25 February 2021

MERGER WITH BLACKSPUR OIL CORP.

- **Binding agreement to acquire 100% of Blackspur Oil Corp ("Blackspur"), a western Canadian conventional oil-weighted energy producer.**
    - Consideration of C$17 million; comprised C$12.1 million in Calima shares and a cash payment of up to C$4.9 million; plus contingent consideration tied to net debt adjustments at closing (A$1:C$1).
- **Focused High Quality Asset Base:** Blackspur's operations include high quality, producing assets in Alberta Canada with an oil weighted reserve base:
    - Net Reserves[1]:
        - 5.4 MMboe Proved Developed Producing **(**PDP)
        - 16.7 MMboe Total Proved (1P)
        - 22.5 MMboe Total Proved and Probable (2P)
    - 2020 Q4 average production: ~2,600 boe/d
    - Average 2021 forecast production: ~3,000 boe/d (65% oil)[2]
    - Estimated Dec 2021 production: ~3,400 boe/d (65% oil)[2]
    - Low-cost production: US$26/bbl WTI break-even cost
- **Substantial Growth Upside:**
    - Planned organic growth to over 5,500 boe/d by drilling 24 low risk proven undeveloped (PUD) wells by year end 2022[3].
    - In Q3 2018, Blackspur averaged production of 4,400 boe/d and peaked over 5,000 boe/d.
    - Large drilling inventory with greater than 60 booked PUD locations[1]
- **Significant Historical Investment:** C$200 million invested in Blackspur assets over the last 7 years.
- **Leveraged to Oil & Gas Price Recovery:** The Blackspur low-cost oil producing assets will give the larger Company a recurring cash flow stream and exposure to improving oil prices, while the significant resource base of the Calima Lands in the Montney gives upside to both improving oil and gas prices and LNG development in Canada.

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1 Refer Appendix one
2 This forecasted production is based on current PDP production, plus production additions from drilling 6 Sunburst wells and 3 Sparky wells in 2021 based on ~US$53.00/bbl WTI, US$12 WTI/WCS differential, ~C$2.70/mcf AECO, 1.28 USD/CAD
3 This forecasted production is based on current PDP production, plus 2021 wells above and 2022 year end average of drilling 9 Sunburst and 6 Sparky wells including existing production based on ~US$50.00/bbl WTI, US$13 WTI/WCS differential, ~C$2.40/mcf AECO, 1.28 USD/CAD

- **High Quality Management Team:** Management and operations led by Jordan Kevol, as CEO and Director supported by Blackspur and Calima management.
- **Liquidity and Financing:** Calima to undertake a capital raising of no less than A$34 million to fund the acquisition, reduce Blackspur indebtedness, provide working capital and cover transaction costs.
- **Environmental Technology:** Existing investment by Blackspur in regenerative, proprietary H_2S removal technology will also position Calima with the ability to lower its CO_2 emission rates versus peers and offers a number of positive economic & environmental benefits vs. traditional technology.
- **Board & Shareholder support:** The respective boards and major shareholders of Calima and Blackspur have approved the transaction with the deal expected to close in April 2021.

Calima Energy Limited (**ASX:CE1**) (**"Calima" or the "Company"**) is pleased to announce that it has entered into a binding agreement to acquire 100% of the issued share capital of Blackspur Oil Corp. (**"Blackspur"**), a privately held Canadian company which owns producing oil and natural gas assets in two core areas within Alberta, at Brooks and Thorsby **("the Acquisition"**).

Blackspur's operations include two high quality assets with 2P reserves of 22.5 MMboe, 1P reserves of 16.7 MMboe and PDP reserves of 5.4 MMboe. Q4 2020 production average of 2,600 boe/d (70% oil).

The successful merger with Blackspur will transform Calima to a high margin oil & gas producer leveraged to WTI pricing targeting > 5,500 boe/d by December 2022 plus exposure to rising natural gas prices via its strategic holdings in the Montney Formation.

The deal is valued at C$60,000,000 (inclusive of C$43,000,000 in debt) plus working capital adjustments and includes all assets, reserves, production and the management team of Blackspur.

