28 March 2022

Brooks and Thorsby Reserves Update 2022

Highlights

- ✓ Blackspur Reserves as at 31 December 2021 - audited by InSite Petroleum Consultants Ltd:
  - **3P reserves 24.4 million boe**
  - **2P Reserves 20.4 million boe**
  - **1P Reserves 15.6 million boe**
  - **PDP Reserves 5.1 million boe**
- ✓ Blackspur drilled 12 wells in 2021 of which 11 were proven undeveloped locations (PUD) which moved locations from the 1P category to cash flow generating Proven Developed Producing (PDP) wells.
- ✓ The focused asset bases of Brooks and Thorsby coupled with high graded infill drilling and prudent production management allowed Blackspur to maintain reserves steady after production of 1.1 million boe since 31 Dec 2020.
- ✓ Updated Reserve Report and Development Plan incorporates:
  - 60 development wells as 54 PUD's and 6 probable
  - Development plan is designed for proved and probable well locations to be drilled within a 5-year period
  - Costs for abandonment, decommissioning, reclamation, and salvage of facilities, and inactive assets for all of the Company's existing and proposed wells
  - Preparation in accordance with the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS)
- ✓ Blackspur estimates approximately 228net wells will develop the entire reserve position on its existing lands > 5 years out.
  - 90% of undeveloped Brooks and Thorsby acreage has no reserves booked currently, representing significant upside to the existing report

Calima Energy Limited (**ASX:CE1 / OTCQB: RLTOF**) (Calima or Company) is pleased to announce InSite Petroleum Consultants Ltd ("InSite") has completed its reserves evaluation as at 31 December 2021 for Calima's wholly owned subsidiary Blackspur Oil Corp. ("Blackspur").

	Reserves as at 31 December 2021 (working interest after royalties)														
	31-Dec-21			Production		Additions		Revisions		Acquisition		31-Dec-20		
	Oil/NGL (mbbl)	Gas (mmcf)	Boe (mboe)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Oil/NGL (mbbl)	Gas (mmcf)	Boe (mboe)
PDP	3,279	11,136	5,135	-618	-1,793	1,200	2,742	-212	-92	2,909	10,280	0	0	0
1P	10,122	32,654	**15,564**	-618	-1,793	760	1,033	-224	-248	10,204	33,663	0	0	0
Probable	2,993	10,984	4,824	-	-	152	156	-454	-1,085	3,295	11,913	0	0	0
2P	13,115	43,638	**20,388**	-618	-1,793	912	1,189	-678	-1,333	13,499	45,576	0	0	0
Possible	2,521	9,067	4,032	-	-	112	201	2409	8,866	0	0	-	-	-
3P	15,635	52,705	**24,420**	-618	-1,793	1,024	1,390	1,731	7,533	13,499	45,576	-	-	-

Table 1: Reserve Statement

Development Plan

The development plan in the 31 December 2021 Reserve Report consists of 60 (gross) wells to be drilled over 5 years. The schedule and breakdown in each reserve category is summarised in the table below.

Period	Rig Count	Development Well Count			
		Proved (PUD)	Probable	Possible	Total
Year 1	2	13	0	0	**13**
Year 2	2	14	5	0	**19**
Year 3	2	11	0	0	**11**
Year 4	2	12	0	0	**12**
Year 5	2	4	1	0	**5**
Total	10	54	6	0	**60**

Table 2: Rig and gross well count for each year

As at 31 December 2021, the 2022 development program includes 13 wells to be drilled including, 3 Thorsby Sparky wells, 4 Brooks Sunburst wells, and 6 Brooks Glauconite wells (2 are now drilled as part of the Pisces campaign). Blackspur's working interest in each well dictates the reserves the Company can book during the well's productive life. On a net well count for the proved reserve category, Blackspur has a ~92% interest in the proved undeveloped wells in the 31 December 2021 development plan for 2022.

As at 31 December 2021, Blackspur held the rights to ~110,500 net acres within the Brooks and Thorsby areas. The Company operates 67.6 net wells developing approximately 8,700 net acres of this position.

The year-end reserve development schedule encompass development of a modest portion of the total acreage position that Blackspur holds. Based on the existing leasehold position, including the acreage associated with the existing producing wells, Blackspur estimates a total of approximately 228 (net) wells will develop the entire reserve position. The total 31 December 2021 development schedule corresponds to 60 future wells, or 24% of the wells necessary to develop the entire acreage position. Approximately 90% of the undeveloped Brooks and Thorsby acreage does not have reserves booked, representing significant upside.

InSite assessed all future locations they determined to be commercial. The key assumptions used by InSite to generate the Reserve Report were:

- The majority of the reserve estimates were prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.
- The oil price used for all reserves analysis in this report is stated in the table at the end of this release. The reserves are disclosed net to the point of sale (reference point) and are reported net of lease fuel.
- Blackspur is the operator for materially all its producing wells and all the future drills.
- Operating costs for developed producing wells are based on actual costs incurred through YE2021. Operating costs for future wells and years are based on the same data and estimated following a review of operating statements, operating budgets, as well as review of public records where available. Cross checks were conducted between the revenue statements and land data to ensure they agreed. Fixed and variable costs have been assigned to Blackspur's active assets with remaining reserves. Operating costs associated with

inactive assets as well as producing wells with no reserves assigned have been entered as separate entities at the property level.

- In conducting InSite's reserve analysis, proved, probable and possible reserve volumes were determined by volumetric, material balance, and production decline curve methods. The volumetric reserves were determined by reviewing all well logs, core, and geological data. Recovery factors were assigned after analyzing the performance of similar wells in the area. Historical well production was reviewed to determine reserves calculated by production decline curve analysis. The order of preference in choosing the methodology to be used was primarily production decline curve analysis or material balance where sufficient data was available for such analysis with volumetrics being used where there was a lack of historical data.

- 100% of the proved producing reserves were calculated based on decline analysis, oil-cut analysis and other performance/volumetric related prediction methods, compared to 33.1% (33% net) of the total proved reserves and 30.9% (30.9% net) of the proved plus probable reserves, and 31.0% (31% net) of proved plus probable plus possible reserves which used these methods. Volumetrics/simulation/analogy/type curve analyses were used to calculate the remaining percentages of reserves in each category.

- The EUR assignments are largely influenced by the production performance of existing producing wells and their associated volumetric recovery. In the case of undeveloped drilling locations, reserve assignments and production profiles are based on analogy to the offsetting producers in the nearby vicinity and/or other analogous pools.

