proprietary H_2S removal technology called H2Sweet allows the Brooks asset to lower its CO_2 emission rates and offers several positive economic and environmental benefits versus traditional technology. Blackspur's environmental ESG record will provide a pathway for best practise oil and gas development. It is also part of the Alberta TIER program, which means that it has targets for CO_2 reduction instead of having to pay carbon tax.

Investment risks – We see the main risks as: weaker oil prices and bottlenecks re-emerging for Canadian crude and gas exports; more onerous oil and gas fiscal regime coming into place in Canada over time; development wells underperform expectations, mitigated by conservative type curves; cost inflation but there is room to absorb this given the high margins at current oil prices. Calima currently does not have the means to finance a significant development of its Montney position but there is no near term need to do so, with very low costs to hold the assets. There is also the risk that some of the legacy Blackspur holders or legacy Calima shareholders look to exit the stock given higher liquidity, which may have a temporary negative impact on the share price. However, in the longer term we see higher liquidity as a positive, as it opens up the stock to a wider investor base.

Catalysts

There are various catalysts that we see potentially positively impacting the equity story over the coming year.

- **Brooks Sunburst well results generating >500% IRR** – Blackspur drilled three wells in March at a cost of <C$2.2mm (20% below budget), the initial production rates were >500boe/d combined (+14% vs. Blackspur's Q1'21 production). We estimate that the NPV10 of the wells is >C$9mm on our base case oil price assumptions and type curves (which currently look conservative), generating C$7.4mm of cash flow from operations by the end of 2022. The wells will pay back in less than 6 months and generate a >500% before tax IRR.

- **Well / type-curve outperformance** – We think that there is a good chance that the initial Sunburst wells mentioned above will outperform the reserve auditor's type curves based on the drilling results to date (28% type curve outperformance of initial production rates announced on 7th May). Also, on Thorsby, the reserve consultant's type curve for the proved locations is conservative as it is based on an earlier well completion design; the new higher intensity completion has significantly better productivity and economics. This could lead to reserves upgrades from higher reserves from existing booked wells plus further wells being included in the 1P reserves category.

- **Acceleration of drilling/production targets** – Calima has guided to providing an update on its drilling programme in late May. There are a further six wells in the programme for 2021 from late-May onwards. The company mentioned that there may be an opportunity to accelerate or exceed the projected target of a 3,000 boe/d average for 2021 (we forecast 3,400boe/d). There is ample inventory on the Alberta acreage, where high returns can be locked in by hedging at current pricing, giving less than 6 months payback on some locations. We would expect potentially another 3-5 wells. Calima can quickly respond to rising energy prices by accelerating its drilling programs given its ability to convert wells from spud to on-stream in 30-60 days.

- **Bolt-on acquisitions** – Given the large existing drilling inventory mentioned above, there is no need to replenish inventory. We expect Calima to look at small bolt on acquisitions in and around its existing Brooks/Thorsby acreage. We would expect these to be low cost and high value-add acquisitions due to cost and logistical synergies. There may also be the opportunity to add a further play in the Alberta region to establish a 3rd core area, leveraging off management's ability to spot low-cost development opportunities using innovative approaches.

- **Montney regional activity** – Calima's strategy is to prepare the Montney asset for future development while unlocking value short term via joint ventures, partnerships or a corporate transaction. Whilst we do not expect any operational activity this year, we believe that further M&A activity in the vicinity will be positive for Calima, as will the performance of the other listed Montney focused stocks (e.g. Arc Resources and Tourmaline) and drilling results from nearby acreage (e.g. private company Saguaro).

- **Canadian LNG project progress** – Canadian LNG export volume growth over the rest of this decade is a positive for Calima's Montney position as it would boost demand and gas prices. There are several LNG export plants planned that could take FID over the next 12 months. Also progress on the current LNG Canada plant that is under construction and a potential expansion project will be closely watched.

- **Canadian oil and gas pipeline news flow –** Access to both oil and gas pipeline infrastructure in Canada is critical to avoid large discounts for Canadian oil and gas in relation to US and global prices. The progress of pipeline upgrades and expansions, especially into the US will be important. However, given that post-COVID development plans have been scaled back and discounts have narrowed substantially, this appears less of a risk than in the past.

- **Share consolidation** – A share consolidation is likely given that the equity raise in relation to the Blackspur deal was done at a share price of AUD <1c/sh with the share count now at over 10bn shares outstanding.

- **Discover Exploration news flow** – Calima has a 5% stake in a private E&P company, Discover Exploration, which has exploration assets off East Africa and development assets in the Netherlands. If there is a liquidity event in Discover, we believe that Calima may look to exit its position which we value at just C$1mm.

- **H2Sweet progress** – Calima's H2Sweet joint venture is currently looking to deploy its proprietary technology on oil and gas projects globally. If it can win a few projects and prove the technology with 3rd parties, there is a large value creation opportunity. However, for now we value the investment in line with book value (C$0.4mm).

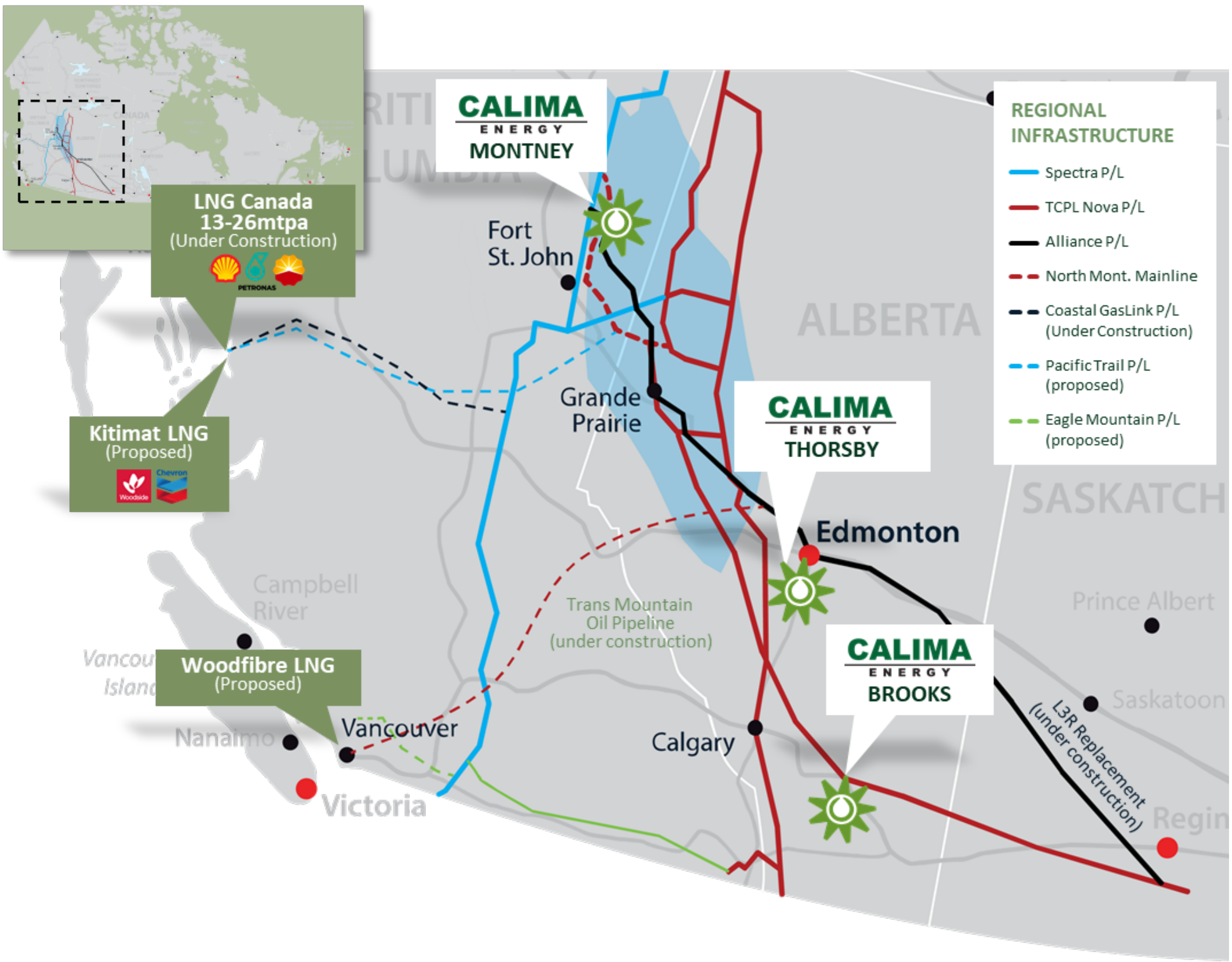
- **Debt refinancing** – With the potential growth from the Blackspur assets, we believe that Calima will be able to take on more debt at attractive levels without straining the balance sheet. On our base case we see Calima's net debt to cashflow at just 0.5x (based on YE'21 net debt and H2'21 annualised CFFO). We think that further debt will allow Calima to accelerate production whilst also looking at shareholder distributions in 2022. Calima's peer group of Alberta oil producers are trading on an average of 3.3x net debt to 2021E CFFO.

- **Hedging** – Given the returns available and <1 year payback on wells, we would not be surprised to see Calima layer on further hedging for this year and 2022. Given both the absolute oil price (WTI) is high (above our long term forecast of US$57/bbl) and the spread to WCS is narrow, we think that both could be locked in.

- **Nisku and Duvernay derisking** – Blackspur has significant potential on some higher cost drilling targets on its Thorsby acreage. These are currently lower priority given that it has ample inventory in the already derisked Sparky play. However, the scoping economics on the Nisku play look strong at current prices and the Duvernay has seen positive offset results by other companies nearby. We think that there may be organic development opportunities for the Nisku and the potential to sell the rights to the Duvernay to a company focused on this reservoir interval.

Company Overview

Map of Calima's key assets and regional infrastructure



Source: Calima

Calima (ticker "ASX:CE1") is an Australian listed E&P company with its core assets in Canada. It was formed in 2017 by a team of leading global explorationists to test a play concept on the fringe of the Montney, which is a leading resource play in North America. It has a large position of ~60k acres, where it has successfully derisked almost 200mmboe of contingent resource in an area that most thought would not be prospective. Its recent acquisition of private Canadian company Blackspur has added low-cost, oil-weighted production, significant cash flow generation and plenty of high return growth potential.

Blackspur was formed in 2012 and followed through with acquisitions of C$74mm and drilled 59 oil wells funded via a combination of equity and debt. In Q3'18 Blackspur reached peak production of over 5,000 boe/d. Blackspur has two core production areas in Southern Alberta; Thorsby and Brooks. The Brooks asset produced in Q4 2020 ~1,860 boe/d and Thorsby ~740 boe/d. The combined assets have a liquids ratio of 70% and has a peer leading Liability Management Ratio (LMR) rating of ~4.6 with undiscounted Asset Retirement Obligation (ARO) estimated at ~C$14.2m.

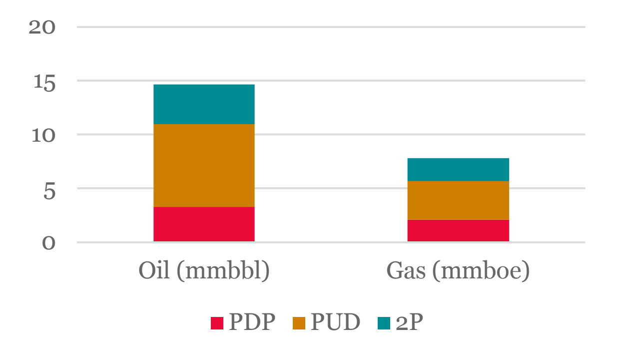
Merger with Blackspur

Calima's merger with Blackspur, which was completed on 3rd May, creates a mid-tier, ASX-listed company, with strong cash flow from high return conventional oil assets that have been undercapitalised for several years, combined with growth potential from Calima's legacy significant undeveloped resource portfolio in the Montney. This provides a combination of portfolio depth, strong production growth and Blackspur's skill at efficiently developing oil plays. Blackspur is a low-cost producer that is not expected to pay cash tax for a few years. This creates downside protection (<US$30/bbl WTI break-even), whilst providing exposure to higher oil and gas prices. Calima has struck the deal at a significant discount to replacement cost, given the price equates to 30% of the amount spent by Blackspur to date in acquiring leases, drilling wells and developing infrastructure.

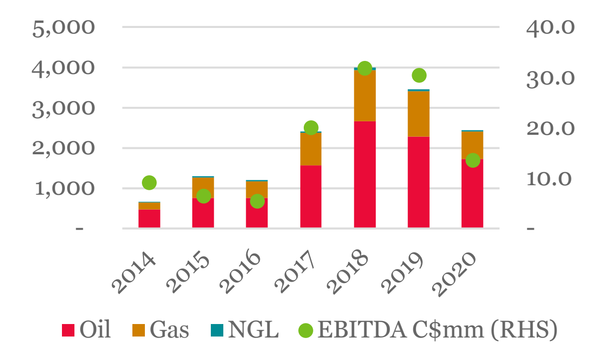
Company Overview

Blackspur was formed in 2012 and grew through acquisitions totalling C$74mm. It has drilled 59 oil wells funded via a combination of equity and debt. Blackspur has two core production areas in Southern Alberta: Thorsby and Brooks. Q4 2020 production averaged of 2,600boe/d (70% oil) of which Brooks was 1,860boe/d and Thorsby 740boe/d. There is 10,000boe/d of processing capacity with a near-term goal to raise production to 5,500boe/d. The assets have 2P reserves of 22.5mmboe. 1P reserves of 16.7mmboe of which PDP reserves are 5.4mmboe.

Blackspur reserves (mmboe)



Blackspur production (boe/d) and EBITDA



Source: Company data

Blackspur was built from the ground up by a team of oil and gas professionals who have established an impressive track record as oil finders, and efficient developers. The team has carefully assembled and de-risked Blackspur's assets through a combination of drilling and acquisition over the past decade and are focuesd on synergistic growth opportunities across the Western Canadian Sedimentary Basin.

Acquisition detail

Calima announced the acquisition on 25th February 2020. The enterprise value of the deal is C$61.5mm (inclusive of C$41mm in net debt) and includes all assets, reserves, production and the management team of Blackspur. There is also an undiscounted asset retirement obligation estimated at ~C$16.9 million. The equity value component of the deal is C$21.5mm. This was paid for with C$16.6mm of Calima equity (issued at AUD 0.7c/sh) with the balance of C$4.9mm paid in cash. Calima has raised A$38mm in new equity through a placement of A$31mm and A$7mm Retail Offer to fund the cash component of the deal, deal costs and repay C$25mm of debt. The placing price was a 30% discount the previous closing price of AUD 1c/sh. The existing Calima shareholders now own 23% of the expanded share count, Blackspur holders 24% and new equity investors 53%.

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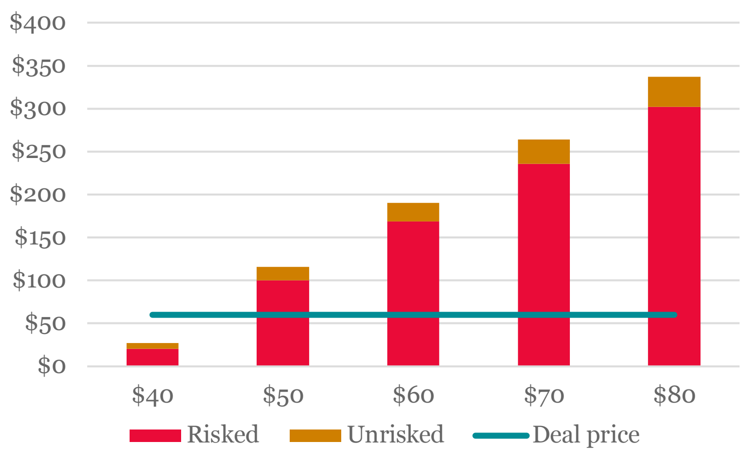
2P valuation (C$mm) versus deal price at various Brent prices (US$/bbl)



Source: H&P estimates

Acquisition metrics

We have put together a table of the key financial and operational metrics for Blackspur's mid to small cap peer group with a similar asset base in Alberta and which are listed in Canada. The companies have an average market capitalisation of over C$100mm and around 2/3 of their production is oil. Production averaged just over 10kboe/d in 2020 and on average they have 44mmboe of 1P reserves. We have also included Calima based on its current valuation with C$25mm of value stripped out as a conservative value for its Montney assets based on where it was trading prior to the deal.

Key financial metrics (C$mm)

Company	Market Cap	Net debt	EV	ARO	ARO as % of EV	ND/ CFFO	EV/CFFO '21	EV/CFFO '22
Bonterra Energy	145	316	461	157	108%	3.6	5.3	4.9
Cardinal Energy	446	247	693	331	48%	2.4	6.6	5.1
Gear Energy	181	53	233	88	37%	1.1	4.8	4.2
InPlay Oil	43	74	117	80	69%	2.0	3.2	2.8
Journey Energy	41	90	131	192	146%	2.6	3.8	4.6
Obsidian Energy	151	468	619	597	96%	3.1	4.1	4.2
Prairie Provident	8	116	124	221	179%	9.1	9.7	0.0
Surge Energy	208	381	589	280	48%	4.5	6.9	4.9
Hemisphere Energy	48	25	72	8	11%	1.3	3.8	0.0
Peer group average	**141**	**197**	**338**	**217**	**82%**	**3.3**	**5.4**	**4.4**
Blackspur	**21**	**41**	**62**	**17**	**27%**	**1.6**	**2.5**	**1.5**
BS vs. Comps					-67%	-50%	-54%	-67%
Calima (ex-Montney)	**63**	**12**	**75**	**17**	**23%**	**0.5**	**3.0**	**1.8**
Calima vs. Comps					-73%	-86%	-45%	-60%

Source: H&P estimates, Capital IQ

The table above shows that Blackspur (based on acquisition price) has significantly lower undiscounted asset retirement obligations (ARO) than the peer group: only 27% of its EV versus 82% for the peers. Also, at the time of the deal, its balance sheet was more comfortable than peers at 1.6x net debt to 2021 CFFO versus the peer group which is at 3.3x. After the deal, the equity raised by Calima to pay off debt has taken this to 0.5x. On a cashflow multiple basis the deal was done at a 54% discount to peer average 2021 EV/CFFO and even greater 67% discount to 2022.

Key operational metrics (C$mm)

Company	EV per kboe/d (C$)	EV/PUD (C$/boe)	EV/1P (C$/boe)	EV/2P (C$/boe)	1P R/L (years)	2P R/L (years)	G&A (C$/boe)	Opex (C$/boe)
Bonterra Energy	35.5	13.9	6.1	4.9	19.5	24.3	2.5	15.1
Cardinal Energy	39.0	10.8	9.2	7.0	11.2	14.7	2.0	17.7
Gear Energy	42.8	32.4	18.0	9.9	6.7	12.2	2.7	17.0
InPlay Oil	22.2	12.1	5.4	3.6	14.9	22.6	3.1	15.3
Journey Energy	17.6	6.5	4.5	2.6	9.5	16.3	2.0	13.0
Obsidian Energy	26.3	10.2	6.5	4.8	10.2	13.8	1.5	13.1
Prairie Provident	28.1	15.2	6.8	4.4	10.5	16.0	3.6	21.3
Surge Energy	35.4	22.9	10.3	7.2	8.7	12.5	1.9	16.2
Hemisphere Energy	38.0	16.9	6.2	4.8	18.9	24.2	3.1	9.3
Peer group average	**31.7**	**15.6**	**8.1**	**5.5**	**12.2**	**17.4**	**2.5**	**15.3**
Blackspur	**18.1**	**11.4**	**3.7**	**2.7**	**18.8**	**25.3**	**2.5**	**9.3**
BSO vs. Comps	-43%	-27%	-55%	-50%	53%	45%	1%	-39%

Source: H&P estimates, Capital IQ

The table above shows how Blackspur compares to its peers in relation to its production and reserves. Looking at it on a price per flowing barrel of production, the acquisition price was at a 43% discount to the peer group average. On reserves it is on a 27% discount on PUD and 50-55% discount on 1P and 2P reserves. It actually has around a 50% higher reserve life of 19-25 years on 1P and 2P reserves. On operating costs it is 39% lower than peers and has the lowest costs in the group and is competitive on G&A/boe especially given its smaller size.

We see several factors that mean that Blackspur should actually be valued at a premium to the peer group:

1. It has a much healthier balance sheet than peers.
2. It has significantly lower decommissioning liabilities than peers.
3. It has stronger production and cash flow growth expected in 2022 (without any acceleration factored in).
4. It has a much higher reserve life than peers (i.e. it can grow through its existing inventory).
5. It has a much lower cost base than the peer group, meaning higher margins and more downside protection.

Assuming Blackspur traded in line with the peer group on 4.4x 2022 EV/CFFO, would imply a valuation of C$186mm and if it traded at the top of the peer group it would imply a valuation of C$213mm. Including C$25mm in value for Calima's legacy Montney assets and taking off the debt this would imply an equity value of C$225mm vs the current market cap of C$92mm.

Valuation

Our favoured valuation methodology is a bottom-up risked NAV, in which we have built a DCF valuation of the 2P reserves, plus the main development and exploration prospects (assuming they will be developed), and then risked them for geological and commercialisation risk. We also take a look at how Calima compares on a multiple basis.

Table of key assumptions

Main assumptions	US$	C$	Main assumptions	US$	C$
2021+ Brent Oil price	$60	$75	NGL 2021+	$29	$36
2021+ Brent - WTI spread	$3	$4	NGL 2022	$29	$36
2021+ WTI-WCS spread	$12	$15	2021+ Henry Hub gas price	$3.0	$3.8
Brooks premium to WCS	$2	$3	2022+ HH minus AECO	$0.25	$0.3
Thorsby premium to WCS	-$4	-$5	Discount rate	10%	

Source: H&P estimates

In our base case scenario, we use US$57/bbl WTI long-term flat from 2021, a US$12/bbl differential to WCS pricing, US$2.5/MMBtu AECO gas price in 2021 and US$2.75/MMBtu AECO gas price in 2022+, a US$1.25/AUD exchange rate, US$1.25/CAD exchange rate and a 10% discount rate from 1/1/2021. Our risked NAV is AUD 2.42c/sh, which implies 169% upside from the current share price. Calima currently trades on a 12% discount to our Core NAV of AUD 1.02c/sh. On an unrisked basis we have a NAV of AUD 6c/sh or >6x upside.