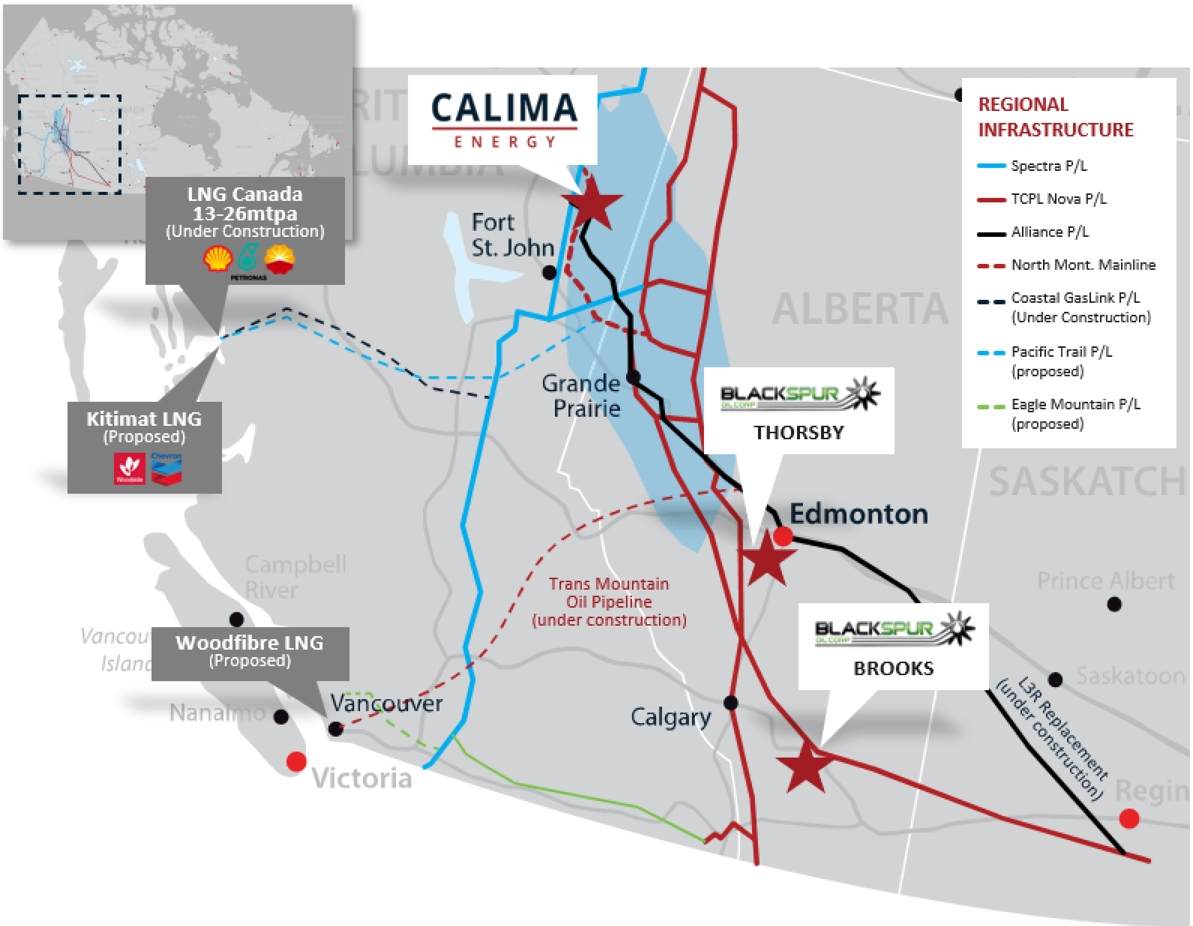
Net Reserves[4]	• PDP: 5.4 MMboe – 3.29 MMbbl oil and 12.83 Bcfg • TP (1P): 16.7 MMboe - 11.0 MMbbl oil and 33.95 Bcfg • TPP (2P): 22.5 MMboe - 14.7 MMbbl oil and 47.01 Bcfg
Acquisition Metrics	• EV/Production: C$23,077/boe • PDP: C$11.06/boe • TP (1P): C$3.59/boe • TPP (2P): C$2.66/boe

[4] Refer Appendix one

Over the past 7 years, Blackspur has invested over C$200 million acquiring and developing its assets while creating inventory and infrastructure to accommodate growth to over 10,000 boe/d.

Calima and Blackspur will combine management teams in Canada and Jordan Kevol will become CEO and President of Calima.

Figure 1. Consolidated Assets



Key Terms of the Acquisition

The base consideration payable to Blackspur shareholders is C$17 million, comprised of no less than C$12.1 million in Calima equity and up to C$4.9 million in cash. The agreement also includes contingent consideration component of up to C$4.5 million in Calima shares based on the net debt position of Blackspur upon closing (currently this adjustment is estimated to be ~C$3.2 million following reduced net debt as a result of improved Blackspur cashflows).