- The probable reserves contained in the report consist of two general types:
    - Performance-related (i.e. Proved plus Probable Developed) reserves represent the best estimate overall. Proved reserves are a more conservative estimate of the recovery from wells where Possible reserves represent a more optimistic and lower probability estimate.
    - Proved plus probable reserves can also include enhanced recovery reserves which are only partially recognized under proved reserves. The "wedge" or difference between the Proved Developed and Proved plus Probable Developed cases represents 29.9% (29.5% net) of the Company's Probable reserves. The "wedge" between Proved plus Probable Developed and Proved plus Probable plus Possible Developed cases represents 33.6% (32.4% net) of the Company's Possible reserves.

- Future horizontal step-out wells represent 65.9% (65.6% net) of the Company's probable reserves.

- Future vertical step-out wells represent 4.7% (4.9% net) for the Company's probable reserves.

- The oil and gas reserve calculations and income projections upon which this report is based were determined in accordance with generally accepted evaluation practices and evaluation process was consistent with prior years.

- Proposed future well locations are allocated a reserve category based on proximity to existing wells and production.

- Probable reserves were assigned such that there is a 50% probability that the assigned reserves could be recovered, or more on an aggregated basis.

- Proved plus Probable plus Possible reserves were assigned such that there is a 10% probability that the assigned reserves could be recovered, or more on an aggregated basis.

- The production and revenue forecasts contained in the 31 December 2021 evaluation include abandonment and reclamation costs for each of the Company's existing and proposed wells that were assigned reserves in this report. These costs were determined using the Alberta Energy Regulator's Directive 011 as a base. The costs associated with abandonment, decommissioning, reclamation, and salvage of facilities, as well as inactive assets, have been entered as separately.

- The five-year development plan used for this reserve report is detailed in Table 2 above and assumes a multi rig program to develop a total of 60 gross well locations. The development plan assumes 2-6 wells per standard development unit and approximately 128 - 160 acre spacing.

- Anticipated drilling, completion & tie-in well costs range from C$1.0 to C$3.4 million depending on whether it's a Sunburst, Glauconitic or Sparky well.

- The development plan assumes an initial estimate of 6-14 days respectively to drill new wells.

- Average royalties payable on future well locations that were allocated reserves in this report is ~15% over the life of the wells. The land type and related royalties are either Crown or Freehold and the average royalty for the PDP forecast for 2022 is 18.2%.

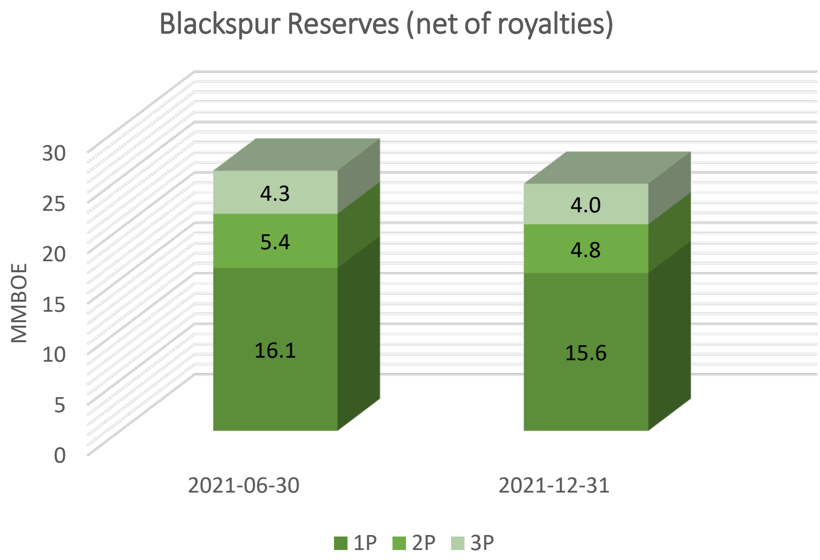
Each year, for the purposes of estimating undeveloped reserves, a development schedule is generated which must be appropriate and reasonable for the Company to execute on. This development plan is prepared in consultation with InSite and takes into consideration market conditions and the Company's operational capacity, including financing and historical drilling activity. The plan must also conform to the various ASX and SPE-PRMS requirements, the key points of which are:

- the development plan is executed over a 5-year period from the effective date.

- proved well locations must be drilled within 5 years of the date they were first certified as a reserve in previous reports.

- The InSite evaluation has been prepared for the Company in accordance with reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook and have been classified in accordance with the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS) and reported in the most specific resource class in which the prospective resource can be classified under 2018 SPE-PRMS. The reserves presented in the InSite report are based on forecast prices and costs. The price forecast used for the reference price of oil based on Cushing, Edmonton and Western Canadian Select benchmarks, as well as the netback prices for natural gas for the major purchasers. All oil prices used in the evaluation have been adjusted from the reference price for quality and transportation; gas prices have been adjusted for heating value. Please note that the effects of any oil or gas hedging activities by the Company have not been included in this report. The reserves are disclosed net to the reference point.

- In the context of belonging to a larger portfolio of properties and coupled with the principal of aggregation of reserves, the total portfolio reserves estimate carries a higher degree of confidence than the estimates for the individual properties.



Graph 1: Reserve Summary

Brooks

Brooks asset overview	**31 December 2021**
Land position and production	
Core land position (net acres)	**>40,000**
Core formation targets	**Sunburst, Glauconitic**
Average working interest of the play (%)	**90%**
Number of wells drilled to date (net)	**>60**
Identified drilling locations (Net)	**130**
February 2022 average production (boe/d)	**~2,400**
Reserves (mmboe)[(1)]	
Proved reserves	**8**
Probable reserves	**2**
Total proved plus probable reserves	**10**
Possible reserves	**1.7**
Total proved plus probable plus possible	**11.7**

Calima has an established core position of land (~63 net sections or ~40,500 net acres) and significant infrastructure that creates a foundation for growth and expansion, and importantly with year-round access. The Brooks asset averaged net daily production of 2,400 boe/d in February 2022.

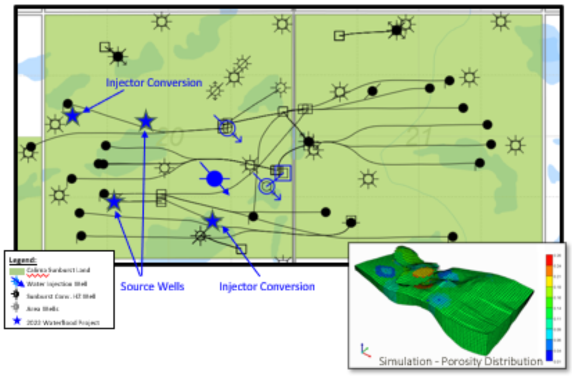
Blackspur + Calima have drilled >60 wells to date in this area and production comes from the Sunburst and Glauconitic Formations. Blackspur's existing Brooks infrastructure can process up to 8,200 bbl/d oil providing significant upside with limited infrastructure spend. The Brooks reservoirs have a low CO_2 content at 2, and our multi-well pad drilling reduces environmental footprint. The Sunburst Formation can be developed at low well cost of ~ C$1 million, delivering attractive rates of return and most importantly, short paybacks of ~4-6 months at US$70 WTI and standard type curves.