NAV

Asset	Gross mmboe	Interest	Net mmboe	NPV C$/boe	Unrisked C$m	Unrisked A$c/sh	Geological CoS	:ommercial CoS	Risked C$m	Risked A$c/sh
Net debt (end-Apr '21)					-$12	-0.11			-$12	-0.11
Asset retirement obligations					-$13.6	-0.13			-$13.6	-0.13
Options proceeds					$2.2	0.02			$2.2	0.02
Hedging gain/loss					-$2.5	-0.02			-$2.5	-0.02
Brooks PDP reserves	2.7	100%	2.7	$11.9	$32.4	0.31	100%	100%	$32.4	0.31
Thorsby PDP reserves	2.0	100%	2.0	$9.0	$18.4	0.18	100%	100%	$18.4	0.18
Brooks planned PUD	5.7	100%	5.7	$14.4	$82.4	0.79	100%	90%	$74.2	0.71
Thorsby planned PUD	5.6	100%	5.6	$6.7	$37.0	0.35	100%	90%	$33.3	0.32
H2 Sweet					$0.4	0.00			$0.4	0.00
Workovers/other capex					-$17.2	-0.16			-$17.2	-0.16
Capitalised G&A @ 2x		-4.4			-$8.9	-0.08			-$8.9	-0.08
1P Core NAV	**16.0**		**16.0**	**$7**	**$119**	**1.13**			**$107**	**1.02**
Incremental Brooks 2P	2.5	100%	2.5	$9.5	$24.2	0.23	90%	90%	$19.6	0.19
Incremental Thorsby 2P	3.4	100%	3.4	$7.8	$26.3	0.25	90%	90%	$21.3	0.20
Brooks remaining unbooked	12.9	100%	12.9	$7.1	$91.9	0.88	50%	50%	$23.0	0.22
Thorsby remaining unbooked	6.6	100%	6.6	$5.9	$38.4	0.37	50%	50%	$9.6	0.09
Montney 2C 50mmcf/d	125	100%	125	$2.0	$248	2.37	90%	25%	$55.8	0.53
Montney remaining 2C	68	100%	68	$1.0	$67.8	0.65	75%	20%	$10.2	0.10
Development upside	**192.4**		**192.4**		**$316**	**3.02**			**$139**	**1.33**
Montney Prospective Resource	364	100%	364	$0.5	$182.1	1.74	33%	10%	$6.0	0.06
PEL-10 production licence					$6.3	0.06	25%	25%	$0.4	0.00
PEL-10 commercial production					$6.3	0.06	25%	10%	$0.2	0.00
SADR exploration		50%							$0.0	0.00
5% in Discover Exploration Ltd									$1.0	0.01
Exploration upside	**364.1**		**364.1**		**$195**	**1.86**			**$8**	**0.07**
Total NAV					**$629**	**6.01**			**$254**	**2.42**

Source: H&P estimates

Core NAV

Net debt – In our NAV we use the estimated net debt for Calima on closing of the Blackspur acquisition at the end of April of A$12mm.

Asset retirement obligations – We include the balance sheet value of the asset retirement obligations, which is C$14mm. This is mainly associated with the well abandonment obligations from the Blackspur assets and is likely to be spread over a period of more than a decade. Blackspur expect to spend <C$1mm p.a. on ARO and the cost in 2020 and 2021 is being covered by a Government subsidy programme.

Options proceeds – Given that we use a fully diluted share count, we include the potential options exercise proceeds of A$2.2mm.

Hedging impact – We include the hedging impact from May 2021. The hedges in place for the remainder of 2021 are 140kbbl at a WCS price of ~C$39/bbl (versus our assumption of C$56/bbl), which has a negative impact of C$2.4mm. There is also ~300mmcf of gas hedged at an AECO price of C$2.83/mcf (versus our assumption of C$3.75/mcf), which has a negative impact of C$0.3mm.

PDP reserves – We have valued the 5.1mmboe of proved developed reserves (1P PDP) on Brooks and Thorsby separately and use a 100% geological and commercial chance of success given that this is simply the blowdown of the existing producing wells. Our combined risked valuation is C$51mm or AUD 0.49c/sh. This accounts for 83% of the acquisition price.

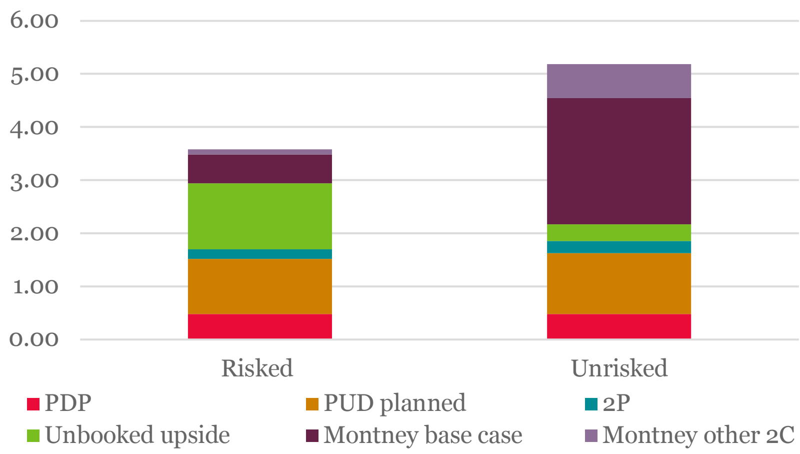
PUD reserves base case development – We have also included the 11.3mmboe proved undeveloped reserves. To be conservative, we risk these at a combined 90% chance of geological and commercial risk to factor in some risk of unproductive wells or development delays. However, given that these are proved reserves the risk level is very low. Our combined risked valuation is C$108mm or AUD 1.03c/sh.

H2Sweet – We include the book value of Blackspur's investment into H2Sweet, which is only C$0.4mm.

Workovers and other capex – We include the discounted cashflow for workovers on existing wells, maintenance/small upgrades to facilities etc. This is C$17mm or AUD0.16c/sh.

G&A – We expect FY 2022 cash G&A of C$4.4mm (C$2.5/boe), which we capitalise at 2x and leads to a negative value of AUD 0.08c/sh. We see downside to this G&A amount as although we assume G&A rises with production, we believe that Calima should be able to keep G&A roughly flat at ~C$3mm per annum.

Calima risked and unrisked NAV for proved, probable and contingent resource (AUD c/sh)



Source: H&P estimates

Development and exploration upside

2P reserves – Blackspur has a further 5.8mmboe of 2P reserves, which are likely to transition to 1P reserves over time with more drilling. We also use a higher combined geological and commercial chance of success of 81%. Our risked valuation is C$41mm or AUD 0.4c/sh.

Blackspur unbooked locations – Blackspur has a large inventory of around 150 unbooked drilling locations that could be progressed into 2P reserves over time. We conservatively estimate that there are 20mmboe of incremental resources and value these at a 75% haircut to the existing 2P reserve valuation given a time value of money impact. We use a conservative combined geological and commercialisation chance of success of just 25%. Our risked valuation is C$33mm or AUD 0.31c/sh. Unrisked we see this as worth AUD 1.25c/sh

Montney 2C initial development – Calima has 54mmboe of 2C resources that can be booked as 2P reserves once FID is taken on their development and the pipeline connection to Tommy Lakes is sanctioned. We include 125mmboe, which is what could be developed using the existing facility capacity of 50mmcf/d. We also use a lower combined geological and commercial chance of success of 22.5% as the funding for the development is not yet clarified and there is the potential for dilution. Our risked valuation is C$56mm or AUD 0.53c/sh.

Montney 2C on hold – Calima has a further 68mmboe of 2C resources that have been derisked by the recent exploration campaign but will require further infrastructure beyond the Tommy Lakes facility and sustained high pricing. We therefore use a low combined geological and commercial chance of success of <20%. Our risked valuation is C$10mm or AUD 0.1c/sh but our unrisked value is C$68mm or AUD 0.65c/sh.

SADR exploration acreage – We do not include any value for Calima's assets in SADR given that it is unlikely there will be any activity in the near-term due to the political dispute over the acreage ownership rights. A significant part of SADR is occupied by Morocco, which means Calima cannot undertake exploration.

Discover Exploration stake – Calima has a 5% stake in a private E&P company, Discover Exploration, which has exploration assets off East Africa and development assets in the Netherlands, which we value at just C$1mm.

NAV sensitivities

We look at the risked NAV for Calima at various oil prices and discount rates relative to our base case.

Risked NAV (AUD c/sh) at different oil prices and discount rates

		Brent Oil price (US$/bbl)				
		$40.00	$50.00	$60.00	$70.00	$80.00
	6%	1.1c	2.3c	3.3c	4.4c	5.5c
Discount	8%	0.8c	1.9c	2.8c	3.8c	4.7c
rate	10%	0.7c	1.6c	**2.4c**	3.3c	4.1c
	12%	0.5c	1.4c	2.1c	2.9c	3.6c
	14%	0.4c	1.2c	1.9c	2.5c	3.2c

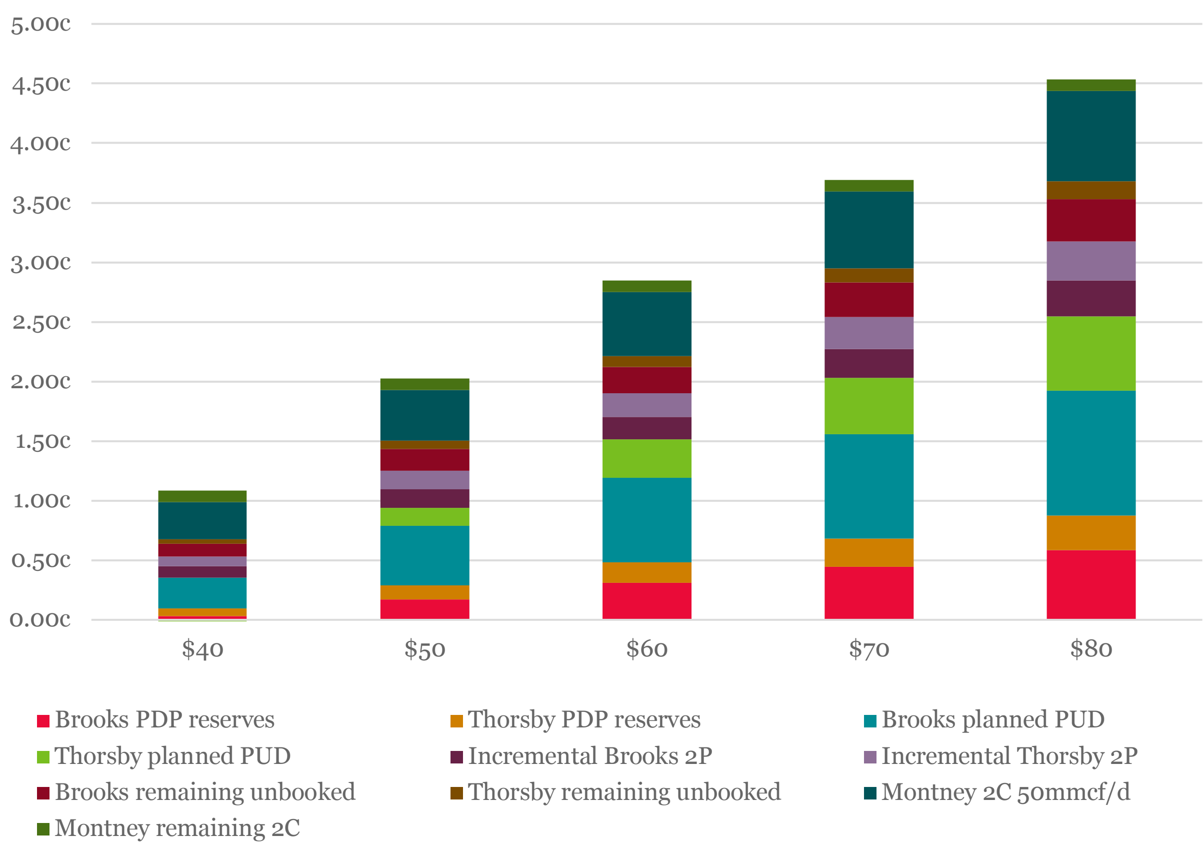
Source: H&P estimates

Risked NAV (AUD c/sh) at different gas prices and discount rates

		Henry Hub (US$/mcf)				
		$2.00	$2.50	$3.00	$3.50	$4.00
	6%	2.6c	3.0c	3.3c	3.7c	4.0c
Discount	8%	2.2c	2.5c	2.8c	3.1c	3.4c
rate	10%	1.9c	2.2c	**2.4c**	2.7c	2.9c
	12%	1.7c	1.9c	2.1c	2.3c	2.5c
	14%	1.5c	1.7c	1.9c	2.0c	2.2c

Source: H&P estimates

Risked NAV (AUD c/sh) key asset breakdown at different Brent oil prices (US$/bbl)



Source: Company Data; H&P estimates

Valuation metrics and multiples

The table below shows the key financial ratio and operational metrics for Calima. We have shown a detailed analysis of the Blackspur metrics relative to its peers on page 12. If we assume that Calima trades in line with peers on 2022 EV/CFFO of 4.4x, this implies an EV of C$185mm adding on C$50mm of value for the Montney (see page 46) gives a total value of C$235mm versus its current EV of ~C$100mm or 135% upside on an EV basis.

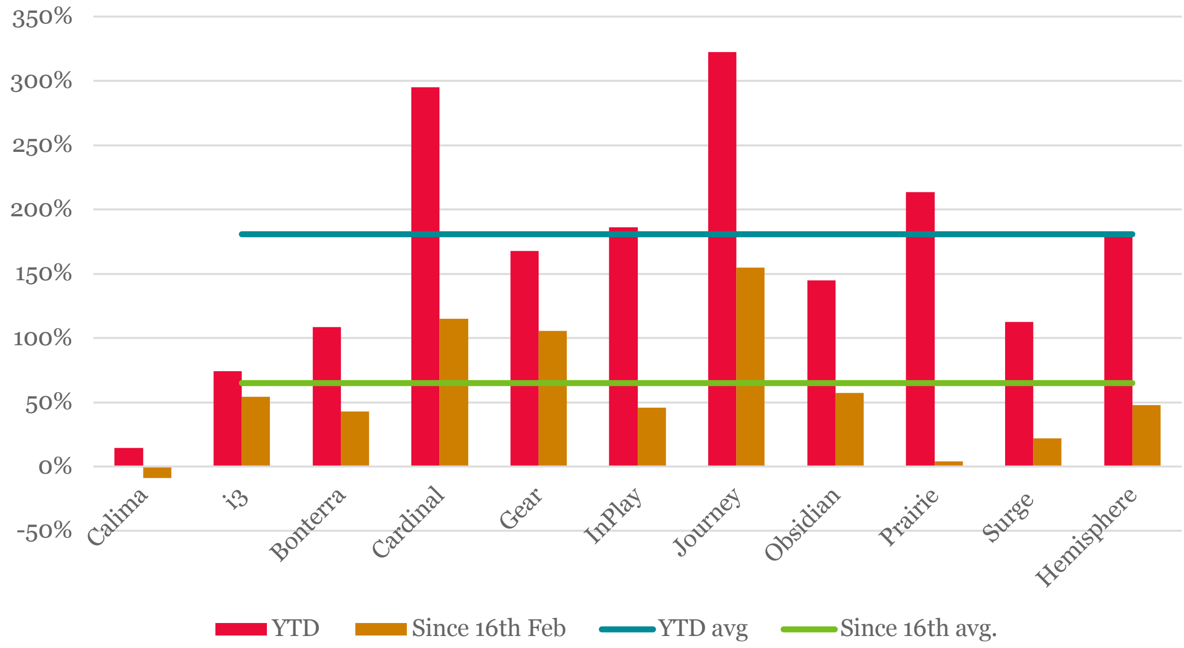
Financial ratios and multiples (C$mm)	2021E	2022E	2023E	2024E	2025E
Market capitalisation	92.4	92.4	92.4	92.4	92.4
Net debt	11.0	-$3.3	-$30.6	-$57.9	-$83.3
EV	**103.4**	**103.4**	**103.4**	**103.4**	**103.4**
Equity	169.6	188.0	219.1	253.7	284.4
Capital employed	180.5	184.7	188.5	195.9	201.1
EV/2P reserves (2020)	$4.6	$4.6	$4.6	$4.6	$4.6
EV per boe per day ($ per kboe/d)	$30.4	$21.3	$16.5	$15.2	$16.5
Cashflow per barrel ($/boe)	$19.9	$23.8	$24.5	$22.9	$21.2
EBITDA per barrel ($/boe)	$23.4	$24.0	$24.3	$23.6	$22.6
Net income per barrel ($/boe)	-$7.2	$10.4	$13.6	$13.9	$13.4
P/E	-15.5x	5.0x	3.0x	2.7x	3.0x
P/CFPS	5.6x	2.2x	1.6x	1.6x	1.9x
EV/EBITDA	5.3x	2.4x	1.9x	1.8x	2.0x
EV/CFFO	6.3x	2.4x	1.8x	1.8x	2.1x
ROAE	-3.5%	9.8%	14.2%	13.7%	10.8%
ROACE	-3.3%	10.0%	16.5%	17.7%	15.2%
FCF yield	-1.4%	15.5%	29.4%	29.6%	27.5%
Dividend yield	0.0%	0.0%	0.0%	0.0%	0.0%
Net debt/EBITDA	0.6x	-0.1x	-0.5x	-1.0x	-1.6x
Net debt/equity	6.5%	-1.8%	-13.9%	-22.8%	-29.3%
Net debt/capital employed	6.1%	-1.8%	-16.2%	-29.6%	-41.4%

Source: H&P estimates, CapIQ

We do not think it is that relevant to compare Calima to its Australian listed peer group, especially on reserves or production-based metrics as the reserves are not comparable given different fiscal terms and realisations.

Share price performance of peers

Calima peer group TSR year to date and since deal announcement (US$ terms)



Source: H&P estimates, Capital IQ

Calima's Canadian peer group has performed extremely strongly this year on the back of higher commodity prices and improved sentiment. Year to date the peer group has shown a total shareholder return of ~180%, which is in comparison to Calima that is up just 14% year to date. Since the acquisition was announced the peer group is up 65%, given the further recovery in the commodity price environment and improved Canadian sentiment. However, Calima is trading 9% lower than where it was before its shares were suspended on 16th February. The fact that the deal with Blackspur was negotiated in 2020 implies significant upside to the market value of Blackspur from the move up in the commodity and equity markets.

Financial Summary

Assumptions	2021E	2022E	2023E	2024E	2025E
USD:AUD FX rate	$1.25	$1.25	$1.25	$1.25	$1.25
CAD:AUD FX rate	$1.00	$1.00	$1.00	$1.00	$1.00
Brent (US$/bbl)	$60.00	$60.00	$60.00	$60.00	$60.00
WTI (US$/bbl)	$57.00	$57.00	$57.00	$57.00	$57.00
WCS (C$/bbl)	$56.25	$56.25	$56.25	$56.25	$56.25
Henry Hub (US$/mcf)	$3.00	$3.00	$3.00	$3.00	$3.00
AECO (US$/mcf)	$3.13	$3.44	$3.44	$3.44	$3.44
Brooks oil price (C$/bbl)	$58.75	$58.75	$58.75	$58.75	$58.75
Thorsby oil price (C$/bbl)	$51.25	$51.25	$51.25	$51.25	$51.25
NGL price (C$/bbl)	$35.63	$35.63	$35.63	$35.63	$35.63
Gas price (C$/mcf)	$3.13	$3.44	$3.44	$3.44	$3.44
Oil production (bbl/d)	2,328	3,153	4,081	4,318	3,957
Gas production (mcf/d)	6,134	9,751	12,603	14,327	13,280
NGL production (kbbl/d)	51	79	94	111	105
Total production (kboe/d)	3,402	4,857	6,275	6,817	6,276

Income Statement (C$mm)	2021E	2022E	2023E	2024E	2025E
Revenue	$37.3	$77.4	$100.4	$107.6	$97.7
Royalties	-$6.7	-$13.9	-$18.1	-$19.4	-$17.6
Opex and transportation	-$8.1	-$16.5	-$20.9	-$23.3	-$22.5
G&A	-$3.1	-$4.4	-$5.7	-$6.2	-$5.7
EBITDA	**$19.4**	**$42.5**	**$55.7**	**$58.7**	**$51.9**
DD&A	-$22.4	-$23.8	-$25.0	-$22.3	-$17.9
EBIT	**-$3.0**	**$18.7**	**$30.7**	**$36.4**	**$33.9**
Cash Interest	-$0.4	-$0.3	$0.4	$1.5	$2.6
Hedging (gains) losses	-$2.5	$0.0	$0.0	$0.0	$0.0
EBT	-$6.0	$18.4	$31.1	$37.9	$36.5
Tax	$0.0	$0.0	$0.0	-$3.2	-$5.9
Net income	**-$6.0**	**$18.4**	**$31.1**	**$34.7**	**$30.6**

Source: H&P estimates

Cash flow (C$mm)	2021E	2022E	2023E	2024E	2025E
Earnings before interest and tax	-$3.0	$18.7	$30.7	$36.4	$33.9
Depreciation	$22.4	$23.8	$25.0	$22.3	$17.9
Share based remuneration	$0.0	$0.0	$0.0	$0.0	$0.0
Cash interest charge	-$0.4	-$0.3	$0.4	$1.5	$2.6
Cash tax	$0.0	$0.0	$0.0	-$3.2	-$5.9
Other	-$2.5	$0.0	$0.0	$0.0	$0.0
Cash flow from operations (pre w/c)	**$16.5**	**$42.2**	**$56.1**	**$57.0**	**$48.6**
Decrease/(increase) in trade receivables	$0.0	$0.0	$0.0	$0.0	$0.0
Increase/(decrease) in trade creditors	$0.0	$0.0	$0.0	$0.0	$0.0
Decrease/(increase) in inventory	$0.0	$0.0	$0.0	$0.0	$0.0
Cash flow from operations (post w/c)	**$16.5**	**$42.2**	**$56.1**	**$57.0**	**$48.6**
Capital expenditure	-$17.7	-$27.9	-$28.9	-$29.7	-$23.1
Free cashflow	**-$1.3**	**$14.3**	**$27.2**	**$27.3**	**$25.4**
Acquisitions	$0.0	$0.0	$0.0	$0.0	$0.0
Disposals	$0.0	$0.0	$0.0	$0.0	$0.0
Dividends	$0.0	$0.0	$0.0	$0.0	$0.0
Change in net debt	**-$1.3**	**$14.3**	**$27.2**	**$27.3**	**$25.4**

Source: H&P estimate

Balance Sheet (C$mm)	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**
Cash and cash equivalents	$0.3	$14.6	$41.8	$69.2	$94.6
Trade and other receivables	$3.9	$3.9	$3.9	$3.9	$3.9
Prepaid expenditures and deposits	$0.1	$0.1	$0.1	$0.1	$0.1
Risk management assets	$0.8	$0.8	$0.8	$0.8	$0.8
Total current assets	$5.1	$19.4	$46.6	$74.0	$99.4
Other assets	$0.6	$0.6	$0.6	$0.6	$0.6
Property, plant and equipment	$134.1	$138.3	$142.1	$149.4	$154.7
Right of use asset	$0.7	$0.7	$0.7	$0.7	$0.7
Exploration and evaluation expenditure	$62.9	$62.9	$62.9	$62.9	$62.9
Investments	$0.4	$0.4	$0.4	$0.4	$0.4
Total non-current assets	$198.7	$202.8	$206.7	$214.0	$219.2
TOTAL ASSETS	**$203.8**	**$222.2**	**$253.3**	**$288.0**	**$318.6**
Bank indebtedness	$11.3	$11.3	$11.3	$11.3	$11.3
Trade and other payables	$2.9	$2.9	$2.9	$2.9	$2.9
Other Liabilities	$0.0	$0.0	$0.0	$0.0	$0.0
Total current liabilities	$14.2	$14.2	$14.2	$14.2	$14.2
Decommissioning obligation	$9.7	$9.7	$9.7	$9.7	$9.7
Deferred income tax liability	$1.7	$1.7	$1.7	$1.7	$1.7
Restoration provision	$4.8	$4.8	$4.8	$4.8	$4.8
Lease liabilities	$0.7	$0.7	$0.7	$0.7	$0.7
Loan	$0.0	$0.0	$0.0	$0.0	$0.0
Total Non-Current Liabilities	$17.0	$17.0	$17.0	$17.0	$17.0
TOTAL LIABILITIES	**$31.2**	**$31.2**	**$31.2**	**$31.2**	**$31.2**
NET ASSETS	**$172.6**	**$191.0**	**$222.1**	**$256.7**	**$287.4**
Issued capital	$346.7	$346.7	$346.7	$346.7	$346.7
Options/Mgmt Rights	$0.1	$0.1	$0.1	$0.1	$0.1
Fundraising Costs	-$3.1	-$3.1	-$3.1	-$3.1	-$3.1
Contributed surplus	$0.0	$0.0	$0.0	$0.0	$0.0
Reserves	$18.3	$18.3	$18.3	$18.3	$18.3
Accumulated losses	-$192.5	-$174.1	-$143.0	-$108.4	-$77.7
TOTAL EQUITY	**$169.6**	**$188.0**	**$219.1**	**$253.7**	**$284.4**

Source: H&P estimates

Balance Sheet and Funding

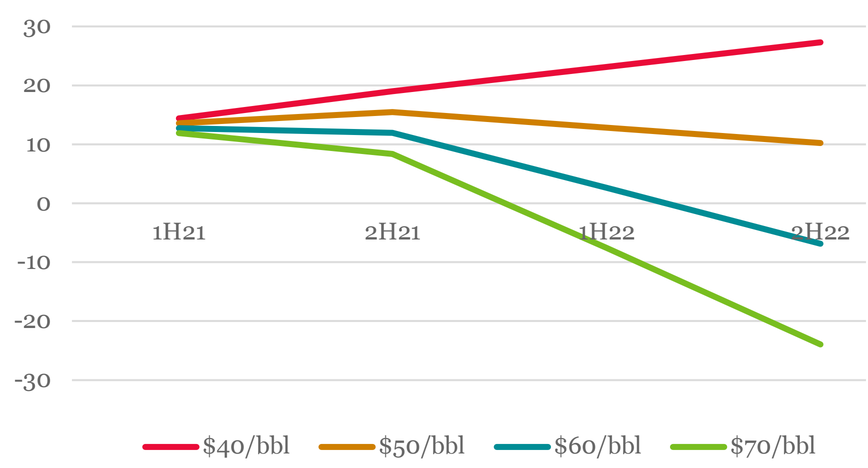
Calima had a small net cash position prior to the Blackspur deal. Calima repaid Blackspur's existing Non-Revolving and Revolving Credit Facilities (RCF) of C$50mm of which C$45mm was drawn (end-Q3'20) and established a committed RCF with National Bank of Canada of C$25mm.

Calima had C$12mm of net debt on closing of the Blackspur deal at the end of April. Calima will have C$13mm of headroom with its revolving credit facility of C$25mm, which functions like an overdraft facility, allowing Calima to keep cash on the balance sheet to a minimum. The cost of borrowing is <4%.

The only financial covenant is that the adjusted working capital ratio must be greater than 1x (i.e. the available credit facility plus receivables must be able to cover payables or other negative working capital items).

Terms	Committed Revolving Credit Facility
Facility Size	C$25m (<$13 million drawn)
Provider	National Bank of Canada
Interest Rate	CBR < 400bp
Tenor	No expiry, semi-annual review
Security	$150m demand debenture
Financial Covenants	Net Debt to Cash Flow Working Capital Ratio > 1.0x
Negative Covenants	Strict prohibition on any non-permitted senior, pari passu, or junior debt and lien incurrence

Net debt (C$mm) progression at different Brent oil price scenarios

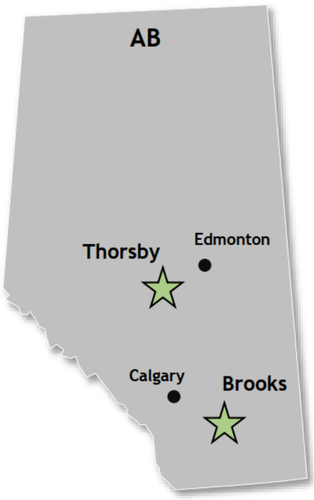


Source: Company Data; H&P estimates

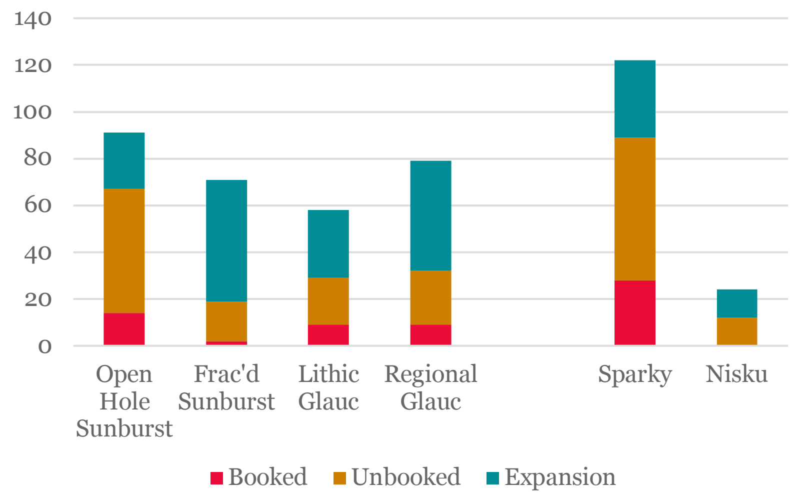
The size of the RCF is based on PDP valuation in April and November each year. Given reserves are expected to grow over the next 1-2 years and the company is expected to generate positive FCF, it is likely that the size of the facility could be increased. We see Calima as having an under-levered balance sheet (0.5x net debt to cashflow based on debt at deal close and annualised H2'21 cashflow). In our base case net debt reaches zero in 2022 – the guidance from the company is that it expects to move to a C$4.5mm net cash position by YE'22 under its base case assumptions.

Alberta assets

Alberta assets map



Drilling locations by play for Brooks (left) and Thorsby (right)

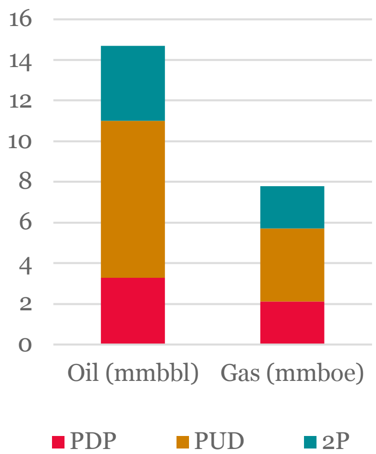


Source: Company data

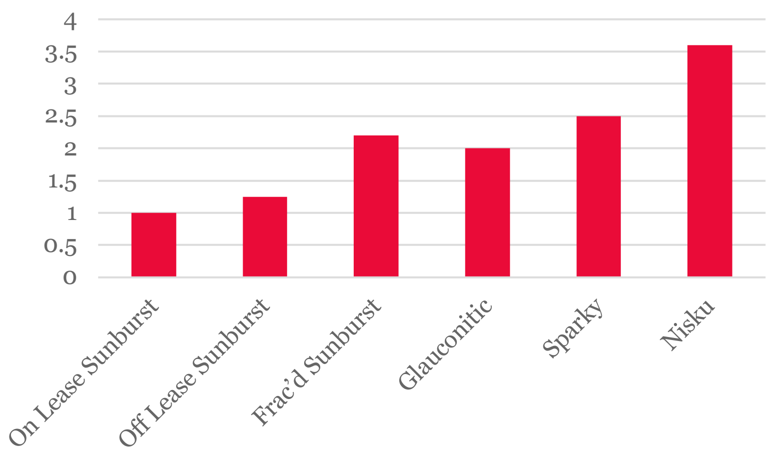
In this section we analyse in detail the newly acquired Blackspur assets. We run through a detailed valuation of the assets demonstrating significant upside to what Calima paid, even at lower oil prices. At US$45/bbl WTI there is the potential to keep production flat, given a 1P reserve life of >17 years whilst still generating some free cashflow. This is a function of the high percentage of oil, low operating costs and existing tax losses.

In any higher oil price scenario, there is significant growth potential. The chart above shows the large number of potential drilling locations and well costs are low to moderate as shown on the bottom right chart. There is the potential to grow to over 10kboe/d later this decade, without outspending cashflow, at current oil and gas prices.

Blackspur reserves (mmboe)



Estimated well cost by type (C$mm)



Source: Company data

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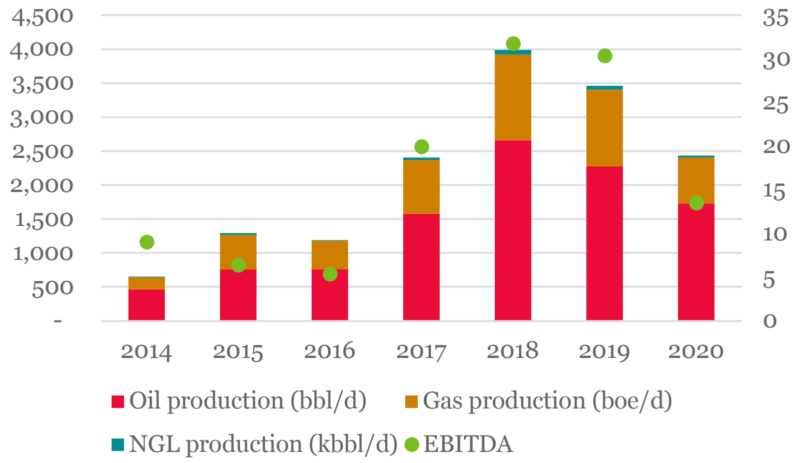
History

Blackspur historical production (boe/d) and estimated EBITDA (C$mm)



Source: Company data, H&P estimates

Blackspur was a growth-oriented oil producer focused on conventional, shallow oil development in Alberta. Both its core areas feature stacked regional and channel sands across multiple zones. ~C$80mm has been raised in four tranches since 2012 and several acquisitions and dispositions have been executed to date totalling ~C$74mm in value. There has been a significant infrastructure spend to date of ~C$20mm with capacity in place to accommodate >12kboe/d without additional material spending.

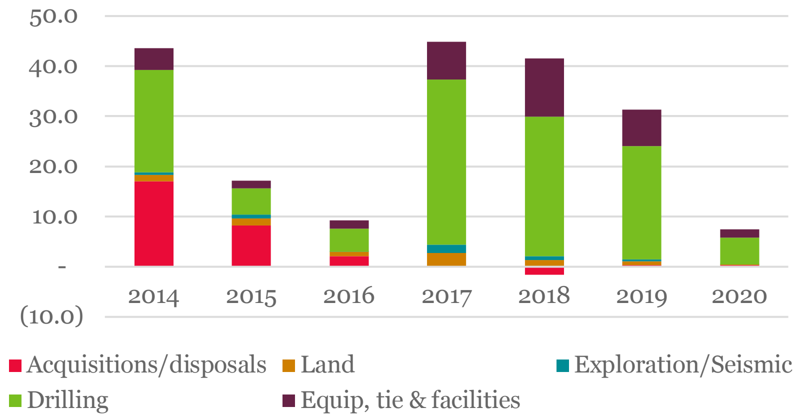
The company was originally started in 2012 through the recapitalisation of a small private company producing just 80bbl/d. In 2014, the company identified the Brooks acreage and raised C$32mm from private equity to acquire and fund development of the assets, ending the year with 1,200boe/d of production.

The Sunburst shallow oil horizon was viewed as an overlooked play given the market's focus on shallow gas in the mid-2000s. The Blackspur strategy was horizontal exploitation of vertically-defined, large pools of oil in place, with low recovery factors to date. Blackspur grew through a combination of organic exploitation of the acreage and a series of small bolt on acquisitions. It also developed a new play concept to develop the Thorsby acreage through multi-fraced horizontal wells. By 2017/18 production had grown fourfold to reach 5,000boe/d at peak, generating ~C$30mm of EBITDA in 2018.

In late 2018 the company was hit by extremely wide price differentials between Western Canadian Select (WCS) and US WTI crude significantly impacting the economics and causing Blackspur to cut back on drilling in 2019, to get back to <2.0x net debt / cash flow. It was due to resume drilling in 2020 with a plan to return to 5,000boe/d, however COVID put a spanner in the works. As a result of the lower oil prices and lower production (2020 exit production of >2,600 boe/d), in 2020 debt to cash flow metrics expanded out and Blackspur's lender put pressure on it to cut debt and examine strategic options. There were various offers on the table and Calima was chosen as the best combination of price and the fact that a large proportion would be paid in equity: both preserving the upside potential from the asset as well as providing possible liquidity to the private equity owners of Blackspur.

We see Blackspur's modelled type curves as reasonable given that they include all the wells drilled (as opposed to some companies that tend to show their best wells). There is the risk of type curve degradation over time as most companies tend to drill their best locations first, somewhat offset by learnings from prior wells and improve completion designs. In fact, at both Brooks and Thorsby, the well results to date suggest that there is upside to the reserve consultant's type curves.

Blackspur historical capex (C$mm)



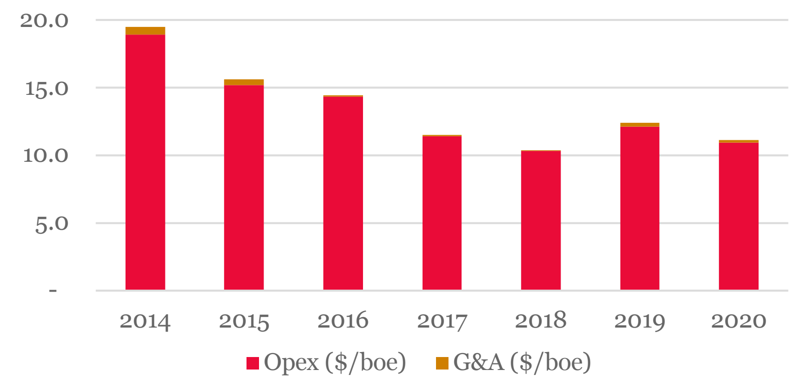
Source: Company data, H&P estimates

Blackspur strategy

Blackspur had balanced a strategy of small acquisitions/dispositions with a delineation drilling focus at Brooks and Thorsby. The management team have been successful in spotting high return overlooked oily plays in Alberta and using horizontal wells and low intensity fracturing of the wells. It has also managed to pinpoint some of the best quality acreage in these areas, for example one of its Sunburst wells is thought to be the best well in the play. Operational successes and learnings to date have now positioned the assets for growth, which are largely derisked with existing wells and extensive 3D seismic data.

Blackspur has proven itself to be an extremely low-cost operator in Western Canada, with production plus transportation costs of ~C$10/boe, which we believe is in the top decile of producers. For example, the assets it bought from Lightstream originally had opex of C$23/boe.

Blackspur historical operating and G&A costs (C$/boe)



Source: Company data, H&P estimates

It has also been focused on low capex plays with high returns, such as the Sunburst with costs to drill, complete and tie-in the wells of just C$1mm. The low opex and capex leads to IRRs of >200% at our US$60/bbl Brent base case forecast. G&A has historically also been low running at around C$2-2.5/boe.

Furthermore, the company has shown itself to be adept at acquiring non-core assets from larger companies and adding small packages of acreage to its existing asset base having completed around a dozen deals.

It has also been innovative in finding a solution to reduce the extremely high costs for treating its sour (high sulphur) gas. It was previously paying C$1.40/mcf to treat the gas (higher than the gas price has been at times) and managed to reduce this down to C$0.4/mcf using a newly developed technology and potentially developing a new business at the same time (see H_2Sweet on page 42).

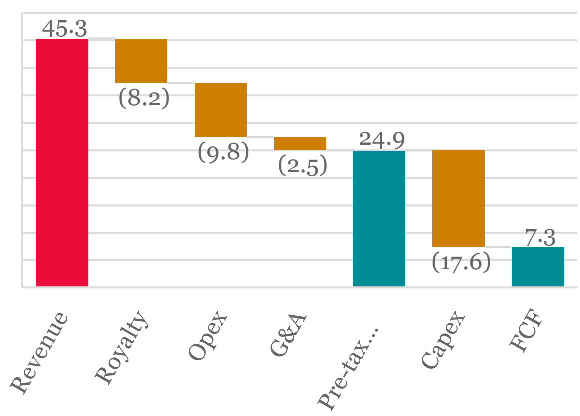
Carbon cost

Blackspur is exempt from Canada's Federal Carbon Tax legislation, as an early adopter of the Alberta TIER program. It started reducing emissions annually from 2020 through various initiatives, and that allows it to not pay carbon tax. However, if it does not reduce emissions by the required percentage it will have to pay carbon tax, or purchase carbon credits. In 2019, Blackspur emitted 10.2kt venting, and 10.3kt tonnes of CO2 from stationary fuel combustion. This equates to 0.01623 tonnes of CO2 per boe in 2019.

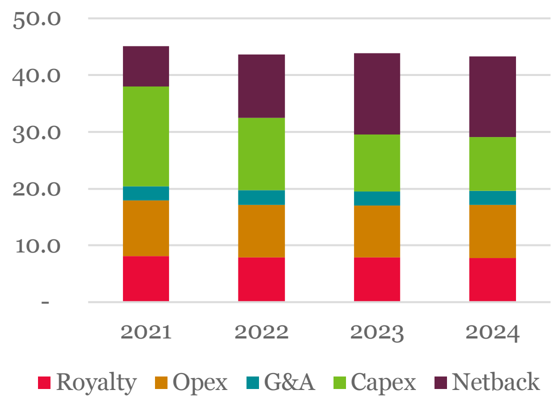
Under the TIER program, Blackspur is to reduce emissions from stationary fuel combustion by 10% in 2020 from the 2019 consumption intensity benchmark measured in tCO_2e/m^3OE produced hydrocarbons or will have to pay carbon tax or purchase carbon credits to offset overage.

Netback economics

2021E netbacks (C$/boe)



2P development: 2021-24 FCF netbacks (C$/boe)



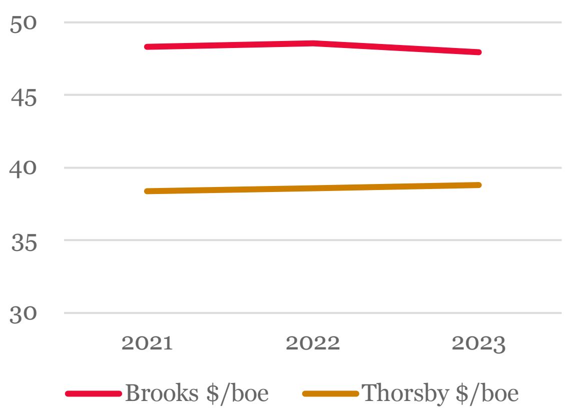
Source: H&P estimates

We run through the overall economics of the Alberta assets, which are shown at our base case assumptions (see page 14 for full details): an oil price of C$56/bbl WCS and a long-term AECO gas price of C$3.4/mcf (C$21/boe). We estimate a royalty rate of 18% on average. The charts show that the assets will generate a healthy C$25/boe of pre-tax CFFO in 2021 and this stays steady over time. The FCF generation at current capex levels is C$7/boe and this will increase over time as production grows and capex moderates under the base case plan, however there is clearly room to grow faster within cashflow.

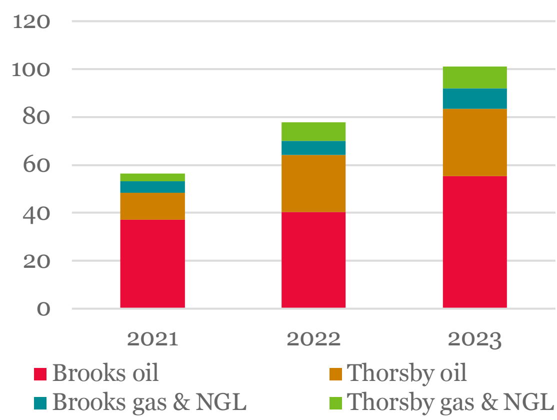
The realisations on Brooks are higher than Thorsby as there is currently a lower percentage of gas from Brooks (gas pricing is less than 50% of oil on a barrel of oil equivalent basis). However, the percentage of oil is expected to be higher in newer Thorsby wells, hence the increase in realisations in 2022. Also, Thorsby oil sells at around $6/bbl lower than Brooks given crude quality and logistics. The chart on the bottom right below shows that almost 90% of the revenue comes from oil.

Realisations

Realisations (C$/boe) excluding hedging impact



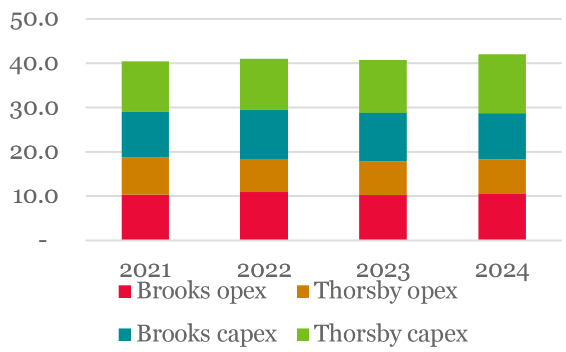
Split of revenues (C$mm) by area and phase



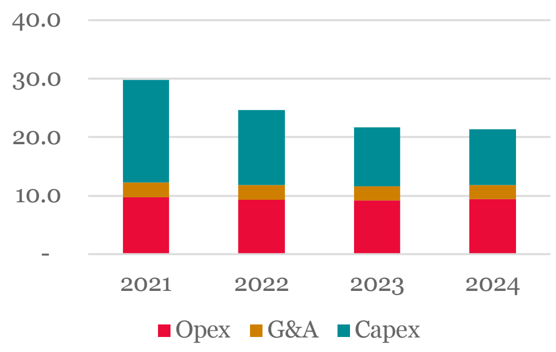
Source: H&P estimates

Costs, capex and tax

Opex and capex (C$mm)



Opex, G&A and capex (C$/boe)



Source: H&P estimates

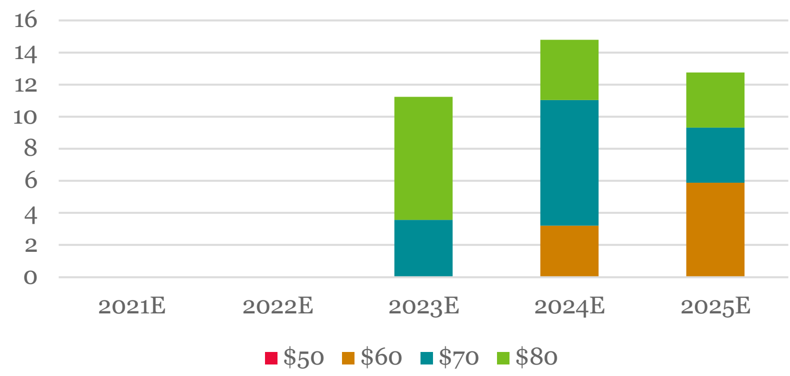
Operating costs are under C$10/boe of which around C$8/boe are lifting costs and C$2/boe are transportation costs. We expect that there is downside risk to the operating costs, as production grows, given that part of the operating costs are fixed and this cost base will decline as a proportion of the total as new wells are brought on line. Blackspur's G&A has historically also been low, running at around C$2-2.5/boe and there is very little G&A within Calima's existing operations.

The major capex is associated with drilling, completion and tie-in of new wells, which take 6-12 days to drill. Costs range from C$0.7 to C$3.1 million depending on whether they are Sunburst, Glauconitic or Sparky wells. Maintenance capital for the PDP wells is budgeted at around $50k per annum so in total for the ~60 wells is around C$3mm p.a.