Calima Energy Ltd ACN 117 227 086
Suite 4, 246-250 Railway Parade, West Leederville WA 6007: +61 8 6500 3270
Fax: + 61 8 6500 3275 Email: info@calimaenergy.com www.calimaenergy.com

Future growth from the Brooks assets will come from the 130 net locations that have already been identified. These locations include ~34 booked (29.75 net) PUDs and 2 (2 net) probable locations. Only 23% of the identified locations have been booked for the purposes of InSite's Reserve Report. The Q1 2021 drilling program along with the upcoming H2 2022 program will be focussed on Sunburst and Glauconitic drilling. At current oil prices the Company is excited to continue drilling Glauconitic Formation horizontal locations. These Glauconitic wells can be very impactful to corporate production levels and reserve bookings. Additional reserves are also expected to be realised through implementation of enhanced oil recovery projects and specifically the full water-flood development of the Countess J2J Sunburst pool. The figure below in the Glauconite section shows a full field development in all formations.

J2J Waterflood

In January 2020, Blackspur initiated a waterflood in the Countess J2J Pool which is expected to show results in the near term. Insite has recognized 1P and 2P waterflood reserves. Waterflood operations require upfront capital and usually take time before field performance improves and the benefits are realized. When operational, these types of assets provide a stable, low decline production base generating strong cash flows.



The Countess Sunburst J2J Pool at Brooks was discovered in 2003 and initially developed using vertical wells. Horizontal drilling was introduced in the pool in 2014 which improved production rates and primary recoveries with strategically placed horizontal well legs throughout the reservoir.

A pilot waterflood and full battery buildout was completed in Q1 2020. Based on the initial results of the pilot, waterflood expansion was planned in 2022 with the goal of field wide waterflood development in 2023.

The Company has been pleased to note that the initial stage of the Countess J2J waterflood pilot has begun to show positive response in the producing wells and Insite has recognized 1P and 2P waterflood reserves. Increased inflow in existing producing horizontal wells indicates that the waterflood is working, and this initial waterflood response is in line with reservoir modelling, and waterflood simulation performed prior to implementation of the pilot waterflood.

The next stage for the waterflood includes converting two existing vertical wells into water injectors and converting an existing vertical well into a water source well, increasing the quantum and areal extent of water being injected in the Pool.

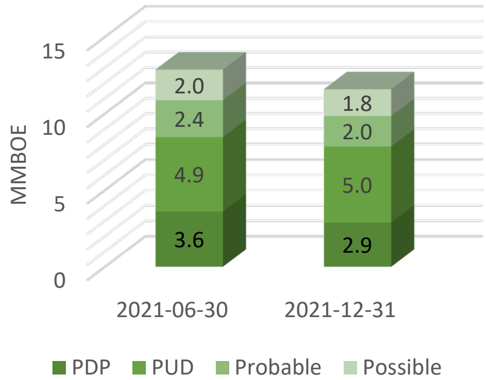
This is expected to increase the waterflood response in the Pool, resulting in increased reserves, shallower declines, and ultimately an increase in oil production.

Ultimate primary recovery factor for the Pool before any waterflood implementation is estimated at 14% of the oil in place, and the current recovery factor to date from the existing wells is estimated at 8%. Analogous Sunburst Formation pools under secondary recovery (waterflood) in the area, have achieved recovery factors of 25% or higher. Every 1% increase in recovery factor of the estimated 15mmbbl of oil in place in the J2J Pool, results in another 150mbbl of incremental recoverable reserves for the Company. Approximately 2% of the potential increase in recoverable reserves in the Countless J2J Pool have been included in the Reserve Report.

There is no change to the fundamentals of the undeveloped wells and InSite has made no material changes to their assumptions on future undeveloped well production performance. The InSite reports incorporates:

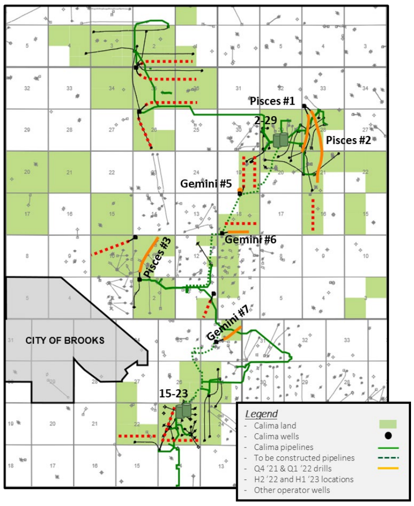
- In 2021 9 wells were drilled with 7 focusing on the Sunburst open hole (non-fractured) horizontal play type and 2 Glauconitic fractured horizontal wells.
- In 2022 four open hole Sunburst wells are planned in the reserve report.
- 34 PUDs (29.75 net) and 2 probable 100% locations
- 8 PUD to PDP conversions in 2021
- Reserves of: 1P - 8 mmboe, 2P - 10 mmboe, 3P – 11.7 mmboe

Graph 2: Brooks Reserves (net of royalties)



Pipeline Infrastructure at Brooks

Progress on the previously announced pipeline infrastructure (the "Pipeline") at Brooks is ahead of expectations and is nearly complete and trending to come in under budget. The Pipeline connects the Company's 2-29 oil battery in the northern portion of the field, to the recently drilled wells (**Gemini #5, #6, #7** and **Pisces #3**) in the southern portion of the field and most importantly, will provide egress for planned production growth in the pipeline corridor located in the heart of the Brooks properties. Exceptional construction efficiencies have been achieved through detailed project management by our engineering team, construction crews and field staff.

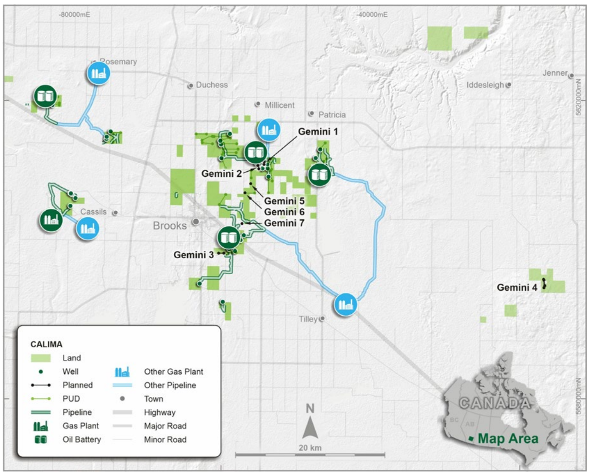


Gemini #5, #6 and #7 and Pisces #3 have all been completed and are now tied into the pipeline and producing.

The final section of the pipeline which connects existing producing wells in an area that currently has fluid volumes trucked to 02-29 battery, will be connected, and flowing into the battery by early April 2022. The Pipeline will significantly reduce operating costs, and will add several significant ESG benefits, including the elimination of flaring of new wells during initial production testing. Most importantly, it will eliminate trucked volumes of emulsion from existing, newly drilled, and future wells that are or will be connected to the 2-29 battery via the new Pipeline. Reducing trucking improves the Company's safety and spill prevention profile and ESG score.

Calima Energy Ltd ACN 117 227 086
Suite 4, 246-250 Railway Parade, West Leederville WA 6007: +61 8 6500 3270
Fax: + 61 8 6500 3275 Email: info@calimaenergy.com www.calimaenergy.com

Sunburst formation



The Sunburst Formation does not require hydraulic fracture stimulation and can be developed at low cost (C$1M-$1.4MM per well depending on the number of horizontal laterals and tie-in requirements) delivering attractive rates of return.

The Brooks reservoirs contain a low CO_2 content at ~2%, and the Company's multi-well pad drilling reduces the environmental footprint. The Brooks area contains significant infrastructure that creates a foundation for growth and expansion with year-round access. Blackspur's existing infrastructure across the entire Brooks area can process up to 8,200 bbl/d oil.

In 2021, the Company drilled seven (7 net) Sunburst wells in the Brooks area, four of which were drilled subsequent to the Blackspur Acquisition with Calima (Gemini #1-#4). Gemini #5-#7 Sunburst Formation wells in the Brooks area were drilled in January 2022 and are connected into the Company's 2-29 oil battery via the new pipeline described above.

On 28 January 2022, the Company entered into a definitive agreement with a strategic infrastructure and midstream company for up to C$5.0 million in capital to construct a pipeline connecting the Company's 02-29 battery in the northern portion of its Brooks, Alberta asset base to its wells, lands, and gathering system in the southern portion of the Brooks asset base.

Typical Sunburst drilling and production timeframes

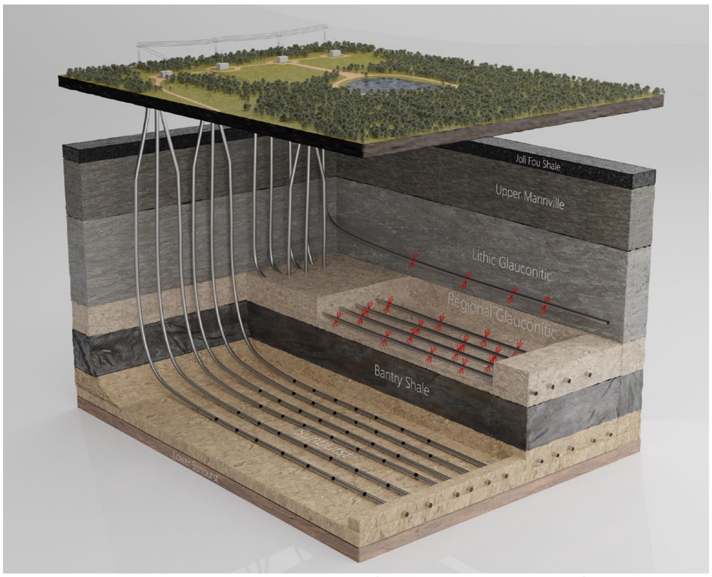
Drill Time	Completion	Tie-in	Clean-up*	IP30	IP90 type curve
7-10 days	2-3 days	5-20 days	5-10 days	30 days post clean-up	90 days post Clean-up*

* Clean-up is the period that water and drilling fluids are recovered from the completion and at after which time commercial hydrocarbons begin to flow from the reservoir.

Glauconitic Formation

The Glauconitic Formation is a shallower (younger) formation than Calima's core Sunburst conventional play and requires hydraulic fracture stimulation. The combination of the shallow target depth and short tie-in, results in an all-in cost for each well of C$2-$3M, depending on horizontal length of the wellbore.

The Company has three new Glauconitic wells (Pisces #1-#3) from its recent program and all 3 are completed, tied in, and producing. These Glauconitic wells are expected to be impactful to corporate production levels and future reserve bookings.



Typical Glauconitic drilling and production timeframes

Drill Time	8-12 days
Completion	15-30 days
Tie-in	5-20 days
Clean-up*	30-45 days
IP30	30 days post clean-up
IP90 type curve	90 days post Clean-up*

* Clean-up is the period that water and drilling fluids are recovered from the completion and at after which time commercial hydrocarbons begin to flow from the reservoir.

Thorsby

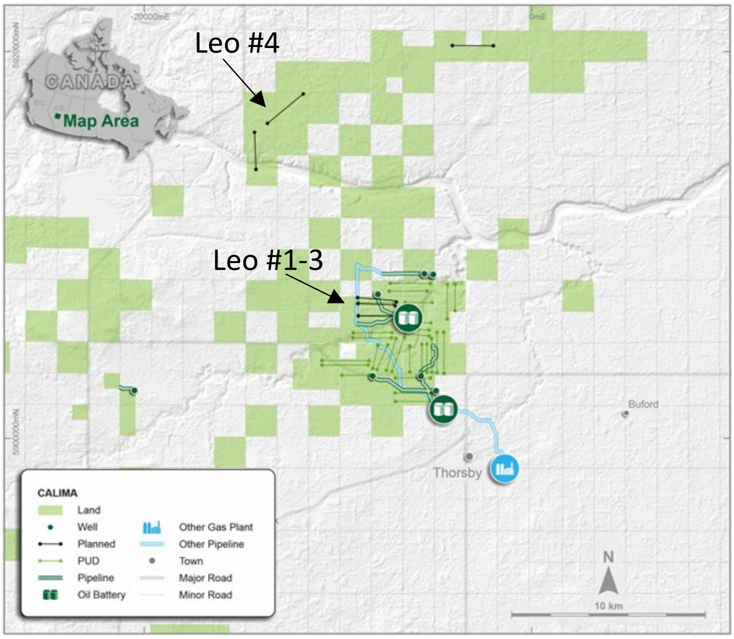
Thorsby asset overview	31 December 2021
Land position and production	
Core land position (net acres)	**>62,000**
Core formation targets	**Sparky, Nisku**
Average working interest (%)	**100 & 50%**
Number of wells drilled to date (net)	**15**
Identified drilling locations (Net)(1)	**98**
February 2022 average production (boe/d)	**~1,825**
Reserves (mmboe)(2)	
Proved reserves	**7.6**
Probable reserves	**2.8**
Total proved plus probable reserves	**10.4**
Possible reserves	**2.3**
Total proved plus probable plus possible	**12.7**

(1) Consists of 86 Sparky formation net drilling locations and 12 Nisku formation net drilling locations.
(2) Refer to Advisories and Guidance for additional information regarding the Company's reserves.