There is also expected to be a small amount of asset retirement obligations (ARO) expenditure for the decommissioning of older wells and infrastructure. This is estimated to be around C$0.5mm per annum from 2021. The 2020 cost is covered by a Government subsidy.

We do not expect to see Calima paying cash tax until 2024 on our base case assumptions. This is a result of the existing tax pools of >C$50mm that are available to offset against production from Blackspur and Calima's existing operations. Moreover, the investment that is going into the assets over the next couple of years also builds up a further tax shield.

Cash tax payable (C$mm) per annum at various Brent prices (US$/bbl)

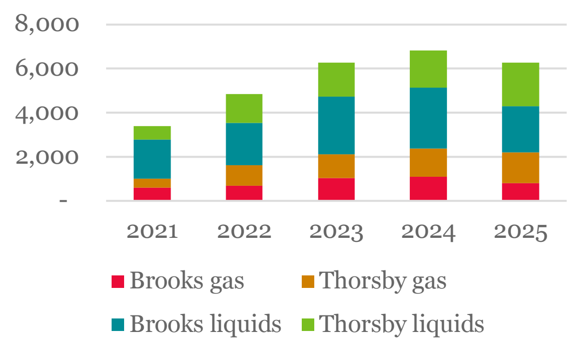


Source: Company data, H&P estimates

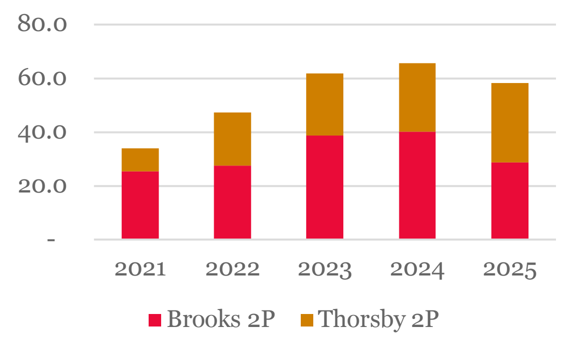
Base case development plans (2P reserves)

The 2P case leads to significant cashflow generation of over C$60mm in 2023. With further drilling there is the potential to grow production to 10kboe/d.

Production profile by phase and area



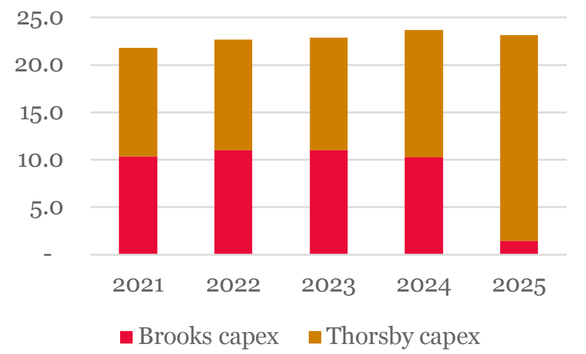
Pre-tax cashflow by asset (C$mm)



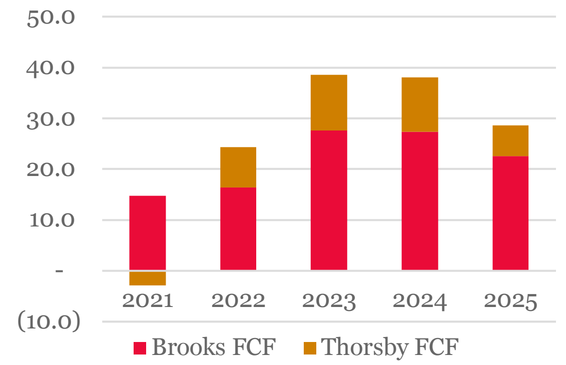
Source: H&P estimates

Capex remains well within cashflow to provide the growth to 2023, with an average of >C$25mm p.a. of FCF from 2021-25, creating ample room for further growth or shareholder returns.

Capex by area (C$mm)



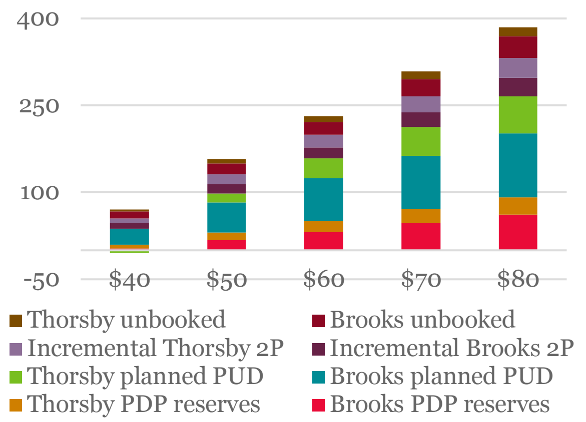
Post-tax free cashflow by asset (C$mm)



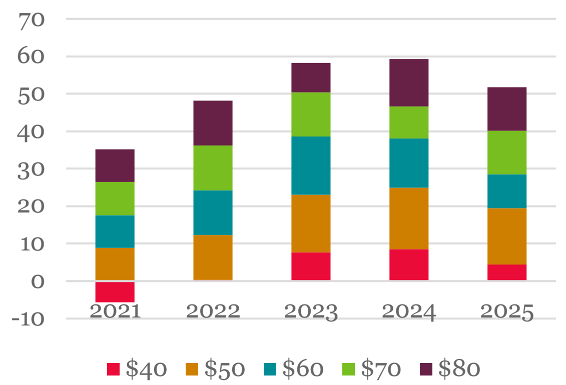
Source: H&P estimates

The charts below show the sensitivity of NPV10 valuation and FCF under the base case drilling scenario to various oil prices.

Risked NPV10 (C$mm) by reserve type vs Brent



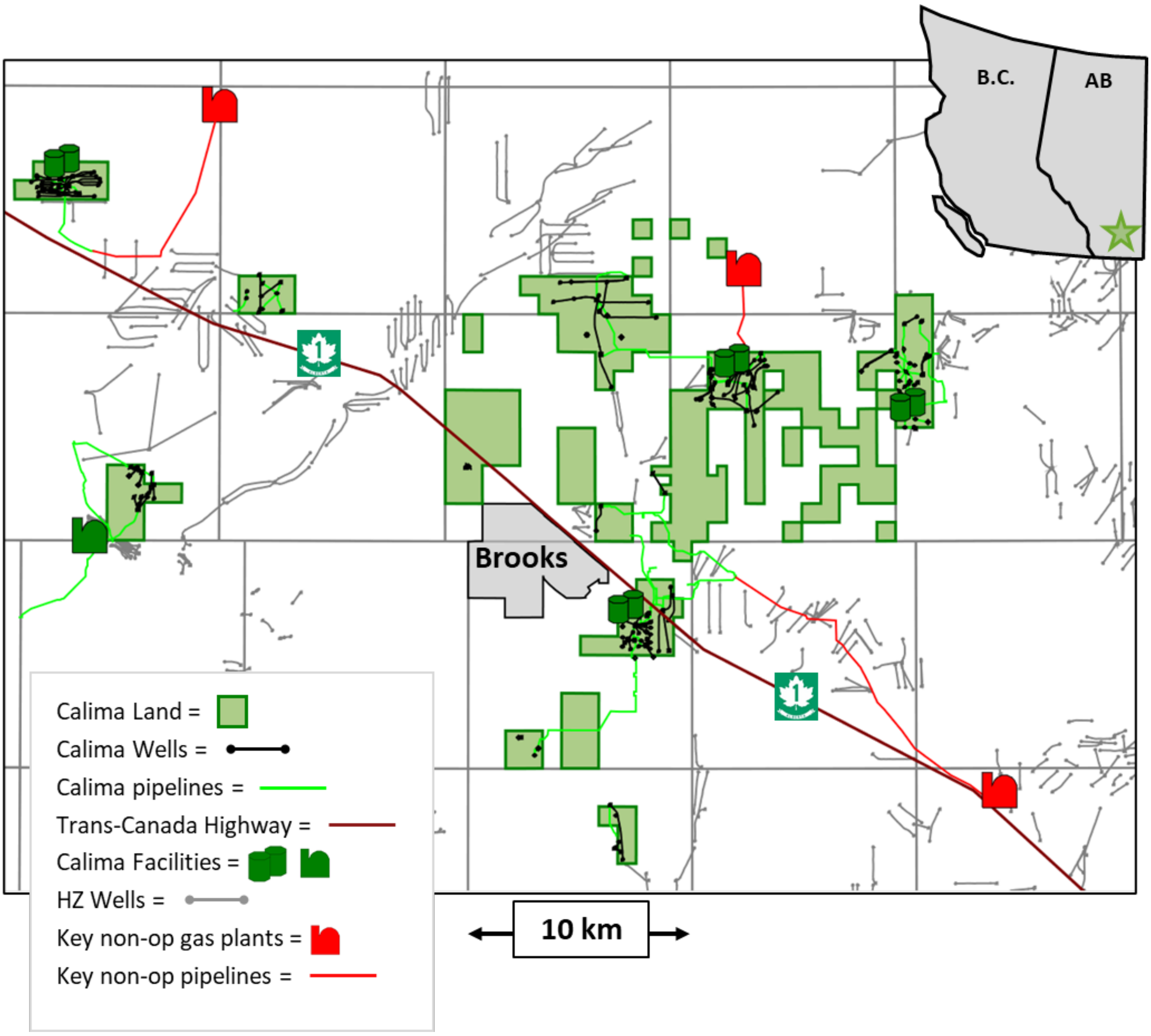
Post-tax free cashflow Brent price sensitivity (C$mm)



Source: H&P estimates

Brooks

Brooks acreage map



Source: Calima

Brooks is the more developed and valuable acreage position. It generates significant cash flow at current oil prices (~C$15mm in 2021 at US$57/bbl WTI) given the existing low cost production base and premium oil pricing relative to WCS. The core Sunburst inventory is the quickest payback and highest return in the portfolio (>200% IRR and <6 months payback even at $45/bbl WTI). As a result there is strong growth potential, whilst generating excess FCF. At current oil prices, for Brooks alone, we see the combined NPV10 unrisked value of the PDP reserves (C$32mm) and PUD development (C$83mm) as worth almost double the acquisition cost of ~C$60mm. At current oil prices, Brooks could grow at a CAGR of 13% to 2030 from its existing 2P drilling inventory whilst generating >C$200mm of pre-tax FCF over the period.

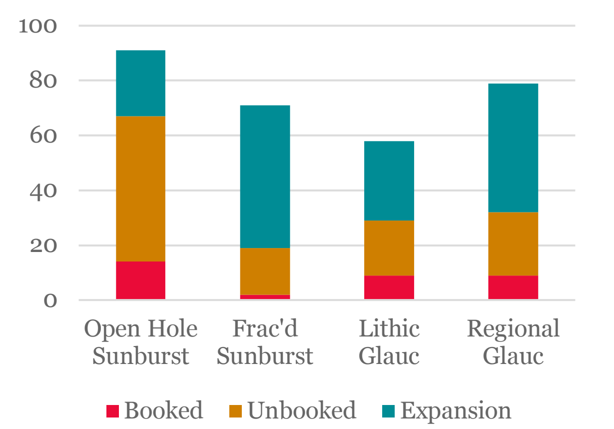
Blackspur has established a core position of land with ~83 net sections (a square mile of land) and significant infrastructure that creates a foundation for growth and expansion with year-round access. Blackspur holds an 94% WI in Brooks land, of which ~68% is undeveloped. This includes ~6 net sections of 0% royalty lands and ~4 net sections of approximately 10% royalty lands, versus the average royalty of 18%. 25 Sunburst wells have been drilled to end-2020 of which 22 have been productive. The average API at Brooks is 28º API, which is lighter than average for Canada.

The Brooks asset averaged production of a net ~1,860 boe/d in Q4'20 with a 94% working interest. Blackspur has drilled 48 wells to date. Blackspur has booked 9mmboe of 1P reserves of which 3.4mmboe are proved developed; 2P reserves are 11.6mmboe. This is a 1P reserve life of >13 years and a 2P reserve life of 17 years, which demonstrates plenty of organic growth potential. Its existing infrastructure (C$15mm spent to date) can process up to 7,000 bbl/d oil.

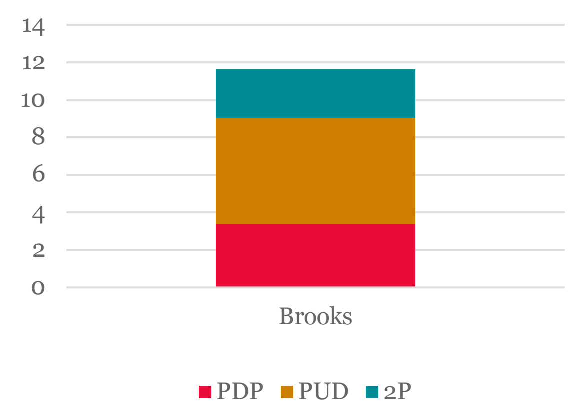
Blackspur has identified, delineated and developed multiple oil pools in Brooks. It has an inventory of 147 net drilling locations of which 35 have been booked. There is the potential to add offsetting ~49 net sections through Crown and freehold leasing, contributing an additional 152 net locations. Production comes from the Lower Mannville Sunburst and Upper Mannville Glauconitic formations. All the oil pools have already been defined by existing vertical wells most of which had been drilled 30-40 years ago. Blackspur has been able to take the vertical wells' data along with 3D seismic and drill horizontal wells to produce the oil.

Shallow formation depths (~950m to ~1,150m TVD) mean that the Sunburst can be developed at low cost (<C$1m per well). Also, it is a conventional play that does not require fracturing of the wells. Its owned and operated infrastructure provides a resilient cost structure with opex (including transportation) of ~C$10/boe. These factors mean open hole (i.e. no need to frac) Sunburst wells have top tier economics at current pricing. Blackspur's Sunburst drilling inventory maintains positive economics down to ~US$31/bbl WTI (including all drilling costs) providing significant optionality on its 2021 drilling program.

Number of drilling locations by type



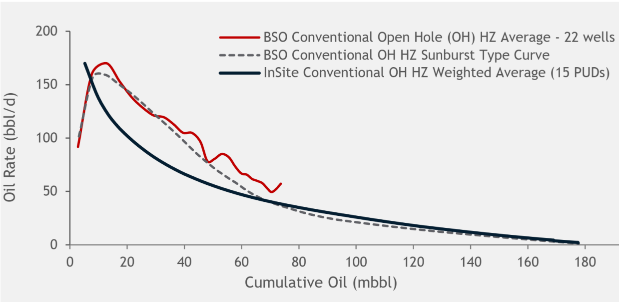
Build up of 1P and 2P reserves (mmboe)



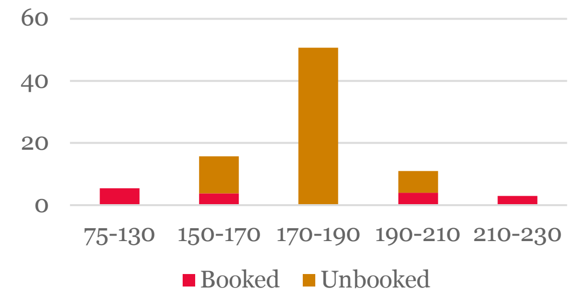
Source: H&P estimates

Future growth from the Brooks asset will come from the 147 net locations that have already been identified. These locations include the booked 16 Sunburst and 17 Glauconitic PUDs with multiple pools still to be delineated. Additional reserves are expected to be realised through the implementation of enhanced oil recovery projects. Blackspur recently initiated a waterflood in the Countess J2J Pool, which is expected to show results in the near term, highlighting the secondary recovery potential of the asset base. This would have been done sooner if not for COVID and should arrest the natural decline through voidage replacement.

Sunburst horizontal type curves and actuals



Inventory by EUR interval (conventional and frac'd)



Source: Company Data

Also Brooks wells have demonstrated significant type curve outperformance in both the Sunburst and Glauconitic reservoirs: the chart above shows the much stronger performance of the 22 wells drilled (red line) versus the type curve from InSite. Therefore we see upside to the production forecasts from higher than expected production from the current drilling programme.

Sunburst play economics

		Blackspur's Conventional	InSite's Conventional	Frac'd
IP90 (boe)	boe/d	186	183	175
IP90 (oil)	bbl/d	139	144	148
EUR (boe)	mboe	235	222	261
EUR (oil)	mbbl	178	178	204
Liquids	%	77%	80%	82%
Well cost	C$mm	1000	1100	2200
1st year opex	$/boe	6.89	7.54	7.06
NPV10*	C$mm	1692	1251	1607
IRR*	%	207%	85%	56%
Payout*	Years	0.7	1.3	1.6
F&D	C$/boe	4.25	4.96	8.43
WTI breakeven	US$/boe	30.8	32.5	35.3

Source: Company Data; US$30/bbl WCS, C$2.50/mmbtu AECO and 1.325 CAD/USD

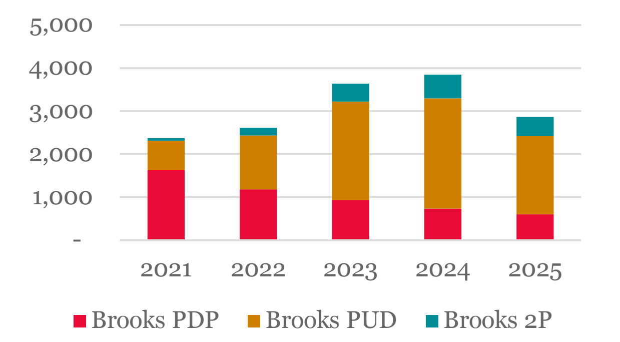
The table above shows the key type curve data for the Sunburst formation wells on the Brooks acreage. The 22 Sunburst wells drilled by Blackspur and the type curve based on this shows higher production than its reserve consultant InSite's projections over the initial months, also a lower well cost and lower operating costs. All this leads to a significantly higher IRR and NPV.

The total development cost plus operating cost is just C$11/boe leading to a WTI breakeven of US$31/boe. Each Sunburst well has an NPV of C$1.7mm at a conservative oil price of US$45/bbl WTI. On Blackspur's type curve the 16 PUD wells alone have a pre-tax NPV10 of C$27mm (C$7/boe) or the equivalent of AUD ~0.3c/sh. Using our forecast oil price of US$60/bbl Brent (US$57/bbl WTI), we estimate a post-tax NPV/boe that is more than double this (C$15/boe).

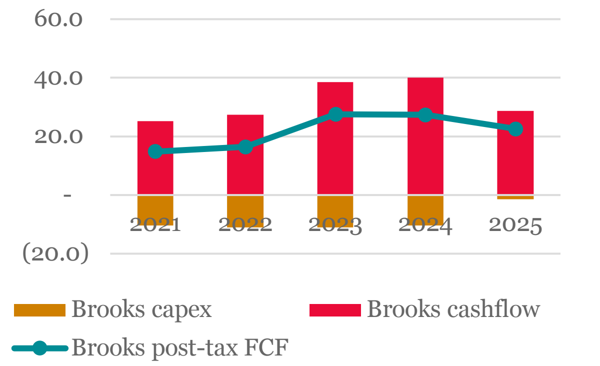
On an absolute basis the frac'd Sunburst wells shows strong standalone pre-tax economics with a WTI breakeven of $35/boe and >50% IRR at US$45/bbl WTI. However, the economics are worse than the conventional Sunburst, primarily due to the higher well cost of C$2.2mm versus C$1mm but only 18% higher EUR. If oil prices are sustained at the current levels (~US$60/bbl WTI), we see the potential for more frac'd wells to be drilled over the next few years. Also, Blackspur has several high-graded Glauconitic locations that may receive capital allocation in the next few years. The regional Glauconitic play is also a strong candidate for waterflood and an enhanced oil recovery project.

Brooks 2P base case development

Planned production (boe/d)



Cashflow and capex (C$mm)

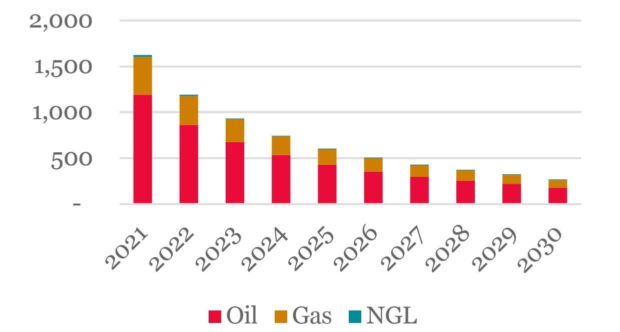


Source: Company Data

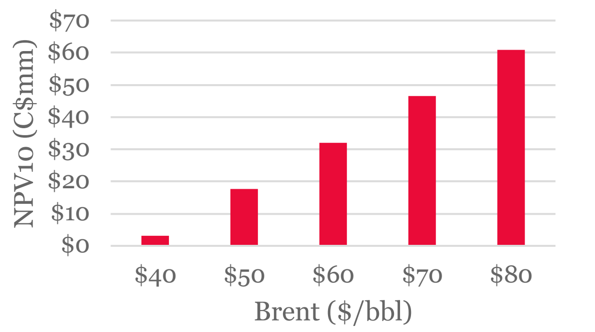
Our base case for Brooks development uses the 2P reserves given that we see these as highly economic in the current oil price environment. A moderate development of the 2P reserves sees production grow to close to 4kboe/d whilst generating significant free cashflow. Over the period to 2025 we expect >C$100mm of post-tax free cashflow generation. Our total unrisked 2P reserve valuation for Brooks is C$140mm.

Brooks PDP valuation

Brooks PDP production (boe/d



PDP value ($Cmm) at various Brent prices (US$/bbl)



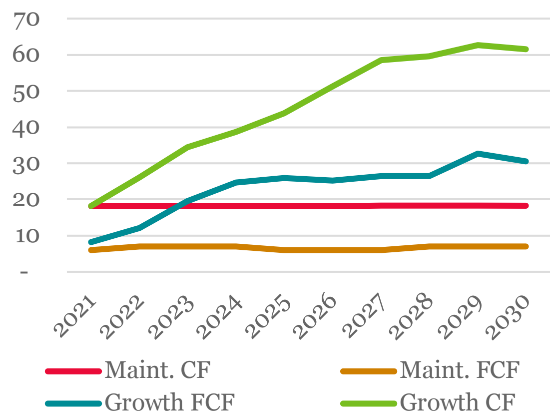
Source: Company Data

Brooks has production from around 42 existing wells with total proved reserves of 2.7mmboe (71% oil). 2021 PDP production is expected to be around 1.5kboe/d and this should generate C$16mm in CFFO on a full year basis (Calima will only access the cash flow from May 2021). Our base case valuation is an NPV10 of C$12/boe or C$32mm. The valuation is highly sensitive to oil prices as the majority of the NPV is generated in the next 3 years and Calima is not expected to pay any tax over this period. The risk to the production profile is very low given this is conventional production from existing producing wells.

Brooks development scenarios: low case (US$45/bbl WTI; maintenance spend) versus high case (US$57/bbl WTI and growth capex)

Production (boe/d) and wells drilled p.a. (RHS)

Cashflow and free cashflow (C$mm)



Source: Company Data

Above we examine the production and cash flow outlook in a low oil price scenario and based on stronger growth than is planned in the current oil price environment.