Sparky Formation

Thorsby has a large well inventory with 86 Sparky Formation and 12 Nisku Formation wells identified, including 20 PUD and 4 probable Sparky locations. The Company's existing Sparky Formation wells are characterised by a low decline rate of ~15% (net of new wells). Additionally, upside exists in 66 net sections of Duvernay Formation lands that were included in the Blackspur Acquisition.

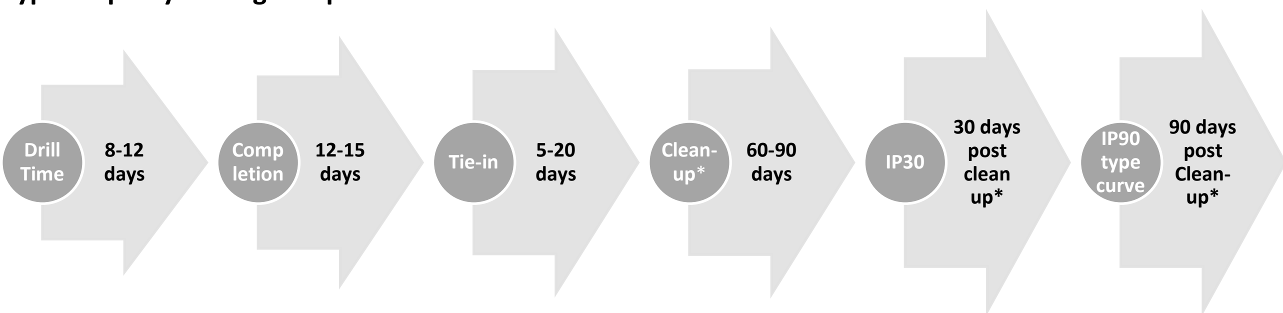
The Company's Thorsby position provides a consolidated land base that can be efficiently developed through a network of multi-well pads, all of which have year-round access. The contiguous land base also contributes to lower operating costs through greater logistical efficiencies. Blackspur's facilities currently have oil processing capacity of up to 4,000 bbl/d oil.



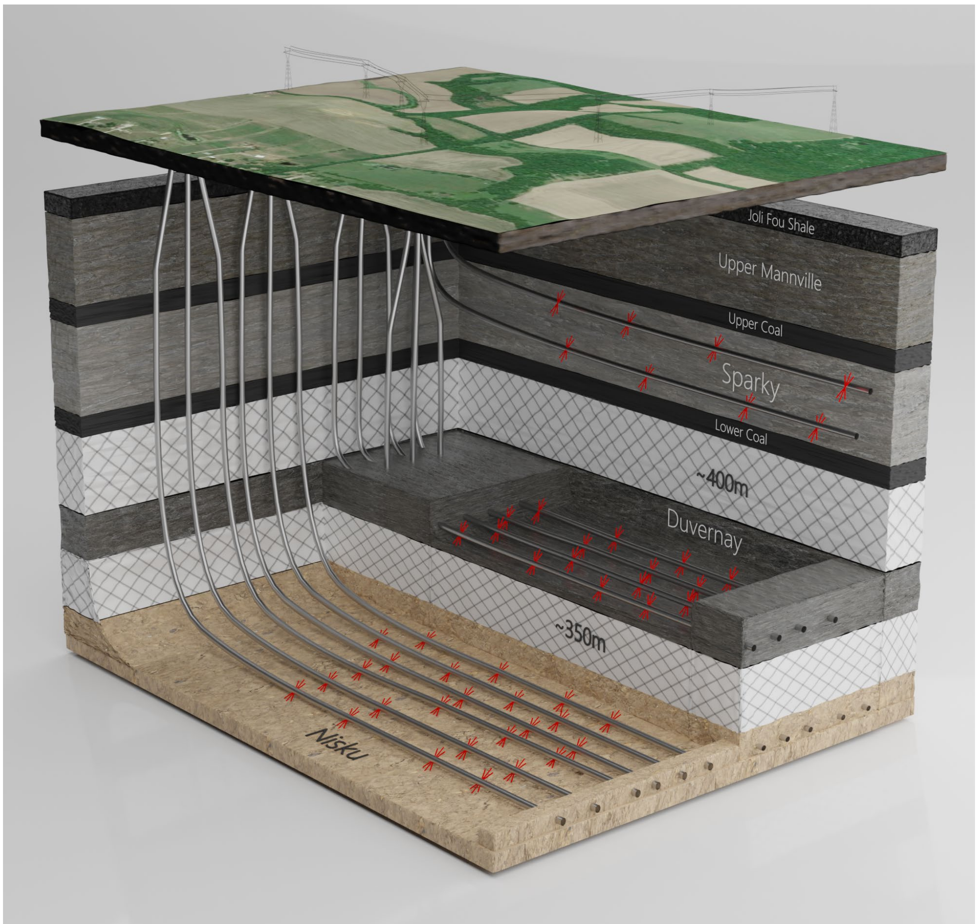
In 2021, Blackspur brought on stream three (net) Sparky wells in the Thorsby area (Leo #1-#3). All three wells are classified as development wells, as they were drilled into existing Sparky Formation oil pools, which were delineated by both existing Sparky wells and 3D seismic.

One step-out well (Leo #4) (0.5 net) is drilled in the prospective North Thorsby area and is planned for completion and tie-in in late Q2 or early Q3 2022.

Typical Sparky drilling and production timeframes



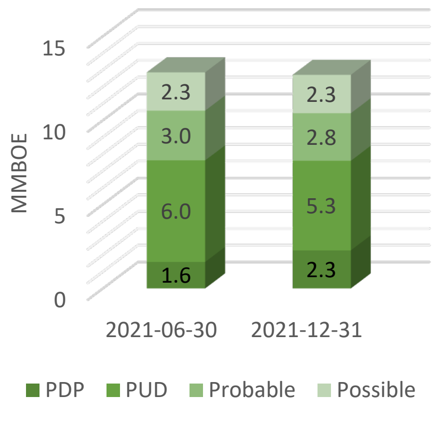
* Clean-up is the period that water and drilling fluids are recovered from the completion and at after which time commercial hydrocarbons begin to flow from the reservoir.