In a lower oil price environment of US$45/bbl WTI, to keep production flat at Brooks requires around 3 wells per annum for a total capital cost of C$5mm. This would still allow Calima to generate around C$7mm of free cash flow from the asset out until the end of the decade with >115 drilling locations remaining.

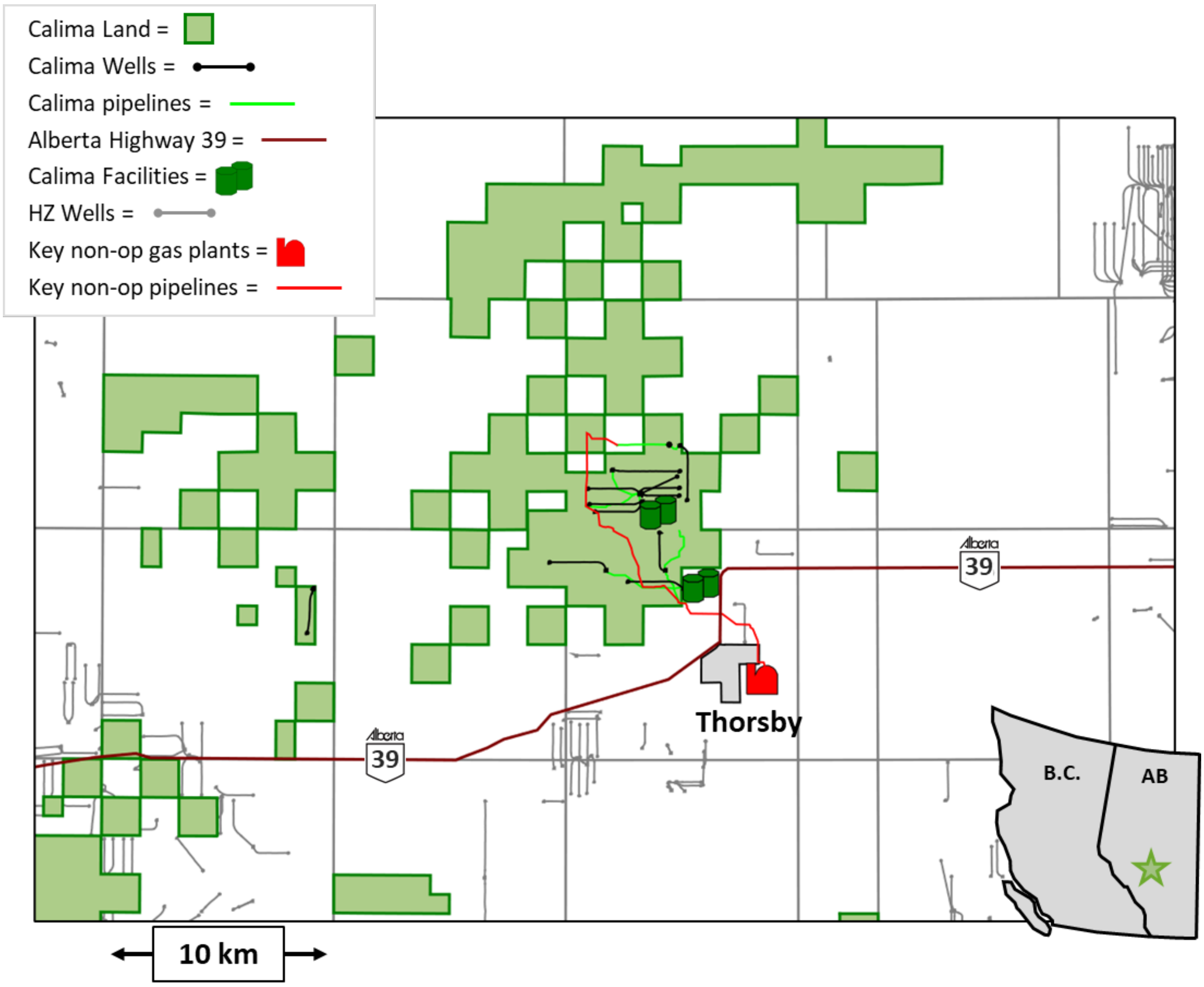
At higher oil prices of US$57/bbl WTI, there is the potential to grow production to 6kboe/d (13% CAGR) from existing inventory drilling around 12 wells per annum on average with a spend of C$22mm per annum. This can all be done whilst spending within cashflow and will generate >C$200mm of undiscounted pre-tax FCF out to the end of the decade.

Recent drilling

On 3 March 2021, Blackspur spudded the first of a 3 well drilling campaign targeting the Sunburst Formation. The new wells were drilled to an average total depth of 2,021 m with an average horizontal leg length of 770 m. Drilling was completed on 21 March, with all wells drilled under budgeted time and cost: the budget was C$2.4mm in total. Blackspur then performed completion procedures for the three wells, followed by the equipping and tie-in process. The three wells will be in the "clean up" stage when they are first brought on, producing water and drilling fluid at the beginning of the flow back period. Initial production rates after 45 days, (IP45) for the three wells will be known in early May 2021. At US$60 WTI, only assuming standard type curve production, these wells are anticipated to pay-out in under 6 months.

Thorsby

Thorsby acreage map



Source: Calima

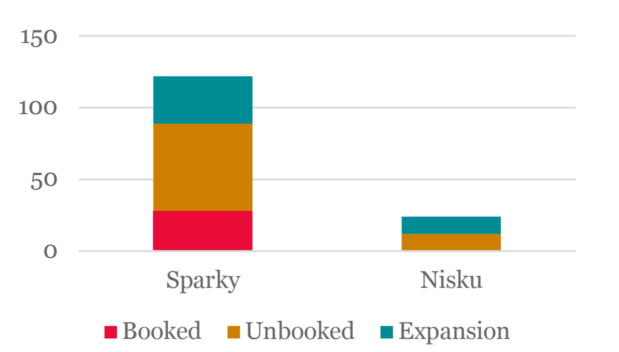
At Thorsby the growth potential is larger and more impactful to production, however higher capex is required, it is historically more gassy and the returns are lower than at Brooks. On a standalone basis the economics are attractive using conservative type curves and at more moderate oil price levels than at present. However, there is the potential for significant type curve outperformance (e.g. 67% IRR from Blackspur's Tier 1 type curve versus 30% from the reserves consultant, both at US$45/bbl WTI) and the possibility to boost production and returns through increasing the frac size. Also, there is the potential for very strong returns at current oil prices. The Thorsby area can provide stable and consistent production and cash flow or be a platform for meaningful growth. Blackspur has advanced and de-risked completion techniques with recent wells highlighting a significant improvement in productivity and economics.

Thorsby is a consolidated land base of ~108 net sections that is being efficiently developed through a network of multi-well pads. Blackspur holds an 88% WI in Thorsby land, of which ~92% is undeveloped. The Thorsby asset has year-round access and production averaged ~740 boe/d in Q4 2020 from the Sparky Formation. Blackspur has drilled 11 wells to date and spent over C$5mm building infrastructure in the area giving it processing capacity of 3,000 bbl/d of oil. The Sparky play is more conventional in nature with little historical drilling. It is a hybrid of conventional reservoirs being developed as a resource (i.e. shale type) development. The main oil pool in the area is large at 36 sections. Results to date are competitive with other economic oil plays in the Western Canadian Sedimentary Basin.

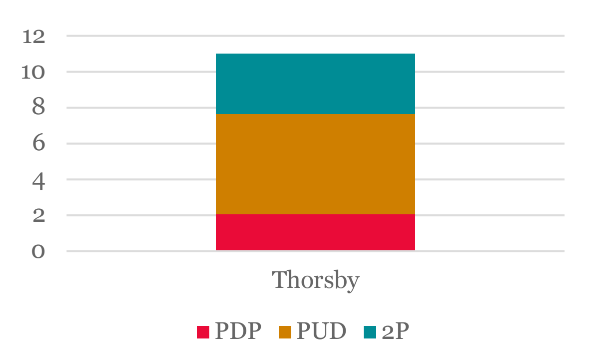
The Sparky Formation in the greater Thorsby area consists of stacked sands that can be greater than 30m thick and hosts medium to heavy grade oil which typically ranges from 14-20° API. Despite being a heavier crude, a high geothermal gradient in the area lowers viscosity and improves oil mobility relative to the regional gradient.

There are currently 2mmboe of PDP reserves at Thorsby from the existing 11 wells. There is a further 5.6mmboe of PUD reserves from 28 Sparky locations and another 3.4mmboe of probable reserves. In total there are 61 unbooked locations giving plenty of development runway for the play. There is the potential to add an offsetting ~22 net sections through Crown and freehold leasing, contributing an incremental 45 net locations. The early stage of the development is demonstrated by Blackspur having a 1P reserve life based on Q4'20 production of 28 years and a 2P reserve life of over 40 years.

Number of drilling locations by formation



Build-up of 1P and 2P reserves (mmboe)



Source: H&P estimates

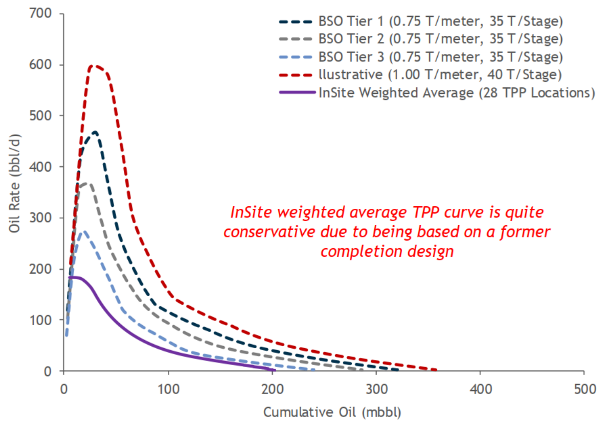
After entering the play in 2015, Blackspur developed a new play concept on its Thorsby acreage to test a mile long multi-stage frac'd horizontal well. The pace of development at Thorsby has been slower than at Brooks as Blackspur looked to refine its concept and delineate its acreage, rather than focusing on production. It has now reached the stage where it can move into factory-style development, after having proven the play and its viability. The assets are development ready and can be scaled up quickly with the use of existing pads and facilities. The plan now is to drill from multi-well pads.

Significant upside potential remains in drilling and completion refinement, such as the use of monobores: using the same diameter of casing (after surface casing) all the way to the toe of the well (or target depth). It provides for quicker spud to rig release. The quicker the wells are drilled, the less they cost. There are also economies of scale with operating costs (including transportation) of C$10/boe.

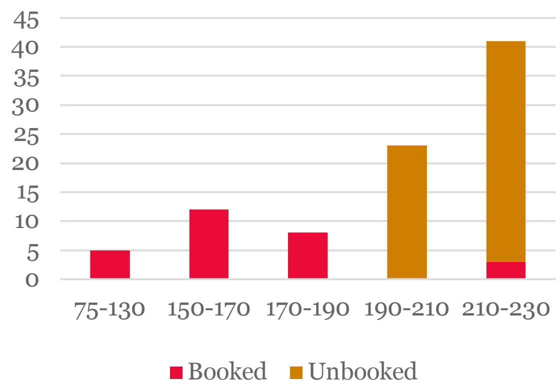
The price realisations in Thorsby tend to be at around C$4/bbl discount to WCS as the API is lower than the average for WCS. If the WCS discount expands out however there is some compensation as the Thorsby discount then tends to narrow.

Thorsby has a long history of delineation and the early vintage wells were gassy. Blackspur encountered a gas charged fault with 3 of its initial wells. However, it was not identified until after the 13-030-50-01W5 well, after it obtained 3D seismic and was able to map the fault. After this, GORs have been normal. Blackspur started drilling the play in 2014 at a 1-2 well/year rate, and key learnings were obtained in 2018 when it was able to crack the code for economic development.

Sparky horizontal type curves



PDP and PUD locations by EUR interval



Source: Company Data

Blackspur's understanding of the geology has substantially increased over time allowing it to optimise the well design to improve the economics. Increased tonnage has improved well results over time and productivity directly correlates to proppant intensity. Therefore, the new completion design exhibits improved performance.

The most recent wells into the Sparky formation have been completed with a higher frac intensity, which has translated into significant type curve outperformance: both higher initial production rates and higher EURs (ultimate recovery). As a result, the there is significant upside to the type curve used by the reserves consultant, which can be seen on the top left chart above. Also, the chart on the top right shows that that the majority of unbooked locations all have much higher EURs.

Out of the total 66 Sparky locations, 13 are classified as Tier 1, 25 as Tier 2 and 28 as Tier 3. The tiers are a direct function of proppant intensity. It is expected that a 1 tonne/metre well (or equivalent of 40 tonne/stage at 40 stages) will outperform the last three wells drilled. This illustrative well is shown by the red dashed line on the top right chart.

Tier 1 are planned future wells incorporating all technical learnings over the wells drilled to date and based on the best 2 wells drilled to date (away from the fault). Tier 2 adds a third well with sand issues and downtime but still consistent with all the learnings in tier 1 (away from fault). Tier 3 includes all the tier 2 wells plus 3 additional wells with lower frac tonnage and closer to the fault which have higher GOR's, thus more risk in that it includes wells that are not representative of future drilling. Tier 3 are based on 30-35 T/stage & 0.5 – 0.8 T/m. Blackspur has optimised completion design and has 3D seismic to avoid the fault.

Play economics

		BSO Tier 1	BSO Tier 2	BSO Tier 3	InSite Avg	Illustrative 40 T/Stage
IP90 (oil)	bbl/d	336	274	182	183	460
EUR (boe)	mboe	419	362	351	331	452
EUR (oil)	mbbl	320	287	240	202	358
Liquids	%	78%	80%	70%	63%	80%
Well cost	C$mm	2500	2500	2500	2500	2800
NPV10*	C$mm	2388	1886	1296	1055	2878
NPV10*	C$/boe	5.7	5.2	3.7	3.2	6.4
IRR*	%	67%	50%	31%	30%	77%
Payout*	Years	1.5	1.7	2.6	2.8	1.3
F&D	C$/boe	5.97	6.9	7.13	7.54	6.2
WTI breakeven	US$/boe	34	35.1	36.77	38.23	33.22

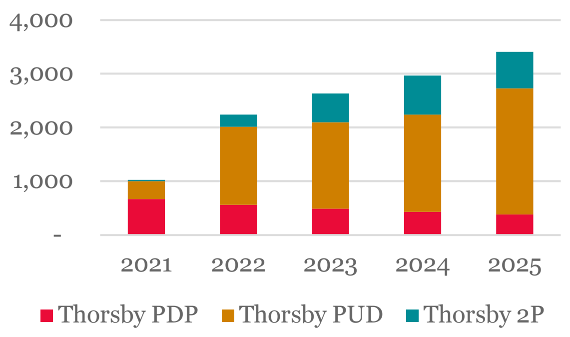
Source: Company Data; US$45.00/bbl WTI, C$2.50/mmbtu AECO, US$15.00/bbl WCS differential and 1.325 CAD/USD

The table above shows the key type curve data for the wells on the Thorsby acreage. The Tier 1 wells (13 identified) show much stronger economics than the reserves consultant, Insite's average. InSite weighted average TPP curve is quite conservative due to being based on a former completion design. As a result of the enhanced completion design, at the same cost a higher initial production rate (83% higher oil) is expected, a higher EUR (27% higher recovery) and a higher percentage of oil (78% vs. 63%) as the future wells are expected to avoid the fault. This results in a 126% higher NPV of C$2.4mm per well.

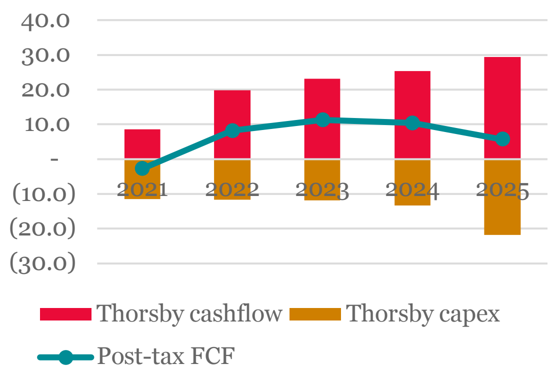
The illustrative curve is based on increasing the frac size to 1 T/m, this increase is planned on future wells. The illustrative 40 T/Stage scenario has around 10% higher capex but 20% higher NPV and an IRR of 77% versus 67% for the Tier 1. Therefore, if it can prove the upside potential for the 40/T stage well design, there is upside to both reserves and the value per barrel. If oil prices are sustained at the current levels (~US$60/bbl WTI), we see the potential for more Sparky wells to be drilled over the next few years than in the base case plan. In absolute terms the Tier 1 NPV and returns are still lower than the Sunburst conventional but more impactful in terms of production growth.

Thorsby base case development

2P Planned production (boe/d)



2P Cashflow and capex (C$mm)

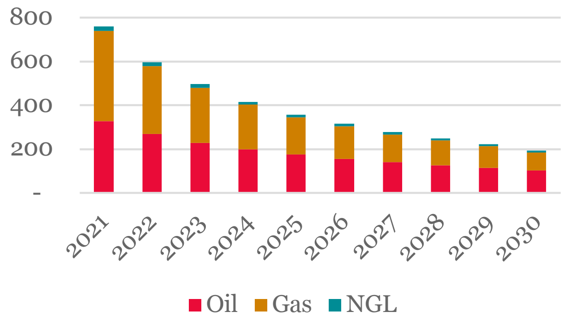


Source: Company Data

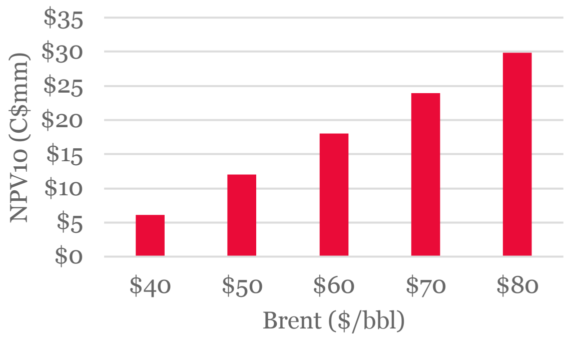
Our base case for Thorsby development uses the 2P reserves given that we see these as highly economic in the current oil price environment. A moderate development of the 2P reserves sees production grow to close to >3kboe/d whilst generating significant free cashflow from 2022 onwards. Over the period to 2025 we expect >C$30mm of post-tax free cashflow generation. Our total unrisked 2P reserve valuation for Thorsby is C$82mm.

Thorsby PDP valuation

Thorsby PDP production (boe/d



PDP value ($Cmm) at various Brent prices (US$/bbl)

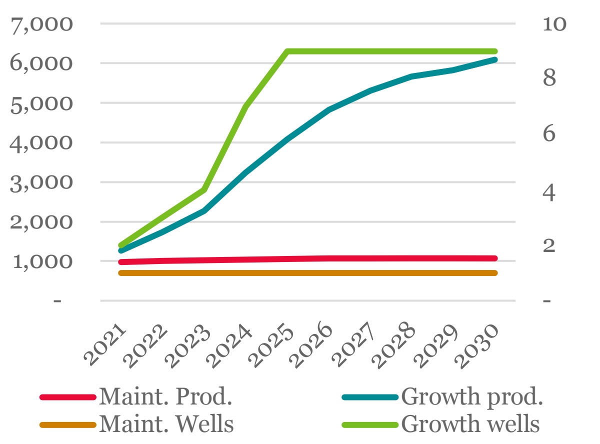


Source: Company Data

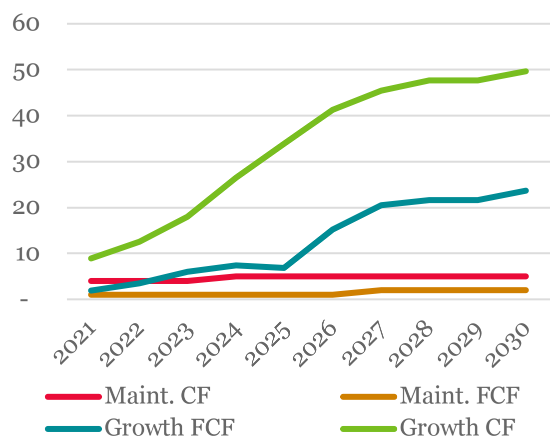
Thorsby has production from around 11 existing wells with total proved reserves of 2.1mmboe (44% oil). 2021 PDP production is expected to be around 0.6kboe/d and this should generate C$5mm in CFFO on a full year basis (Calima will only access the cash flow from May 2021). Our base case valuation is an NPV10 of C$9/boe or C$18mm. The valuation is sensitive to oil prices as the majority of the NPV is generated in the next 3 years and Calima is not expected to pay any tax over this period. The risk to the production profile is very low given this is conventional production from existing producing wells.

Thorsby: low case (US$45/bbl WTI; maintenance spend) versus high case (US$57/bbl WTI and growth capex)

Production (boe/d) and wells drilled p.a.



Cashflow and free cashflow (C$mm)



Source: Company Data

In a lower oil price environment of US$45/bbl WTI, to keep production flat at Thorsby at around 1kboe/d requires just 1 well per annum for a total capital cost of C$3mm. This would still allow Calima to generate around C$1mm of free cash flow from the asset out until the end of the decade with 85 drilling locations remaining.

At higher oil prices of US$57/bbl WTI, there is the potential to grow production to >6kboe/d (24% CAGR) from existing inventory drilling around 7 wells per annum on average with a spend of C$20mm per annum. This can all be done whilst spending within cashflow and will generate >C$125mm of undiscounted pre-tax FCF out to the end of the decade.

Thorsby Nisku and Duvernay potential

There is resource potential in the Nisku and Duvernay formations on the Thorsby acreage, supported by offsetting results. However, there are no proved reserves or booked locations currently associated with either play and we do not currently carry any value for the acreage position.

There are 12 Nisku Formation wells identified, which is a high impact conventional light oil (~40° API) opportunity that has strong economics with the potential for blending opportunities. Nisku Formation is a Devonian-age platform carbonate They are conventional reservoirs, which have been traditionally produced with vertical wells. Recent horizontal wells targeted areas of low recovery and pool step-outs. Even though the curve is conservative with respect to its analogue, economics are strong with an IRR of 92% and a payout value of only 1.1 years at $45 WTI.

Blackspur has Duvernay prospectivity on its Thorsby acreage and there has been nearby drilling from Crescent Point targeting the play. Recent activity offsetting Blackspur acreage establishes the lands within the oil window. However, although the standalone economics may work in the current oil price environment, the well costs are very high (~C$10mm to drill and complete) and it has plenty of higher return opportunities on its acreage, it is unlikely to have any capital devoted to it in the near-term. Longer-term there is the potential to develop the acreage or more likely in our view is that Calima elects to sell the rights to the Duvernay to another player with bigger pockets that is more focused on this particular play.

H_2Sweet

Blackspur along with Envirotech (a fabrication/chemical production innovator) together own a company called H2Sweet, which was incorporated in 2019. It is a unique combination of a collaboration between industrial processing and the Alberta Energy industry. They have developed a technology to remove sulphur from oil and gas production at much lower cost than competing technologies and also significantly improve the ESG credentials of a project, through the avoidance of CO2 production and through a much safer and environmentally friendly process.

So far, the technology has only been used internally by Blackspur but there is a large opportunity to deploy this technology into oil and gas projects worldwide with the potential for material licensing revenues. We only currently include the book value of the investment (C$0.4mm) but we see the potential for the business to be worth multiple times this amount. We do not expect any significant capital expenditure to be required and there is the potential for a high multiple licensing model.

Hydrogen sulphide (H_2S) is a gas commonly found in oil and gas operations worldwide, which is corrosive, carcinogenic and toxic so must be removed from gas streams (known as sour gas when containing H_2S), to maintain safe and effective operations. H_2S is expensive and difficult to deal with from an operational and HS&E standpoint. Technical advancements are rare in this space and H_2Sweet has a solution in Sulfcat®. There is an enormous target market as producers and consumers of sour gas are worldwide and for example the current global market for Triazine alone is $1bn annually.

Comparison of different sulphur removal technologies

Process Feature	Sulfcat®	Triazine	Amine
Low Operating Cost	✓	x	x
Low Capital Cost	✓	✓	x
Low Chemical Consumption	✓	x	✓
Low Energy Consumption	✓	✓	x
Fast Project Delivery	✓	✓	x
Regenerative Reagent	✓	x	✓
Non-Hazardous Reagent	✓	x	x
Minimal Waste Generation	✓	x	✓
High Turndown Capability	✓	x	✓
Adapts to Process Variability	✓	x	✓
Positive ESG Contribution	✓	x	✓

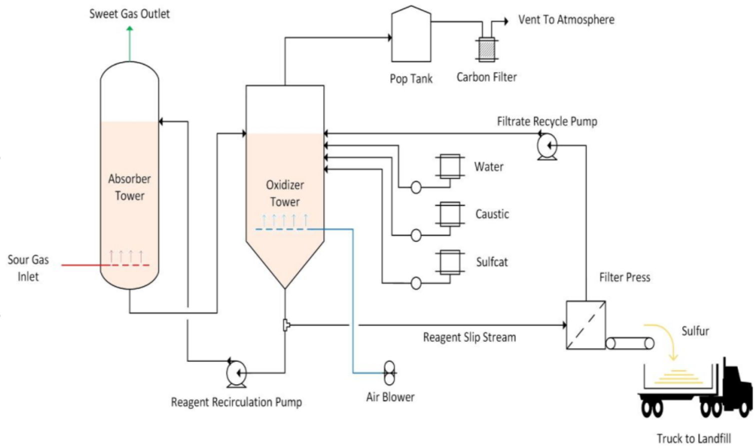
The predominant H_2S removal processes currently utilised by the oil and natural gas industry consist of either Triazine Scavenger Systems (Non-Regenerable) suitable for low volume and concentration applications but which consumes large amounts of toxic chemicals and produces large volumes of toxic waste. The alternative is Amine / Claus Systems (Regenerable) for large scale projects but with high upfront capital costs and high energy/electricity consumption.

H_2Sweet provides third option to industry with its proprietary regenerative reagent H_2S removal process called Sulfcat®. The first commercial installation with Blackspur has been in operation for nearly 2 years. It is a proven, regenerable H_2S removal technology that provides the lowest total cost of operations along with the most effective environmental reduction in SO_2 and associated GHG's, in today's energy market. The only waste product is low grade sulphur, which is relatively easy to dispose of.

It also means elimination of triazine, known for toxicity and improved efficiency in all operational aspects of H_2S sweetening systems. There is up to 80% operating cost reduction for customers and improves economic viability for sour natural gas projects. It is highly scalable due to a wide range of operating conditions. It facilitates power generation with sour gas and with biogas.

Sulfcat® Process Components

Absorption	▪ Sour gas is contacted with the Sulfcat® solution in the absorber ▪ H_2S is selectively removed and sweet gas exits the tower ▪ H_2S is converted to elemental sulfur
Regeneration	▪ The spent solution enters the oxidation vessel to regenerate the solution using air
Sulfur Separation	▪ Sulfur is settled from the solution either within the oxidation vessel or a dedicated settling tank ▪ A filter is used to provide high quality cake and recover the valuable Sulfcat® solution



Source: H2Sweet

The state-of-the-art process is unique in that it is a "replacement technology" for the traditional scavenger solutions. This regenerable chemical sweetening significantly reduces the costs of operations and eliminates the need to send liquid waste to disposal wells.

Blackspur's use of H2Sweet

In 2017, Blackspur's facility near Brooks, was faced with being shut-in after being advised that their third-party processor could no longer accept sour gas. Traditional sweetening processes were investigated and found to be highly uneconomic. Building a pipeline to alternative sour infrastructure would require additional capital and result in significantly higher operating costs.

The Sulfcat® system was commissioned in the spring of 2018 and has been continuously running without any unscheduled downtime and no off-spec gas production. The Sulfcat® system has reduced the operating costs associated with sweetening by approximately 80% and the facility was paid out in 18 months based on operating cost savings on a C$1.2mm capital cost. The fully automated controls allow for optimization and fine tuning of both operating costs and H2S removal efficiency. The treatment cost of the gas fell to C$0.4/mcf from C$1.40/mcf and CO2 was reduced by over 90% versus the use of triazine.

Sulfcat® Environmental Highlights

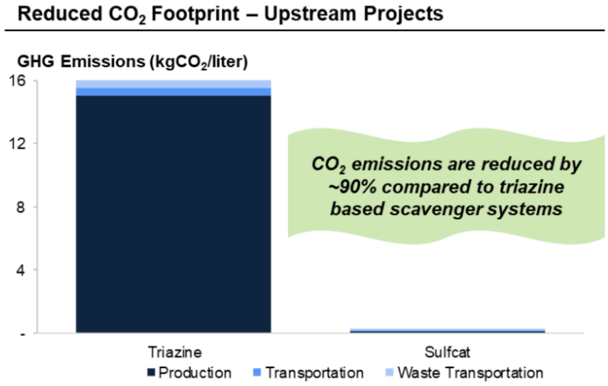
~90% reduction in CO_2 emissions [1]

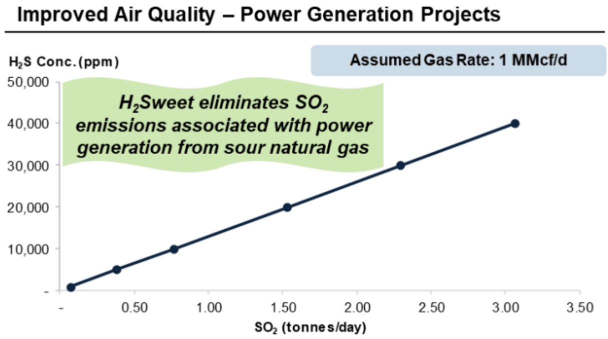
~90% reduction in volume of chemical consumed [1]

~75% reduction in volume of waste product [1]

Elimination of SO_2 emissions

Potential for emission reduction / carbon offset credits



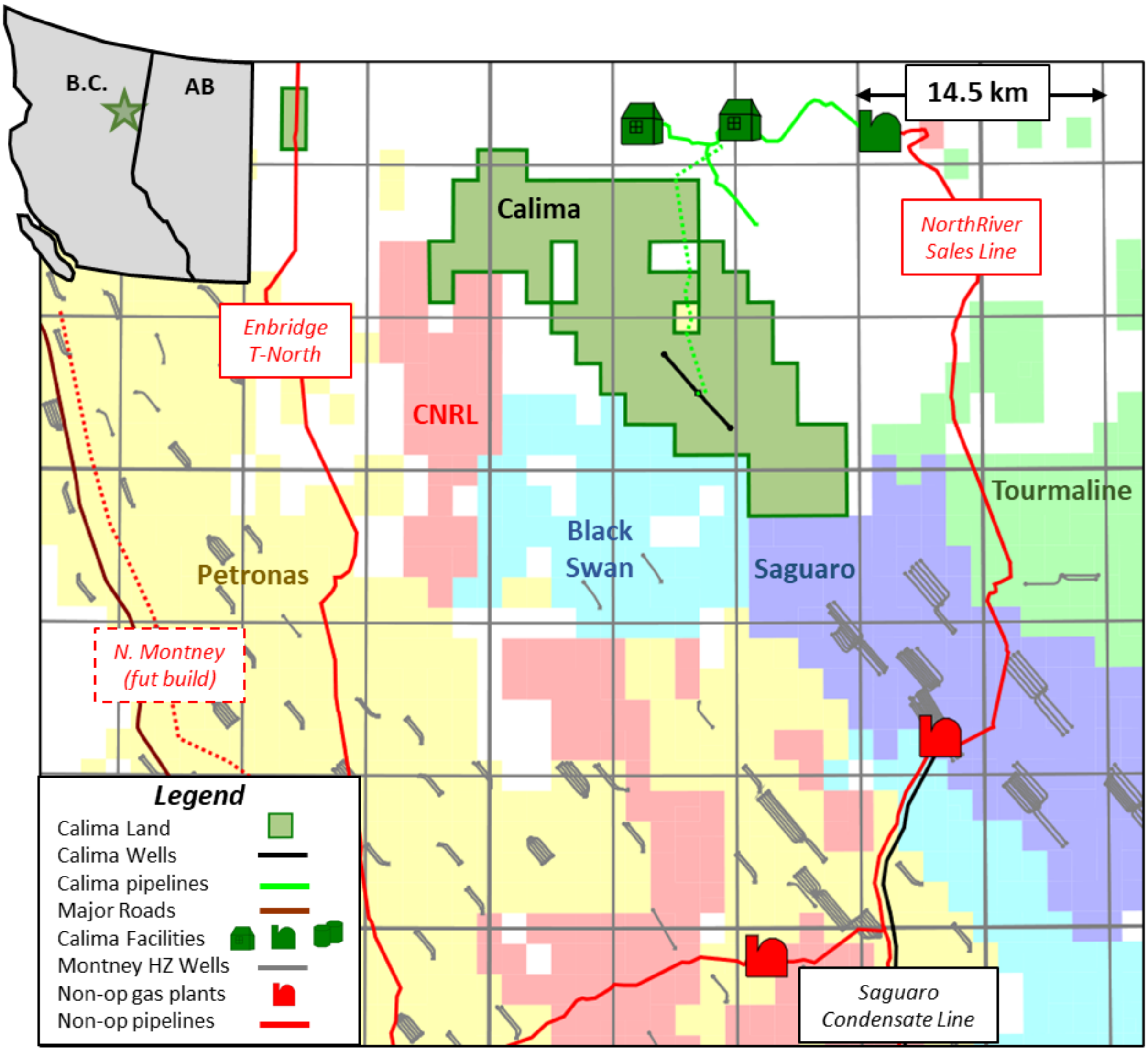


Source: H2Sweet

Reducing environmental impact is a strategic imperative for companies. H_2Sweet is the best alternative for the environment as the lowest carbon emissions alternative and it eliminates SO_2 emissions. It also reduces the volume of waste product and provides the potential for carbon offset credits.

Montney

Montney map



Source: Calima

Background
Calima was incorporated as an explorer focused on the Montney and the company succeeded in what it set out to prove. The exploration team identified an extension of the Montney play fairway into an area that many in the industry thought would be unproductive – a similar approach to the frontier exploration the management team employed successfully in Africa in the past. It did so using some proprietary geological analysis and advanced predictive analytics. The wells that it drilled proved the viability of the play, finding good quality reservoir, wet gas (i.e. good condensate yield) and demonstrated an attractive flow rate. The reservoir quality turned out to be better than expected.

The attraction of the Montney was that the formation is thicker than most other conventional plays in North America, allowing for multi-layer completions from a single well pad. Also, the productive reservoirs are generally siltstones with natural porosity rather than much tighter shale rock and they are well suited to fracture stimulation. Furthermore, the economics of the liquids rich window of the Montney are some of the best in North America helped by a low royalty structure and shallow drilling depths. Daily production in 2017 was already 4.6bcf/d plus 250kbbl/d of condensate with approximately C$5bn in investment into the play. Calima's closest peer, Saguaro has finding and development costs of <C$6/boe. Canadian drilling data is all open access, so it is very conducive to shared learnings and lowering costs.

The original aim of the company was to get to this stage and then look for a monetisation event. However, several factors in the market meant that this was not viable. Growth in Montney production, as well as mainline maintenance and expansions, caused gas take-away capacity to be overwhelmed, meaning large differentials to US gas prices and over the last few years US gas prices have also been depressed. Furthermore in 2020 there was the added impact of much weaker liquids pricing on the back of COVID.

The level of interest in the Montney has increased recently and we think the drivers are going to continue to spur further attention, especially as it is ideally positioned to supply West Coast LNG projects. In 2021, there has been a marked improvement in US gas prices, Canadian gas price differentials (actually trading at a premium at times) and crucially liquids pricing. Therefore, the economics of the Montney now look much better. Also, the outlook is promising with further oil and gas pipeline capacity coming and in particular the start-up of LNG Canada in a few years' time, that still requires additional gas to fill the plant. There has also been consolidation seen in the Canadian space, most notably the ARC Resource's takeover of Seven Generations to create the largest Montney producer. Also noteworthy is the expected sale of private company Saguaro to Tourmaline for an estimated C$350mm.

The acquisition of Blackspur has given Calima the ability to focus on near term growth and cash flow generation through its recently purchased assets. This gives Calima the luxury of time to wait for a further improvement in Montney market and to evaluate potential value creation opportunities for the assets given that it has 10 year leases secured on most of its acreage. Also, it now has much higher return and faster payback opportunities from its Blackspur acreage.

Valuation

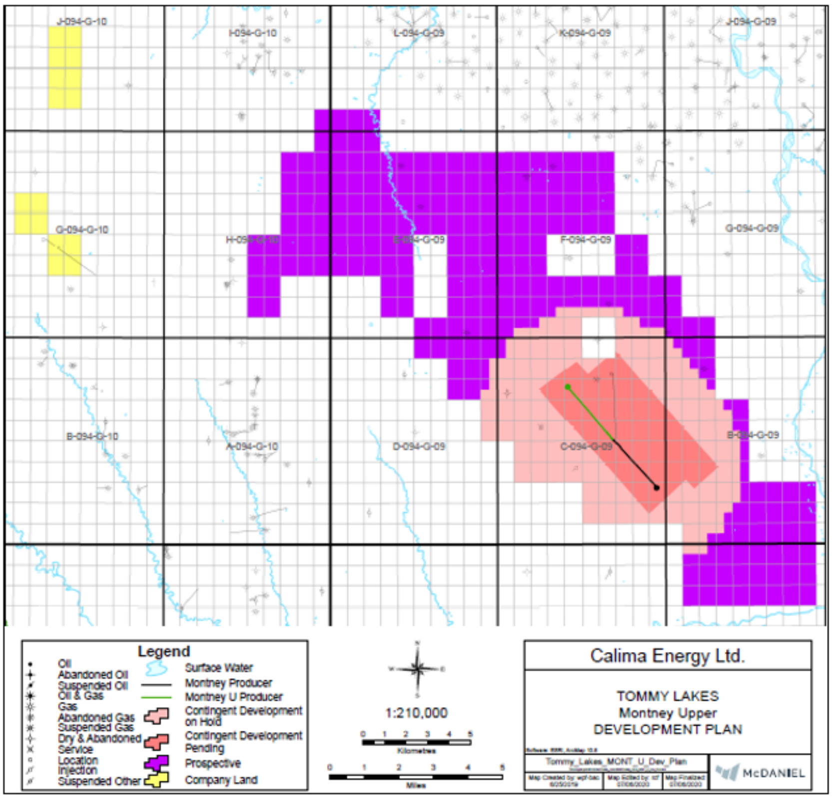
Overall, we see the range of the current value for the Montney assets between C$25mm and C$75mm. The floor price is based on where Calima was trading before the Blackspur deal was announced (although that is conservative as the Montney focused companies have performed strongly since).

Our bottom up valuation of the Montney assets implies a risked value for the 50mmcf/d development cast of C$55mm, however unrisked this is close to C$150mm. In total we carry ~C$75mm in risked value for the Montney including further contingent resource and prospective resource.

We estimate that acreage valuations in the Montney have been done at around C$1,500-2,000/acre (e.g. Conoco/Kelt and CNQ/PONY) when excluding the value of production / PDP reserves. Based on Calima's core acreage of 34k acres implies a valuation of C$51-68mm or on its total acreage position of ~60k acres implies C$89-118mm.

Calima's Montney Resource

Map of Calima Lands defining the areas of Prospective (purple) and Contingent Development on hold (light pink) and Contingent Development pending (dark pink) Resources.



Source: Calima

Calima Energy holds a 100% working interest in a land position of ~60k acres. This includes 34k acres (49 sections) held under a 10-year Continuation Lease (valid to 2029) awarded because of the 2019 drilling campaign and the balance held leases that expiring in 2021/2. All the contingent resource lies within leases that do not expire until 2029.

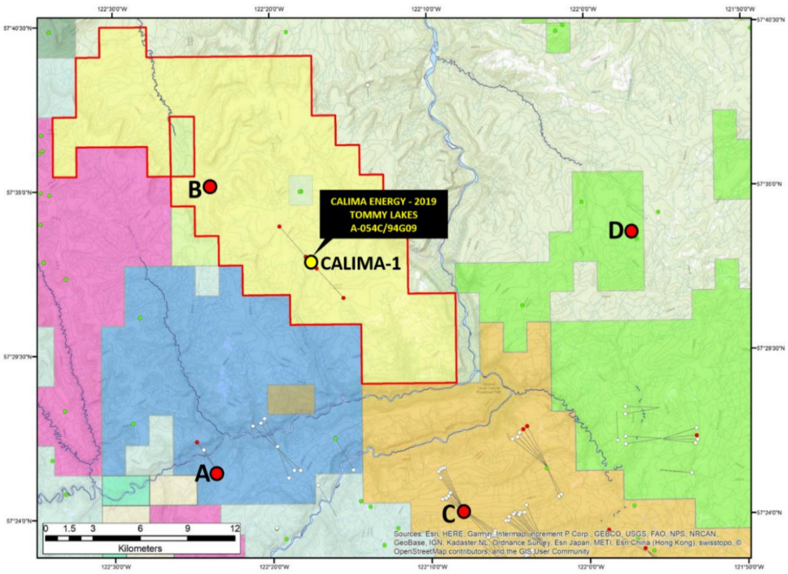
Exploration and appraisal drilling

Calima has drilled three wells to evaluate the potential of the Montney formation on its acreage. Pressure and flow test results from the Upper Middle Montney in Calima-2 and the Upper Montney in Calima-3, in addition to core analysis from Calima-1, indicate the presence of high productivity zones at the northern edge of the current Montney fairway. Regional mapping and the production history of analogue wells at Laprise and Birley Creek also point to Calima's wells becoming strong performers. While not tested, lower Montney intervals, based on core and log analysis from Calima-1, represent a potential resource that to date has been underdeveloped elsewhere in northeast BC.

Overall the Middle Montney was in line with expectations and analogous to Saguaro, whilst the Upper Montney is a bit more complicated as although the reservoir quality was better the reservoir is normally pressured.

3rd party analysis of results

Map of vertical wells referred to in table below



Reservoir parameters of Calima-1 well versus nearby wells

Compiled for Calima Energy (March 2019) by: NUTECH		LOCATION A	LOCATION B	CALIMA ENERGY CALIMA-1	LOCATION C	LOCATION D
UPPER TARGET (tested with Calima-3)	Porosity (%)	3.8	4.5	5.3	4.1	4.1
	Hydrocarbon Sat. (1-Sw) %	67.8	87.7	87.5	68.7	82.6
	Thickness (m)	48	49	46	38	35
	Clay (%)	18.6	16.6	14.3	18.2	16.1
	TOC (%)	1.48	2.13	1.7	1.36	2.0
MIDDLE TARGET (tested with Calima-2)	Porosity (%)	3.7	4.1	4.5	3.8	3.4
	Hydrocarbon Sat. (1-Sw) %	67.7	82.0	75.2	65.9	48.5
	Thickness (m)	73	70	73	65	64
	Clay (%)	23.7	23.3	20.6	20.8	18.8
	TOC (%)	1.05	1.33	1.3	0.92	0.93
LOWER TARGET (upside potential)	Porosity (%)	4.3	5.1	4.9	4.7	4.5
	Hydrocarbon Sat. (1-Sw) %	70.3	72.5	62.0	63.1	62.7
	Thickness (m)	146	132	136	158	136
	Clay (%)	30.0	27.4	27.0	30.2	28.4
	TOC (%)	0.87	0.87	1.1	0.65	0.59

Source: Calima, H&P estimates

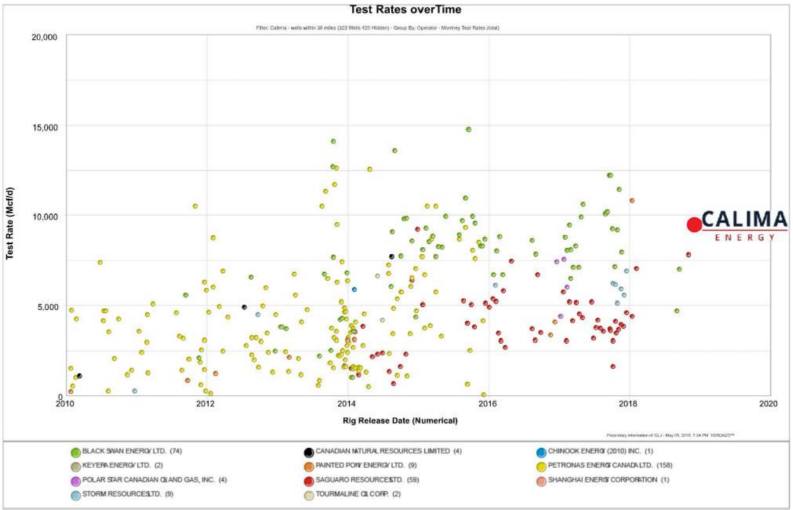
Following the acquisition of wireline log data in the Calima-1 vertical well, NUTECH Energy, a leader in reservoir intelligence, performed a comparison with nearby wells. Notably, the key reservoir parameters of porosity and hydrocarbon saturation are far superior to the average of those calculated in the offset wells.

Average porosities in Calima-1, for the Upper and Middle Montney targets, are 28% and 20% higher, respectively, than the average of the offset wells. Porosity is a measure of the available pore-space capable of holding hydrocarbons and water and thus has a direct influence on the volumes of hydrocarbons in-place.

Average hydrocarbon saturations in Calima-l, for both the Upper and Middle Montney targets, are 14% greater than the average of the offset wells. The hydrocarbon saturations calculated in the wireline analyses were confirmed by AGAT's core analyses. Hydrocarbon saturation defines the percentage of hydrocarbons taking up pore space within the reservoir rock and will have a direct bearing on the volumes of hydrocarbons in-place.

The well, identified as Location B in the table above, is located ~8km northwest of Calima-1 and only 5km from the bottom hole location of Calima-3. Well B was drilled vertically by a previous operator to target a conventional reservoir below the Montney. The results of the Well B analysis validate the northwards extension of the Montney reservoir quality encountered in the Calima wells. The Well B location could be a de-risked future well pad.

Well test rates over time by Montney operator



Source: Calima

Following the well testing, Calima commissioned an independent technical auditor, to review and benchmark the results. In a March 2019 report, GLJ stated *"...it is fair to say the Calima-2 well is likely to meet or exceed the performance of adjacent wells. This is true both in terms of overall production performance (such as gas production rate) and in terms of liquid yield."*

In comparison to regional Montney testing data, the report concluded that *"...from the D-021-C well (Calima-2), one can see that the total gas test rate from the Calima well compares favorably to other liquids-rich wells"*.