Full Field Thorsby Development

Blackspur continues to successfully optimise the drilling and completion techniques and InSite's development utilises longer horizontal wells with higher intensity fractures compared to the early-stage wells. This reduces gross well locations while the future undeveloped well production performance per well is improved. There was minimal year over year changes to the proven undeveloped reserves.

The Company plans to drill 3 development wells in Thorsby in 2022. Each are being drilled into the existing Sparky Formation oil pool, which was delineated by both existing Sparky wells and 3D seismic. The well length and frac intensity will be similar to the 2021 Leo drilling campaign.



- 3P production profile over a prolific reserve lifecycle
- 20 PUD's and 4 probable 100% locations
- Reserves of: 1P - 7.6 mmboe, 2P - 10.4 mmboe, 3P - 12.7 mmboe

Whilst the Thorsby area has the potential for Duvernay and Nisku, these intervals have not been incorporated into the Reserve Report.

3P Reserves

A proved, probable and possible (3P) reserve evaluation category was evaluated for all wells and locations booked at 31 December 2021 totalling 24.4 million boe's. 3P EURs are determined using volumetric calculation as well as production performance / type curve reserve estimates where applicable. This resulted in a significant possible reserve addition of 4.0 million boe, net of royalties. 3P reserves were split as follows: Brooks 3P reserves of 11.7 million boe and Thorsby 3P reserves of 12.7 million boe.This release has been approved by the Board.

For further information visit www.calimaenergy.com or contact:

Jordan Kevol	Glenn Whiddon	Mark Freeman
CEO and President	Chairman	Finance Director
E: jkevol@blackspuroil.com	E: glenn@lagral.com	E: mfreeman@calimaenergy.com
T:+ 1-403-460-0031	T:+ 61 410 612 920	T: + 61 412 692 146

Forward Looking Statements

This release may contain forward-looking statements. These statements relate to the Company's expectations, beliefs, intentions or strategies regarding the future. These statements can be identified by the use of words like "anticipate", "believe", "intend", "estimate", "expect", "may", "plan", "project", "will", "should", "seek" and similar words or expressions containing same. These forward-looking statements reflect the Company's views and assumptions with respect to future events as of the date of this release and are subject to a variety of unpredictable risks, uncertainties, and other unknowns. Actual and future results and trends could differ materially from those set forth in such statements due to various factors, many of which are beyond our ability to control or predict. These include, but are not limited to, risks or uncertainties associated with the discovery and development of oil and natural gas reserves, cash flows and liquidity, business and financial strategy, budget, projections and operating results, oil and natural gas prices, amount, nature and timing of capital expenditures, including future development costs, availability and terms of capital and general economic and business conditions. Given these uncertainties, no one should place undue reliance on any forward-looking statements attributable to Calima, or any of its affiliates or persons acting on its behalf. Although every effort has been made to ensure this release sets forth a fair and accurate view, we do not undertake any obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Qualified petroleum reserves and resources evaluator statement

The petroleum reserves and resources information in this announcement in relation to Blackspur Oil Corp is based on, and fairly represents, information and supporting documentation in a report compiled by InSite Petroleum Consultants Ltd. (InSite) for the December 31, 2021 Reserves Report. InSite is a leading independent Canadian petroleum consulting firm registered with the Association of Professional Engineers and Geoscientists of Alberta. These reserves were subsequently reviewed by Mr. Graham Veale who is the VP Engineering with Blackspur Oil Corp. The InSite J December 31, 2021 Reserves Report and the values contained therein are based on InSite's December 31, 2021 price deck (https://www.insitepc.com/pricing-forecasts). Mr. Veale holds a BSc. in Mechanical Engineering from the University of Calgary (1995) and is a registered member of the Alberta Association of Professional Engineers and Geoscientists of Alberta (APEGA). He has over 26 years of experience in petroleum and reservoir engineering, reserve evaluation, exploitation, corporate and business strategy, and drilling and completions. InSite and Mr. Veale have consented to the inclusion of the petroleum reserves and resources information in this announcement in the form and context in which it appears.

Oil and Gas Glossary and Definitions

Term	Meaning
Adjusted EBITDA:	Adjusted EBITDA is calculated as net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortisation, and adjusted to exclude certain non-cash, extraordinary and non-recurring items primarily relating to bargain purchase gains, gains and losses on financial instruments, transaction and advisory costs and impairment losses. Calima utilises adjusted EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects investments or returning capital to shareholders.
Adjusted working capital:	Adjusted working capital is comprised of current assets less current liabilities on the Company's balance sheet and excludes the current portions of risk management contracts and credit facility draws. Adjusted working capital is utilised by Management and others as a measure of liquidity because a surplus of adjusted working capital will result in a future net cash inflow to the business which can be used for future funding, and a deficiency of adjusted working capital will result in a future net cash outflow which will require a future draw from Calima's existing funding capacity.