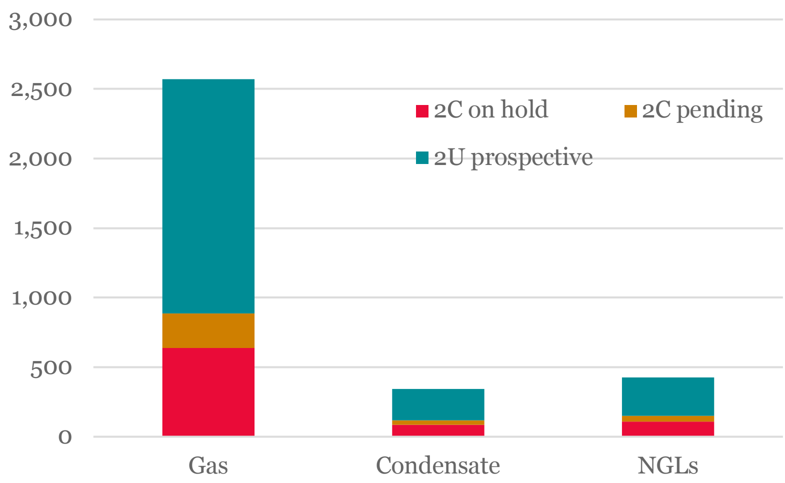
More recently, Canadian Discovery Ltd (CDL), a leading expert in the Western Canadian basin with extensive proprietary technologies and databases, completed a detailed study of the data collected from the three wells from Calima. The Calima wells confirmed the liquids rich Montney fairway extends further north than previously thought.

“Pressure and flow test results from the Upper Middle Montney in Calima-2 and the Upper Montney in Calima-3, in addition to core analysis from Calima-1, indicate the presence of high productivity Montney zones at the northern edge of the current Montney fairway. Regional mapping and the production history of analogue wells at Laprise and Birley Creek also point to Calima’s wells becoming strong performers. While not tested, lower Montney intervals, based on core and log analysis from Calima-1, represent a potential resource that to date has been under-developed elsewhere in northeast BC.”

Resource and development

In total Calima has found almost 200mmboe of 2C resource: 44mmbbl of liquids and 890bcf of gas. Calima now regards a significant portion its Montney acreage as being development ready, subject only to securing the necessary funding to construct a tie-in pipeline. Once it secures funding, then according to the reporting standards, these Development Pending resources could be classified as 2P reserves. In July 2020, Calima was able to upgrade 249bcf of gas and 12.4mmbbl of liquids (in total 330bcfe or 54mmboe) to Development Pending Contingent Resource. This means that this resource is development ready subject to securing the necessary funding to construct a tie-in pipeline. Once this takes place the resource can be upgraded to 2P reserves.

Calima's Montney gas and liquids resource by type (bcf equivalent)



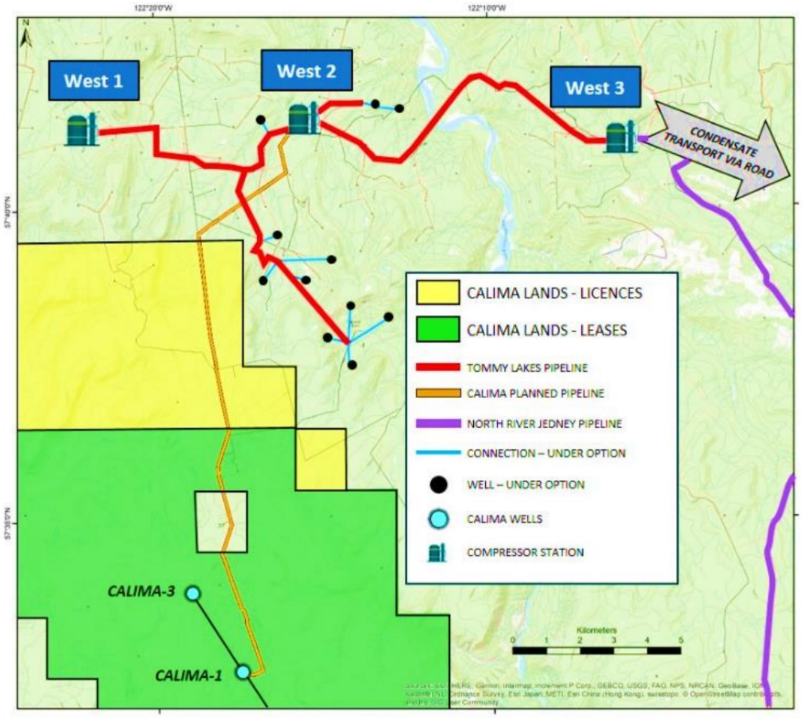
Source: Calima, H&P estimates

Approval to construct and operate a multi-well production facility has been granted by the BC Oil and Gas Commission, which includes a permit to construct a 19.5 km steel 8-inch service pipeline to connect the Calima well-pad with regional pipeline and processing infrastructure. Trialta Projects, the lead engineering contractor, costed the procurement and installation of the pipeline at ~C$17 million. The pipeline, which will run through the core of the Calima Lands, will connect existing and future Calima wells to the Tommy Lakes infrastructure with capacity to transfer up to 50 mmcf/d of wet gas and 1,500 bbl/d of wellhead condensate through to the North River Midstream sales line, providing access to the Canadian and US gas markets at AECO, Alliance and T-North/Station 2.

The facilities include tankage, electrical generation, metering and a control centre. The construction design is modular, allowing for the construction offsite. This ensures an efficient, cost-effective installation within the winter. While the initial approval is for the existing two Montney wells drilled at the beginning of 2019, it is envisaged that additional modules would be added to the pad site to accommodate a 20 well pad.

Gas and liquids produced from the wells will be separated and measured at the wellhead; the liquids will be re-injected back into the pipeline for transportation to the Tommy Lakes gathering system where it will be transferred into a North River Midstream sales line. Produced water will be removed at the well-pad to be recycled and stored for future completions.

Tommy Lakes Infrastructure Map



Source: Calima

The Tommy Lakes Infrastructure lies immediately 20km's north of the Calima Lands and offers the closest, most cost-effective tie-in to processing facilities and sales pipelines. Infrastructure includes gathering pipelines, compression facilities and associated facilities capable of transporting up to 50mmcf/d of gas and 1.5-2kbbl/d of well-head condensate. The Tommy Lakes field connects to a raw (wet) gas pipeline that leads directly to the NorthRiver Jedney processing plant which in turn provides immediate access to the major export routes. The Facilities provide Calima with pipeline access to regional, national and US markets via the major pipeline networks such as NGTL, Alliance and T-North. New pipeline investment and capacity growth will allow for gas to be directed towards the Shell/Petronas' LNG Canada Facility via the Canada Coastal Link pipeline.

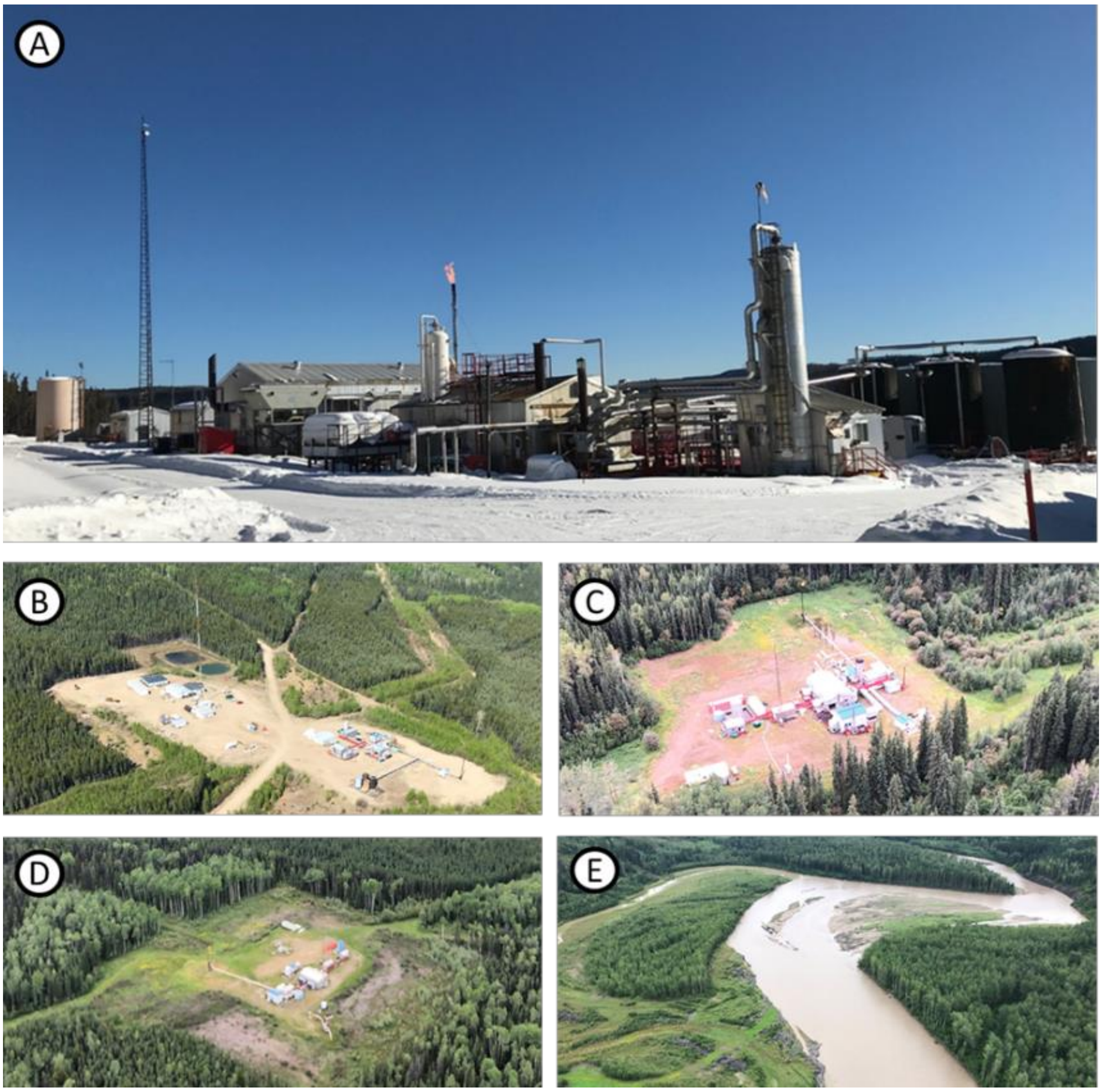
Calima acquired the facilities from Enerplus with the acquisition closing in April 2020. Third party due diligence confirmed that all pipelines and other assets are in good working order. The cost of the acquisition and shut-in was ~A$0.75mm. Holding costs are anticipated at A$0.5mm per annum. The Tommy Lake infrastructure continues to be maintained by Sproule and Associates with their local field operations staff. The estimated replacement value of the facilities is A$85 million. Calima booked A$1.9mm of restoration obligations in relation to the acquisition.

Concurrent with the acquisition of the Facilities, Calima has entered into an option agreement to acquire 11 gas production wells on or before 1 April 2022 in the Tommy Lakes field. These wells provide the Company with the option to use gas as fuel as part of the start-up sequence for the Facilities, if required.

The wet gas will then be further processed at the North River Midstream Jedney plant, where additional natural gas liquids (NGL's) recovered during processing will be removed and transported via pipeline to a liquid's hub adjacent to the Alaska Highway. The NGL's recovered during processing include additional condensate (C5+) plus lighter fractions such as Propane (C4) and Ethane (C3). The North River Jedney processing plant provides immediate access to the major export routes that service western Canada such as NGTL/AECO, Alliance and T-North/Station 2.

Calima continues discussions with NorthRiver Midstream to secure the ability to deliver volumes of up to 50 Mmcf/d into their Jedney processing plant. Based on current capacity Jedney can receive up to 25 Mmcf/d from the Calima Lands. Whilst the raw gas line to Jedney can handle well-head condensate, the Company plans to remove most of the condensate at the Tommy Lakes offloading station east of the Sikanni River (~22bbls/Mmcfd). Additional condensate and other natural gas liquids will then be recovered form subsequent processing at Jedney.

Tommy Lakes Field A. Tank storage, liquids handling facility and West 1 compressor, B. Field office, control room and camp facility, C. West 2 Compressor, D. West 1 Compressor, E. Location where the Tommy Lakes pipeline crosses underneath the Sikanni Chief River



Source: Calima

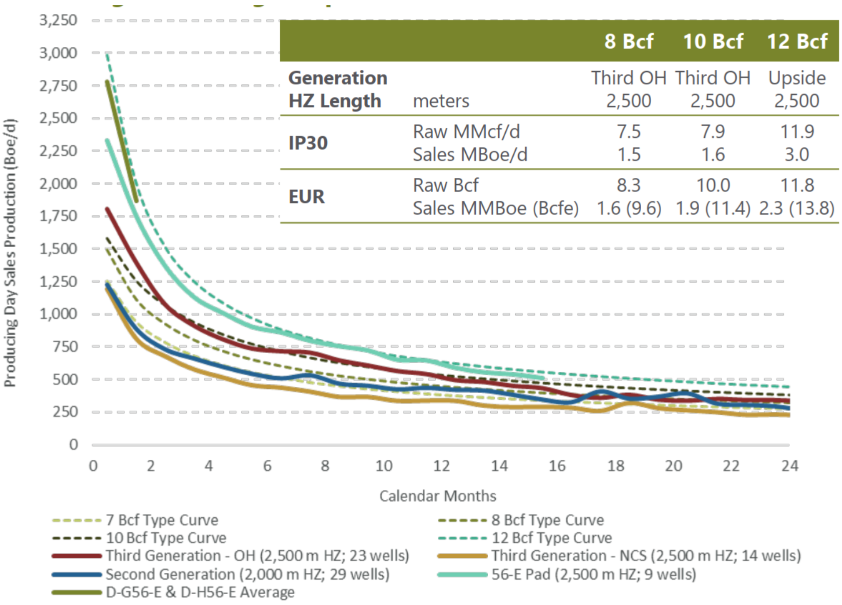
Development

We see various development scenarios. A simple case is producing from the existing couple of wells that have been drilled, however this will require a C$25mm pipeline and facilities spend to tie-in these wells. Whilst this is unlikely to generate a strong return, it will get the company to a producing stage and provide further data, which we believe will make it more attractive to potential suitors. The lead time to get to first gas is around 6 months but construction is only possible in the winter.

Calima's initial well costs were very high as it was a one-off programme but moving into factory development mode should take costs down to in line with peers. The drilling cost for the wells is currently estimated at C$5.3mm plus C$0.3m in facilities costs. Saguaro's well costs are currently around C$5mm to drill and complete. There is potential to reduce costs even further as Tourmaline for example can drill for <C$4mm but this is based on much larger scale.

Saguaro has also been demonstrating that its advanced well design has driven a material type curve improvement with 2 of its wells exceeding a 12bcf type curve versus its current 8bcf EUR curve. Saguaro's 2020 onstreams rank in the top 1% of wells drilled in BC and AB in 2020, for both IP30 (Boe/d) and IP90 (Boe/d).

The acquisition of the Tommy Lakes infrastructure allows Calima to manage and control where its gas goes.



		8 Bcf	10 Bcf	12 Bcf
Generation		Third OH	Third OH	Upside
HZ Length	meters	2,500	2,500	2,500
IP30	Raw MMcf/d	7.5	7.9	11.9
	Sales MBoe/d	1.5	1.6	3.0
EUR	Raw Bcf	8.3	10.0	11.8
	Sales MMBoe (Bcfe)	1.6 (9.6)	1.9 (11.4)	2.3 (13.8)

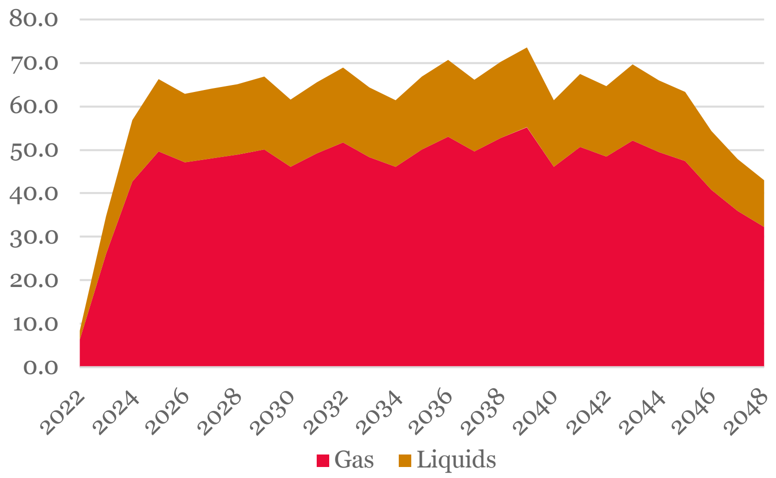
Given the fairly remote location of the acreage, there is a substantial cost to get the gas to access market pricing (i.e. AECO or Station 2 hubs). The transportation cost to get the gas from the Tommy Lakes facility to the Jedney processing plant is around C$0.75/mcf with a further C$0.75/mcf processing cost and then ~$0.2/mcf from here to access either AECO or Station 2 pricing. Overall the transportation and processing cost is expected to be ~C$1.5/mcf.

100mmcf/d development

A full scale development of around 1tcf of gas and ~60mmbbl of liquids would see plateau production of around 100mmcf/d. The total capital cost will be ~C$1bn.

Base case development and valuation

Production profile (mmcfe/d)

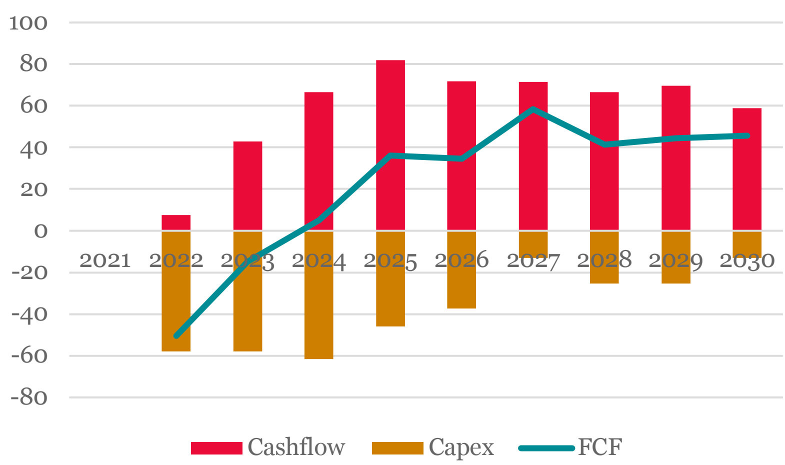


Source: Calima, H&P estimates

The base case development is to grow production to 50mmcf/d of gas plus 3kbbl/d of liquids, within the constraints of the existing infrastructure and maintain it at that level for potentially a few decades. Under this scenario 125mmboe (560bcf of gas, 16mmbbl of condensate and 16mmbbl of NGLs) are produced. The capital expenditure required over the life is C$615mm, which works out at less than C$5/boe development cost. Operating costs average C$7.1/boe or C$1.2/mcf.

The initial capex in the first couple of years ahead of getting to positive free cashflow is around C$100mm with a small amount of free cash flow coming in years 3. We estimate that ~50% of the revenue comes from gas, a third from condensate and the rest from NGLs.

Cashflow and capex profile (C$mm)



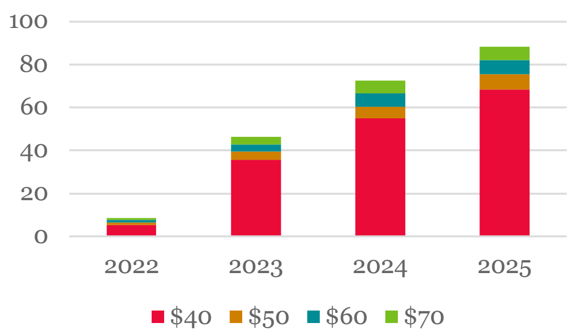
Source: Calima, H&P estimates

Montney NPV/boe (C$/boe) valuation at various Brent/AECO prices (US$/boe)

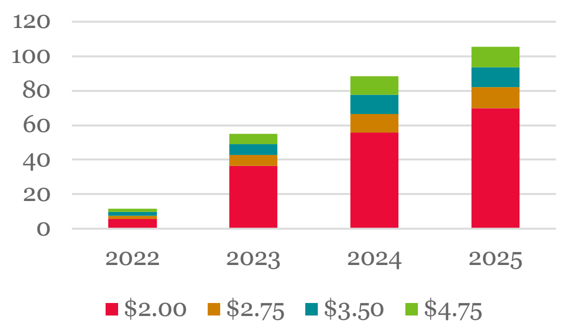
Source: Calima, H&P estimates

Our overall NPV is C$2/boe and we estimate an IRR of 25%. Based on this production profile from the core 34k acres implies a C$10,000 per acre valuation. The charts below show the sensitivity of cashflows to changes in oil price and gas price.

Sensitivity of cashflow (C$mm) to Brent (US$/bbl)



Sensitivity of cashflow (C$mm) to AECO (US$/mcf)



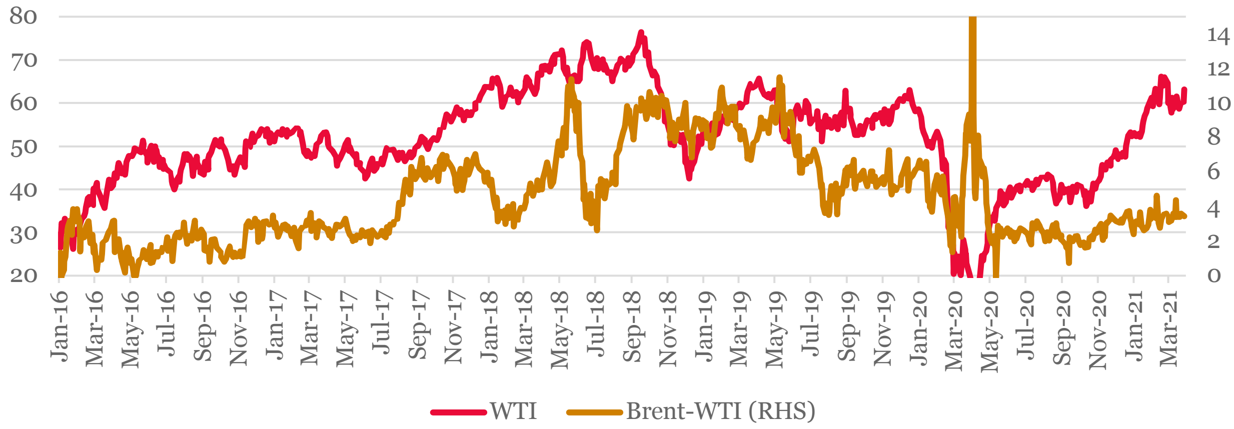
Source: H&P estimates

Canadian hydrocarbon pricing

Canadian oil, condensate and gas pricing has significantly diverged from US and global market pricing over time because of factors such as infrastructure constraints and demand for the various products. Therefore, it is important to look at the key Canadian differentials to US market pricing and the drivers behind these. The main differentials are:

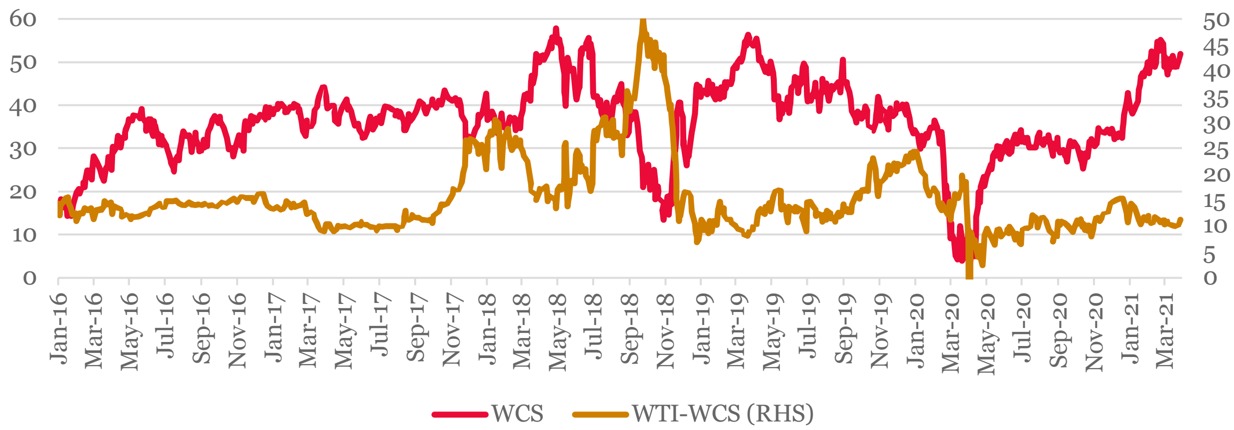
1. **WTI discount to Brent.** For international companies, Brent is the main crude indicator that the market focuses on. Our main crude price forecast is of the Brent price. Although WTI is a higher quality crude than Brent, it trades on a discount given the relative oversupply of WTI following the US shale boom of the last decade and the cost of getting it on to the market. Our long term Brent price forecast is US$60/bbl and we estimate that WTI will trade on a $3/bbl discount. YTD the discount has been $3.3/bbl and we think the overall US vs. international crude dynamics will stay similar.