Term	Meaning
ARO / Asset Retirement Obligation:	the process of permanently closing and relinquishing a well by using cement to create plugs at specific intervals within a well bore
Available funding:	Available funding is comprised of adjusted working capital and the undrawn component of Blackspur's credit facility. The available funding measure allows Management and other users to evaluate the Company's liquidity.
Credit Facility Interest:	Borrowings under the Credit Facility incur interest at a market-based interest rate plus an applicable margin which varies depending on Blackspur's net debt to cash flow ratio. Interest charges are between 150 bps to 350 bps on Canadian bank prime borrowings and between 275 bps and 475 bps on Canadian dollar bankers' acceptances. Any undrawn portion of the demand facility is subject to a standby fee in the range of 20 bps to 45 bps. Security for the credit facility is provided by a C$150 million demand debenture
CO2e:	carbon dioxide equivalent
Conventional Well:	a well that produces gas or oil from a conventional underground reservoir or formation, typically without the need for horizontal drilling or modern completion techniques
Compression:	a device or facility located along a natural gas pipeline that raises the pressure of the natural gas flowing in the pipeline, which in turn compresses the natural gas, thereby both increasing the effective capacity of the pipeline and allowing the natural gas to travel longer distances
Corporate Decline:	consolidated, average rate decline for net production from the Company's assets
Exit Production:	Exit production is defined as the average daily volume on the last week of the period
Operating Income:	Oil and gas sales net of royalties, transportation and operating expenses
Financial Hedge:	a financial arrangement which allows the Company to protect against adverse commodity price movements, the gains or losses of which flow through the Company's derivative settlements on its financial statements
Free Cash Flow (FCF):	represents Hedged Adjusted EBITDA less recurring capital expenditures, asset retirement costs and cash interest expense
Free Cash Flow Yield:	represents free cash flow as a percentage of the Company's total market capitalisation at a certain point in time
Funds Flow:	Funds flow is comprised of cash provided by operating activities, excluding the impact of changes in non-cash working capital. Calima utilises funds flow as a measure of operational performance and cash flow generating capability. Funds flow also impacts the level and extent of funding for investment in capital projects, returning capital to shareholders and repaying debt. By excluding changes in non-cash working capital from cash provided by operating activities, the funds flow measure provides a meaningful metric for Management and others by establishing a clear link between the Company's cash flows, income statement and operating netbacks from the business by isolating the impact of changes in the timing between accrual and cash settlement dates.
Gathering & Compression (G&C):	owned midstream expenses; the costs incurred to transport hydrocarbons across owned midstream assets
Gathering & Transportation (G&T):	third-party gathering and transportation expense; the cost incurred to transport hydrocarbons across third-party midstream assets
G&A:	general and administrative expenses; may be represented by recurring expenses or non-recurring expense
Hedged Adjusted EBITDA:	EBITDA including adjustments for non-recurring and non-cash items such as gain on the sale of assets, acquisition related expenses and integration costs, mark-to-market adjustments related to the Company's hedge portfolio, non-cash equity compensation charges and items of a similar nature;
Hyperbolic Decline:	non-exponential with subtle multiple decline rates; hyperbolic curves decline faster early in the life of the well and slower as time increases
LMR:	The LMR (Liability Management Ratio) is determined by the Alberta Energy Regulator ("AER") and is calculated by dividing Blackspur's deemed assets by its deemed liabilities, both values of which are determined by the AER.
LOE:	lease operating expense, including base LOE, production taxes and gathering & transportation expense
Midstream:	a segment of the oil and gas industry that focuses on the processing, storing, transporting and marketing of oil, natural gas, and natural gas liquids
Net Debt"	Net debt is calculated as the current and long-term portions of Calima's credit facility draws, lease liabilities and other borrowings net of adjusted working capital. The credit facility draws are calculated as the principal amount outstanding converted to Australian dollars at the closing exchange rate for the period. Net debt is an important measure used by Management and others to assess the Company's liquidity by aggregating long-term debt, lease liabilities and working capital.
NGL / Natural Gas Liquids:	hydrocarbon components of natural gas that can be separated from the gas state in the form of liquids
Net Debt/Adjusted EBITDA (Leverage)	a measure of financial liquidity and flexibility calculated as Net Debt divided by Hedged Adjusted EBITDA
Net Revenue Interest:	a share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest. It is the percentage of production that each party actually receives
Operating Costs:	total lease operating expense (LOE) plus gathering & compression expense
Operating Netback:	Operating netback is calculated on a per boe basis and is determined by deducting royalties, operating and transportation from oil and natural gas sales, after adjusting for realised hedging gains or losses. Operating netback is utilised by Calima and others to assess the profitability of the Company's oil and natural gas assets on a standalone basis, before the inclusion of corporate overhead related costs. Operating netback is also utilised to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes.
Physical Contract:	a marketing contract between buyer and seller of a physical commodity which locks in commodity pricing for a specific index or location and that is reflected in the Company's commodity revenues Production Taxes: state taxes imposed upon the value or quantity of oil and gas produced
Promote:	an additional economic ownership interest in the jointly-owned properties that is conveyed cost-free to the operator in consideration for operating the assets
PDP/ Proved Developed Producing:	a reserve classification for proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
PV10:	a standard metric utilised in SEC filings for the valuation of the Company's oil and gas reserves; the present value of the estimated future oil and gas revenues, reduced by direct expenses, and discounted at an annual rate of 10%
RBL / Reserve Based Lending	a revolving credit facility available to a borrower based on (secured by) the value of the borrower's oil and gas reserves
Royalty Interest or Royalty:	Interest in a leasehold area providing the holder with the right to receive a share of production associated with the leasehold area
Terminal decline:	represents the steady state decline rate after early (initial) flush production
tCO2:	Tonnes of Carbon Dioxide
Unconventional Well:	a well that produces gas or oil from an unconventional underground reservoir formation, such as shale, which typically requires hydraulic fracturing to allow the gas or oil to flow out of the reservoir

Term	Meaning
Upstream:	a segment of the oil and gas industry that focuses on the exploration and production of oil and natural gas
Working Capital Ratio:	The working capital ratio as the ratio of (i) current assets plus any undrawn availability under the facility to (ii) current liabilities less any amount drawn under the facilities. For the purposes of the covenant calculation, risk management contract assets and liabilities are excluded.
WI/ Working Interest:	a type of interest in an oil and gas property that obligates the holder thereof to bear and pay a portion of all the property's maintenance, development, and operational costs and expenses, without giving effect to any burdens applicable to the property

Abbreviation	Abbreviation meaning	Abbreviation	Abbreviation meaning
1P	proved reserves	**A$ or AUD**	Australian dollars
2P	proved plus Probable reserves	**C$ or CAD**	Canadian dollars
3P	proved plus Probable plus Possible reserves	**US$ or USD**	United states dollars
bbl or bbls	barrel of oil	**($ thousands)**	figures are divided by 1,000
boe	barrel of oil equivalent (1 bbl = 6 Mcf)	**($ 000s)**	figures are divided by 1,000
d	suffix – per day	**Q1**	first quarter ended March 31st
GJ	gigajoules	**Q2**	second quarter ended June 30th
mbbl	thousands of barrels	**Q3**	third quarter ended September 30th
mboe	thousands of barrels of oil equivalent	**Q4**	fourth quarter ended December 31st
Mcf	thousand cubic feet	**YTD**	year-to-date
MMcf	million cubic feet	**YE**	year-end
PDP	proved developed producing reserves	**H1**	six months ended June 30th
PUD	Proved Undeveloped Producing	**H2**	six months ended December 31st
C	Contingent Resources – 1C/2C/3C – low/most likely/high	**B**	Prefix – Billions
Net	Working Interest after Deduction of Royalty Interests	**MM**	Prefix - Millions
NPV (10)	Net Present Value (discount rate), before income tax	**M**	Prefix - Thousands
EUR	Estimated Ultimate Recovery per well	**/d**	Suffix – per day
WTI	West Texas Intermediate Oil Benchmark Price	**bbl**	Barrel of Oil
WCS	Western Canadian Select Oil Benchmark Price	**boe**	Barrel of Oil Equivalent (1bbl = 6 mscf)
1P or TP	Total Proved	**scf**	Standard Cubic Foot of Gas
2P or TPP	Total Proved plus Probable Reserves	**Bcf**	Billion Standard Cubic Foot of Gas
3P	Total Proved plus Probable plus Possible Reserves	**tCO_2**	Tonnes of Carbon Dioxide
EBITDA	Earnings before interest, tax, depreciation, depletion and amortisation	**OCF**	Operating Cash Flow, ex Capex
Net Acres	Working Interest	**E**	Estimate
IP24	The peak oil production rate over 24 hours of production	**CY**	Calendar Year
IP30	Average oil production rate over the first 30 days		

Calima Energy Ltd ACN 117 227 086
Suite 4, 246-250 Railway Parade, West Leederville WA 6007: +61 8 6500 3270
Fax: + 61 8 6500 3275 Email: info@calimaenergy.com www.calimaenergy.com

Appendix A: Insite Petroleum Consultants Ltd - Forecast Prices and Costs Assumptions

InSite prepared the reserve estimate based on the price deck below.

INSITE PETROLEUM CONSULTANTS LTD.
FORECAST PRICES AND COSTS ASSUMPTIONS
December 31, 2021

YEAR	WTI @ CUSHING $US/BBL	BRENT BLEND $US/BBL	CDN/US EXCHANGE RATE $C/BBL	WTI @ CUSHING $C/BBL	EDM REF PRICE $C/BBL	HARDISTY 25 API $C/BBL	WESTERN CANADA SELECT $C/BBL	HEAVY 12 API $C/BBL	CONDEN-SATE $C/BBL	BUTANE $C/BBL	PROPANE $C/BBL	ETHANE $C/BBL
2022	72.50	75.50	0.790	91.77	86.77	74.27	74.77	68.27	91.11	56.40	39.05	11.73
2023	69.00	72.00	0.800	86.25	81.25	69.25	71.25	64.75	86.13	48.75	36.56	10.68
2024	67.00	70.06	0.800	83.75	78.75	66.51	68.25	62.01	84.26	47.25	35.44	9.98
2025	68.34	71.46	0.800	85.43	80.33	67.84	69.62	63.34	85.95	48.20	36.15	10.26
2026	69.71	72.89	0.800	87.13	81.93	69.20	71.01	64.70	87.67	49.16	36.87	10.47
2027	71.10	74.35	0.800	88.88	83.57	70.58	72.43	66.08	89.42	50.14	37.61	10.70
2028	72.52	75.84	0.800	90.65	85.24	71.99	73.88	67.49	91.21	51.14	38.36	10.93
2029	73.97	77.35	0.800	92.47	86.95	73.43	75.35	68.93	93.03	52.17	39.13	11.16
2030	75.45	78.90	0.800	94.32	88.69	74.90	76.86	70.40	94.89	53.21	39.91	11.40
2031	76.96	80.48	0.800	96.20	90.46	76.40	78.40	71.90	96.79	54.28	40.71	11.64
2032	78.50	82.09	0.800	98.13	92.27	77.93	79.97	73.43	98.73	55.36	41.52	11.88
2033	80.07	83.73	0.800	100.09	94.11	79.49	81.57	74.99	100.70	56.47	42.35	12.14
2034	81.67	85.40	0.800	102.09	96.00	81.08	83.20	76.58	102.72	57.60	43.20	12.39
2035	83.31	87.11	0.800	104.13	97.92	82.70	84.86	78.20	104.77	58.75	44.06	12.65
2036	84.97	88.85	0.800	106.22	99.87	84.35	86.56	79.85	106.87	59.92	44.94	12.92
2037	86.67	90.63	0.800	108.34	101.87	86.04	88.29	81.54	109.00	61.12	45.84	13.19
2038	88.41	92.44	0.800	110.51	103.91	87.76	90.05	83.26	111.18	62.35	46.76	13.47
2039	90.17	94.29	0.800	112.72	105.99	89.51	91.86	85.01	113.41	63.59	47.69	13.75

YEAR	HENRY HUB $US/MMBTU	AECO C C$/MMBTU	ALBERTA 1 YR FIRM C$/MMBTU	ALBERTA SPOT C$/MMBTU	AGGRE-GATOR C$/MMBTU	ALBERTA AGRP C$/MMBTU	SASK SPOT C$/MMBTU	SUMAS SPOT C$/MMBTU	BC STN 2 C$/MMBTU	DAWN C$/MMBTU	SULPHUR $/LT
2022	4.00	3.55	3.35	3.35	3.20	3.35	3.40	4.70	3.45	4.96	60.00
2023	3.50	3.25	3.05	3.05	2.90	3.05	3.10	4.40	3.15	4.28	61.20
2024	3.20	3.05	2.84	2.84	2.69	2.85	2.89	3.95	2.95	3.95	62.42
2025	3.26	3.13	2.92	2.92	2.77	2.93	2.97	4.05	3.03	4.03	63.67
2026	3.33	3.19	2.98	2.98	2.83	2.99	3.03	4.13	3.09	4.11	64.95
2027	3.40	3.26	3.04	3.04	2.89	3.06	3.09	4.22	3.16	4.19	66.24
2028	3.46	3.32	3.10	3.10	2.95	3.12	3.15	4.30	3.22	4.28	67.57
2029	3.53	3.39	3.16	3.16	3.01	3.19	3.21	4.39	3.29	4.37	68.92
2030	3.60	3.46	3.22	3.22	3.07	3.26	3.27	4.48	3.36	4.45	70.30
2031	3.68	3.52	3.29	3.29	3.14	3.32	3.34	4.57	3.42	4.54	71.71
2032	3.75	3.60	3.35	3.35	3.20	3.40	3.40	4.67	3.50	4.64	73.14
2033	3.82	3.67	3.42	3.42	3.27	3.47	3.47	4.76	3.57	4.73	74.60
2034	3.90	3.74	3.49	3.49	3.34	3.54	3.54	4.86	3.64	4.83	76.09
2035	3.98	3.82	3.56	3.56	3.41	3.62	3.61	4.96	3.72	4.92	77.62
2036	4.06	3.89	3.63	3.63	3.48	3.69	3.68	5.06	3.79	5.02	79.17
2037	4.14	3.97	3.70	3.70	3.55	3.77	3.75	5.16	3.87	5.12	80.75
2038	4.22	4.05	3.77	3.77	3.62	3.85	3.82	5.27	3.95	5.23	82.37
2039	4.31	4.13	3.85	3.85	3.70	3.93	3.90	5.38	4.03	5.33	84.01

Note: All prices escalated at 2% per year after 2039
All costs escalated at 2% per year after 2022
First year forecast is for 12 months

Calima Energy Ltd ACN 117 227 086
Suite 4, 246-250 Railway Parade, West Leederville WA 6007: +61 8 6500 3270
Fax: + 61 8 6500 3275 Email: info@calimaenergy.com www.calimaenergy.com