WTI price and Brent-WTI spread (US$/bbl) since 2016



Source: H&P estimates, Bloomberg

WCS price and WTI-WCS spread (US$/bbl) since 2016



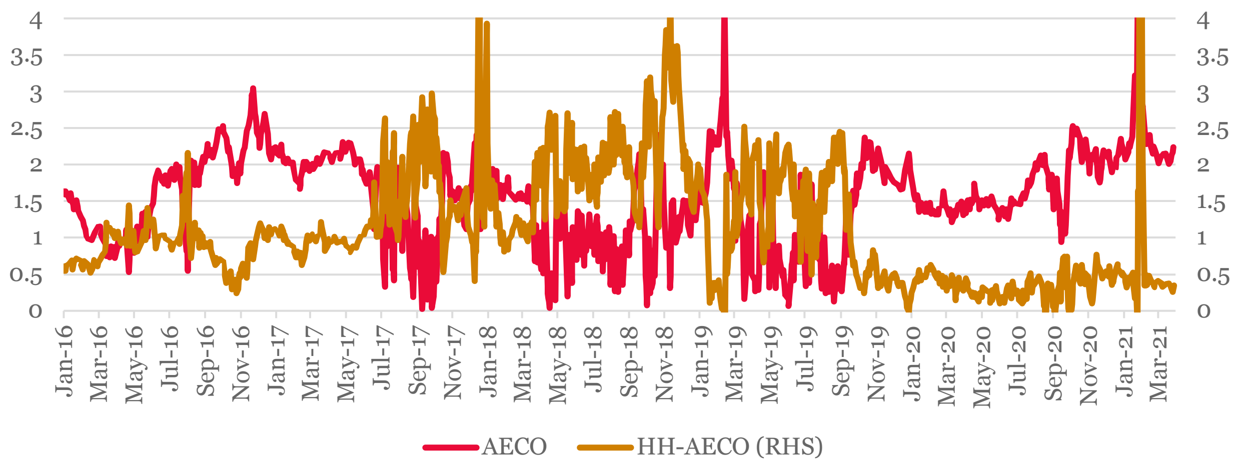
Source: H&P estimates, Bloomberg

2. **WCS discount to WTI.** This is most important to Calima's current production which is oil weighted. West Canadian Select is the main marker crude grade in Canada. Calima's crude production is geared into this differential. The discount is a result of the cost to access the market. The differential has blown out to >US$50/bbl but has more recently narrowed in to around US$10/bbl and the futures curve is pricing in US$10/bbl over the next few years and we forecast US$12/bbl. We expect this differential to remain narrow as a result of a combination of new pipeline capacity coming on line, underlying production declines in Canadian conventional production and increasing demand for Canadian heavy oil from the US Gulf Coast given declining supply of heavier crudes in the US and globally (e.g. Mexico/Venezuela). The chart below shows the WCS price in Canadian dollar terms, with the price in April averaging C$65/bbl versus our long dated forecast of C$56/bbl.

WCS price (C$/bbl) since 2016

Source: H&P estimates, Bloomberg

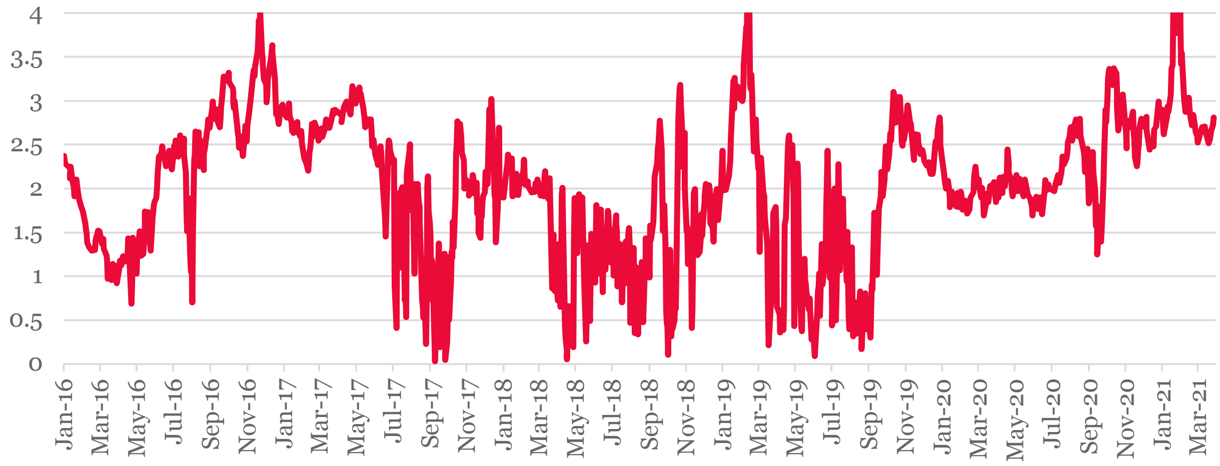
AECO price and HH-AECO spread (US$/mcf)



Source: H&P estimates, Bloomberg

3. **AECO discount to Henry Hub.** This has a smaller impact on Calima's cashflow given the smaller amount of production but is important for the Montney. AECO is the main pricing point in Canada and it experienced a similar situation to WCS. Over the last few years AECO has traded at a large discount to HH pricing as production overwhelmed the pipeline capacity as well as the policy put in place by pipeline operator TC Energy stopping delivery to interruptible customers during maintenance. However, as new pipelines have come on stream and TC Energy allowing additional service flexibility and production has declined, the differential actually flipped to a premium at times this year. We forecast a Henry Hub price of US$3/mcf and an AECO spread to Henry Hub of US$0.5/mcf. Below the AECO price in Canadian dollars is shown.

AECO price (C$/mcf)



Source: H&P estimates, Bloomberg

4. **Condensate premium to WTI.** This is important to Calima's development of the Montney as condensate accounts for a large portion of the economics given the much higher $/boe value of condensate versus gas. For example, at current pricing with 13% condensate production and 75% gas, condensate would account for 32% of revenue and gas 53%.

5. **NGL pricing.** This is a minor impact for both current production and future production. Generally, NGL pricing is on a sharp discount (~50% to WTI). Around 13% of the Montney production is expected to be NGLs.

Company History

2017

- June: Azonto Petroleum reported it had received firm commitments of A$2.25mm in equity funding at A$0.045/sh to acquire Calima Energy with a substantial acreage position in the Montney oil and gas formation in Canada.

- August: Completion of the acquisition of Calima and commencement of trading under new name Calima Energy.

- September: Calima licenced 60sqkm of 3D seismic data over the core Calima lands, acquired a well database of 60 wells within 3km and initiated well planning studies with a view to drilling in 2018. Acquistion of an additional 13k acres of drilling rights.

- October: Independent geologist's report by McDaniel confirmed the prospectivity and comparability to its neighbour Saguaro.

- December: Acquistion of an additional 2.7k acres of drilling rights.

2018

- February: Secured authorisation to construct, maintain and operate an oil and gas road ahead of drilling. Appointed CWL Energy to provide regional project management services

- March: As part of the operating agreement with CWL, Calima appointed a Country Manager: Mike Dobovich and Operations Manager: Aaron Bauer. Calima earned a 20% working interest in the Montney after reaching a C$5mm spend milestone. McDaniel pulished an independent resource estimate of 2.1tcf of gas and 114mmbbl of liquids. Raised A$3.5mm at $0.055/sh.

- May: Bid to acquire JV partners TSV Montney and TMK Montney to consolidate its position and take control of 100% of the assets through the issuance of 425mm shares, increasing the share count by 77%. Award of a 56% stake in Block 2813B in Namibia's Orange Basin.

- July: Ramdar Resource Management appointed to manage Calima's drilling and completion operations and Trialta Projects appointed to provide design, engineering and construction management for facilities and pipeline infrastructure.

- August: Completion of acquisition of TSV and TMK Montney. Mark Freemen joined Calima. Following a review of >500 multi-stage drilling completions in the Montney within 75km of its first drilling location, Calima optimised completion techniques for its planned drilling of 2,500m horizontal sections with 85-90 stimulations. A$25mm placement at A$0.054/sh. Tribeca, which as the cornerstone investor, agreed to arrange project financing of up to $40mm.

- September: Shell sanctioned the 14mmtpa LNG Canada project, with pipelines to feed the terminal located adjacent to Calima's acreage.

2019

- January: Arrival of rig at the Calima drilling pad and Calima-1 vertical well spudded days later. Recovery of 230m of core, 90% of the entire

257m thick Montney interval and intersected the top of the formation within 4m of pre-drill prognosis. Core analysis confirmed presence of condensate. Wireline logging confirmed porosities and hydrocarbon saturations comparable with adjacent producing wells. Calima-2 horizontal well spudded and completed by month end and Calima-3 spudded.

- February: Calima-3 well completed with a 2,561m horizontal section. Drilling matched best-in-class performance of other operators in the area.

- March: Resevoir stimulation commenced on Calima-2 and 3 in 92 stages using sliding sleeve completions. Calima-2 and 3 both took up the full proppant load of 45t/stage across almost every stage. Calima-2 flowed at 1,640boe/d: 9mmcf/d of gas and 143bbl/d of liquids during the final stages of clean-up. Maximum flow rate was 10.2mmcf/d. Comparisons with nearby wells suggest Calima-2 should match or exceed liquids rates from adjacent areas. Calima-3 operations had to be ended early due to the arrival of unseasonal early spring melt. Calima-3 was at the early stage of unloading at rates of >2.5mmcf/d, consistent with the early stage rates on Calima-2. Drilling allowed the conversion of 35k acres of drilling rights to 10-year production licences.

- April: Oil saturation meansurs from core of upto 59% in the Upper Montney and 64% in the Middle Montney were signficantly higher than in adjacent areas, confirming both zones lie in the liquids rich fairway. Calima-1 wireline log analysis of the Upper Montney showed porosities that are 28% higher than average peer group wells and 20% highr in the Middle Montney. Gas compositions suggest that 70% of the liquids are high value condensate relative to 50% expected pre-drill.

- May: Calima responded to an ASX Appendix 5B Query questioning whether it will have sufficient cash to continue funding its operations. Calima noted it was looking at debt or equity funding or the potential to joint venture with regional players. Sale of Namibian exploration assets to Tullow Oil for US$2mm/A$2.9mm plus success bonus up to US$10mm.

- July/August: A$12.7mm capital raise through a placement and rights issue at A$0.018/sh. McDaniel revised Gross prospective resource (2U) to 497mmboe and added contingent resource of 196mmboe – previously there was just 476mmboe of prospective resource. It estimated an EUR per well of 8.4bcf (vs. 5.6-6.8bcf previously).

- September: Company undertook cost saving measures including a 50% reduction in headcount. Mark Freeman appointed Chief Financial Officer.

- October: Appointment of Mr Brett Lawrence as a non-executive director. Completion of sale of Namibian assets and receipt of A$2.9mm in proceeds. A 10-year Continuation Lease over 33,643 acres awarded over Calima Lands.

- November: BC Oil and Gas Commission provided approval to construct and operate a multi-well production facility at Calima's Montney pad location.

- December: Permit granted to construct pipeline to connect the Calima well-pad with regional pipeline and processing infrastructure.

2020

- January: Jon Taylor resigned from the Board of the Company. He was instrumental in the growth of Calima Energy from its beginnings and in the sale of the Namibian acreage to Tullow Oil.

- February: Calima secured the acquisition of Tommy Lakes infrastructure, which will provide the Company with cost-efficient access to North River Midstream pipeline and Jedney processing facility.

- March: Management changes announced: Strategic movement of management to Canada. Mr Micheal Dobovich, assumed the role of President; Alan Stein has transitioned to a Non-Executive role; Jon Taylor resigned as a director and Mark Freeman, Chief Financial Officer, has taken on additional Company Secretary responsibilities. Effective 1 April 2020 all Directors agreed to convert their director and executive fees to shares.

- July: Resource Upgrade – Driven by Tommy Lakes Acquisition

- September: Calima engaged Canadian Discovery to complete an in depth analysis of the most significant Montney core retrieved to-date.

- October: Downhole Pressure Data Confirms Montney Productivity.

- November: Mr. Neil Hackett resigned from the Board of the Company to concentrate on other commitments.

- December: Canadian Discovery Limited released their preliminary findings from the study of Calima's 3 wells confirming the presence of high productivity zones.

2021

- February: Calima announced the merger with Blackspur and was suspended from trading.

- May: Completion of merger with Blackspur and Calima resumes trading. Calima announces strong well performance from initial 3 well Sunburst drilling programme.

Blackspur history

2012

- Private equity backed, founded through the recapitalisation of Eiger Energy Ltd.
- Average production of ~80 boe/d

2013

- Drilled 3 (3 net) wells and delivered C$1.3 million in operating cash flow
- Exit production of ~250 boe/d and ~20 net sections of land

2014

- Completed the C$14.3 million Brooks acquisition adding 250 boe/d and raising C$32.0 million in an equity financing
- Exit production of ~1,200boe/d and ~165 net sections of land

2015

- Completed a C$7.1 million acquisition adding 180 boe/d and raising C$12.5 million in an equity financing at $0.50/share
- Exit production of ~1,500 boe/d and ~162 net sections of land

2016

- Completed the C$8.5 million additional Brooks acquisition adding 250 boe/d funded through the sale of Taber
- Completed non-core asset divestiture at Taber (170 bbl/d) for gross proceeds of C$6.7 million
- Exit production of ~1,300 boe/d and ~170 net sections of land

2017

- Completed a C$28.5 million equity financing at C$0.45/share
  Acquired remaining 50% WI at Thorsby
- Exit production of ~4,300 boe/d and ~264 net sections of land

2018

- Continued to delineate the Brooks and Thorsby regions, drilling 14 (14 net) wells
- Exit production of ~4,300 boe/d and ~283 net sections of land

2019

- Reduced rate of development to achieve living within cash flow operations
- Exit production of ~3,500 boe/d and ~240 net sections of land

2020

- Blackspur drilled 2 (2 net) wells in 2020
- 2020 exit production of >2,600 boe/d

Management Profiles

In March 2020, Calima shifted the management team to Canada following the growth, development and evolution of the Company from explorer towards being an operating company. Alan Stein stepped down as Managing Director and Micheal Dobovich, previously a senior executive with Statoil Canada, assumed the role of President. Effective 1 March 2020 all Calima's Directors agreed to convert their director and executive fees to shares.

Board of Directors & Key Management

Name	Profile
Glenn Whiddon, Chairman, May 2015	• Over 30 years of experience in equity capital markets, banking and corporate advisory, with a specific focus on the natural resources sector • Founded Lagral - a company focused on investment management activities in mining, energy and property, and serves as its Principal • Previously, served as the Executive Chairman of Auroch Minerals and Rialto Energy / Azonto Petroleum (now Calima), and as the Executive Chairman, CEO and President of Grove Energy • Prior to that, co-founded Pinnacle Associates – a company that took direct investments in the Russian natural resource sector • Also, served as the Representative and In-Country Manager at Bank of New York between 1991 - 1994 • Holds a Bachelors in Economics and Accounting from Macquarie University, Australia
Jordan Kevol, Managing Director and CEO, May 2012	• Over 16 years of public and private Canadian junior E&P experience • Co-founded Blackspur Oil and served as its President and CEO since 2012 • Currently, also serves as the Director of Source Rock Royalties • Previously, served as the President of Petro Uno Resources, Vice President of Renegade Petroleum, Geologist at Penn West Exploration, and Manager of Geology and Drilling Ops at Reece Energy Exploration • Holds a B.Sc. in Geology from the University of Regina, Canada
Braydin Brosseau, Chief Financial Officer and VP Finance - Blackspur, Sep 2014	• Was Vice President, Finance and CFO at Blackspur Oil Corp. and H2Sweet Inc. • Prior to that, served as a Controller in West Valley Energy Corp from 2012 to 2014 and Aston Hill Financial Inc from 2010 to 2012 • Started his career at PwC in 2006 • Holds a Bachelors in Commerce (distinction) from University of Saskatchewan, Canada and is a qualified Chartered Professional Accountant

Name	Profile
Mark Freeman, Chief Financial Officer and Corporate Secretary - Calima, June 2018	• Over 20 years of experience in corporate finance and the natural resources industry • Experience in strategic planning, business development, mergers and acquisitions, North American gas commercialisation, and project development general management • Served several successful public resource companies and has been providing strategic advice to TSV Montney since 2015 • Holds a Bachelor of Commerce from University of Western Australia, and a Graduate Diploma in Applied Finance from the Securities Institute of Australia
Micheal Dobovich, Vice President Corporate Sustainability March 2020	• Extensive experience in Canadian E&P and has worked in multiple basins in North America for over 20 years with a background in land, regulatory, indigenous relations and commercial activities • Previously, served as a Calima's Country Manager and has been a key part of the Management team since 2017 • Led the operationalisation of Calima during the 2019 drilling campaign and most recently, the acquisition of the Tommy Lakes Facilities • Prior to that, served as the Head of Safety and Sustainability and as a Manager of Land and Regulatory Affairs at Statoil (now Equinor), Canada • Also, served as Senior Land Coordinator at Pioneer Land and Environmental and at Compton Petroleum, Surface Land Coordinator at City of Medicine Hat and as a Land Agent at Standard Land Company • Holds an MBA from Royal Roads University, Canada and a Diploma in Land Acquisition and Management from Olds College, Canada
Dorn Cassidy, Vice President Operations, August 2014	• Currently, serves as the President of H2Sweet Inc and was Vice President, Operations at Blackspur Oil • Prior to that, served as a Senior Production Engineer at Capio Exploration from 2010 to 2014 and Hunt Oil company from 2008 to 2010, Operations Engineer at Sherritt International from 2006 to 2008 and Production Engineer at Enerplus from 2004 to 2006 • Holds a Bachelors in Applied Science, Petroleum Engineering from University of Regina, Canada
Alan Stein, Non-Executive Director, July 2017	• Over 25 years of experience in the international oil and gas industry • Currently, serves as the Non-Executive Chairman of Hanno Resources and Sea Captaur. • He is a Partner at Havoc Partner - a natural resources investment company focused primarily on the oil and gas sector • Co-founded geoscience consultancy IKODA, based in London and Perth, and was the founding Managing Director of Fusion Oil & Gas plc and Ophir Energy plc • Holds a PhD in Geology from University of London and B.Sc. in Geology from University of Aberdeen
Brett Lawrence, Non-Executive Director, October 2019	• Over 15 years of diverse experience in the oil and gas industry • Currently, serves as the Managing Director of Tamaska Oil and Gas since 2018, Non-Executive Director of Acacia Coal, and is a Partner at Xponova • Previously, served as the Managing Director of Macro Energy • Prior to that, worked with Apache Energy for over eight years, performing roles in drilling engineering, reservoir engineering, project development and commercial management • Holds a Masters' of Petroleum Engineering, a Bachelor of Engineering in Mining and Bachelor of Commerce in Finance from Curtin University, Western Australia
Lonny Tetley, Non-Executive Director	• Extensive experience in corporate governance, equity financings and M&A transaction work

Name	Profile
	• Co-founded Cetarus and currently serves as its Director. Also, works in the corporate finance and securities group of Burnet, Duckworth & Palmer LLP • Currently, serves as the Director and/or Corporate Secretary of several issuers and is also a member of a Private Funds Independent Review Committee for Deans Knight Capital Management • Holds a Bachelor of Law and a Bachelor of Commerce in Finance from the University of Calgary, Canada
	•

Source: Company Website, Report, and LinkedIn

Investment Risks

Other than the usual risks facing oil and gas companies (e.g. commodity prices, COVID-19, security, geopolitical, geological, ESG and health & safety risks), the main specific risks that we see facing Calima are:

- **Well performance:** One of the main risks to the growth potential of Calima is that the wells planned on the newly acquired Blackspur acreage underperform expectations. However, this is mitigated by there being a number of wells that have been drilled in both core areas and production from those wells in aggregate exceeding the type curves put out by the reserves consultants.

- **Cost inflation:** There is a risk that with higher oil and gas prices and also rising commodity prices (e.g. steel), that cost inflation comes through, especially with regards to higher capital costs. We think that this risk is mitigated by the strong economics at current oil prices and if oil prices do retreat from here, this will likely eliminate any upward pressure on costs.

- **Abandonment liabilities:** Blackspur had total asset retirement obligations of C$16.9mm on an undiscounted basis, which relates to around 125 inactive wells. Although this is a substantial portion of the total acquisition cost, relative to peers it has a leading Liability Management Ratio (LMR) rating of ~4.63. Also, the cost of abandonment is expected to be incurred over a long period of time (more than a decade), meaning that the annual liability is expected to be around C$1mm or less.

- **National Bank of Canada Debt Financing:** There is a risk the debt facility and the terms may not be extended beyond periodic review dates. However, given the strong balance sheet and expected cash flow generation we see from Calima; even in the unlikely scenario that the facility is not extended, we think that the credit metrics mean that it should be possible to refinance elsewhere.

- **Requirements to Raise Additional Funding:** For Calima to develop its Montney position it will most likely need to find a funding solution as it will be tough to fund a development off its own balance sheet. However, we do not see an equity raise to fund this as likely or imminent given the ample time Calima has remaining on its core licences and the likelihood that a farm-out will take place ahead of any large development.

- **Canadian price realisations:** There have been various instances in the past where Canadian oil and gas prices have traded at very wide discounts to US prices and this has impacted Blackspur's revenues in the past. However, we think that there is a lower risk of this being repeated in the future. Pipeline apportionment is managed through multiple delivery points and nominations.

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