In addition to paying the cash consideration to Blackspur shareholders, the funds raised will be used to reduce Blackspur's credit facilities with National Bank of Canada from C$43 million to approximately C$13 million on a C$20 million revolving credit facility; providing an undrawn bank capacity of C$7 million to achieve strategic goals.

Calima has signed binding agreements with Blackspur and has received support agreements from 70% of Blackspur shareholders to date, which is sufficient to meet regulatory hurdles for completion. Calima has placed C$1 million in escrow to secure the transaction and has undertaken extensive due diligence on the Blackspur assets. Closing is expected late-April 2021, pending both the Company and Blackspur shareholder and regulatory approvals and satisfaction of the other conditions of the Acquisition.

The ASX has confirmed that Listing Rules 11.1.2 and 11.1.3 do not apply to the Acquisition.

A summary of the material terms of the Acquisition is set out in the Schedule to this announcement.

Glenn Whiddon, Calima's Chairman Comments

"The merger with Blackspur creates an emerging oil and gas producer with production and current operating cashflow of ~C$1.8million/mth in addition to a substantial reserve and resource base for future growth. At US$50 WTI the growth model is self-funding (including debt repayments) on the path to 5,500 boe/d and operating cashflow of ~C$3.5 million/mth[5]. The Montney acreage offers material upside exposure to rising gas prices from the growth of the LNG industry in Canada and North American demand. We look forward to combining with the Blackspur team and growing the Company for all shareholders going forward."

Jordan Kevol, CEO of the combined Company states:

"Blackspur is excited to be merging with Calima as it provides all shareholders an opportunity to unlock value in the Blackspur assets, as well as future growth within the Western Canadian Sedimentary Basin. The growth opportunity from a cashflow perspective enables Blackspur to leverage its position to grow production organically and through acquisitions within a top tier country. Post-merger, Blackspur's strong balance sheet and asset base, along with a low environment liability (ARO), will be an ideal combination to take advantage of current market conditions."

[5] This forecasted production is based on current PDP production, plus production additions from drilling 6 Sunburst wells and 3 Sparky wells in 2021, plus production additions from drilling 9 Sunburst wells and 6 Sparky wells in 2022. These wells are included in Blackspur's reserve report as proven undeveloped drilling locations. The operating cash flow is based on US$50 WTI, -US$13 WCS differential, 1.28 CAD/USD FX rate, $2.40/mmbtu AECO, corporate average royalty rates of 18% and operating costs assumptions that are based off historical financial statements.

Overview of Blackspur and its Assets

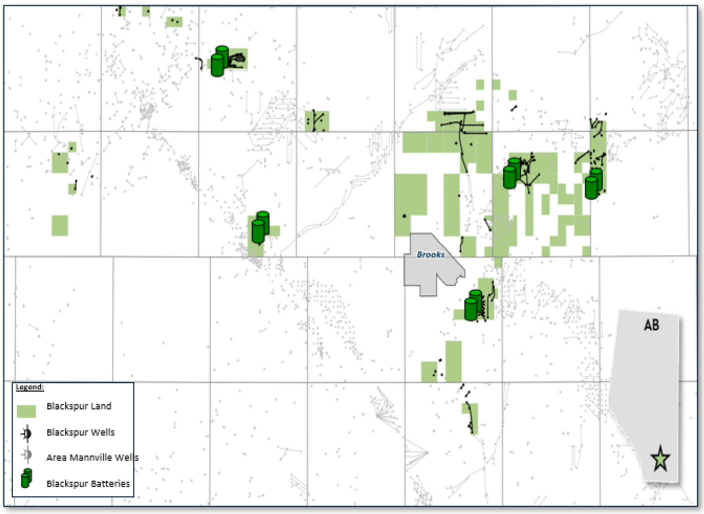
Blackspur was formed in 2012 and followed through with acquisitions of $74 million and drilled 59 oil wells funded via a combination of equity and debt. In Q3 2018 Blackspur reached peak production of over 5,000 boe/d.

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 ~4.63 with undiscounted ARO estimated at ~$14.2 million.

Brooks

Blackspur has established a core position of land (~83 net sections) and significant infrastructure that creates a foundation for growth and expansion with year-round access. The Brooks asset averaged production of a net ~1,860 boe/d in Q4 2020 with a 94% working interest. Blackspur has drilled 48 wells to date.

Brooks production comes from the Sunburst and Glauconitic formations. The Sunburst Formation can be developed at low cost (<C$1m per well) delivering economic rates of return. Blackspur's existing infrastructure can process up to 7,000 bbl/d oil.



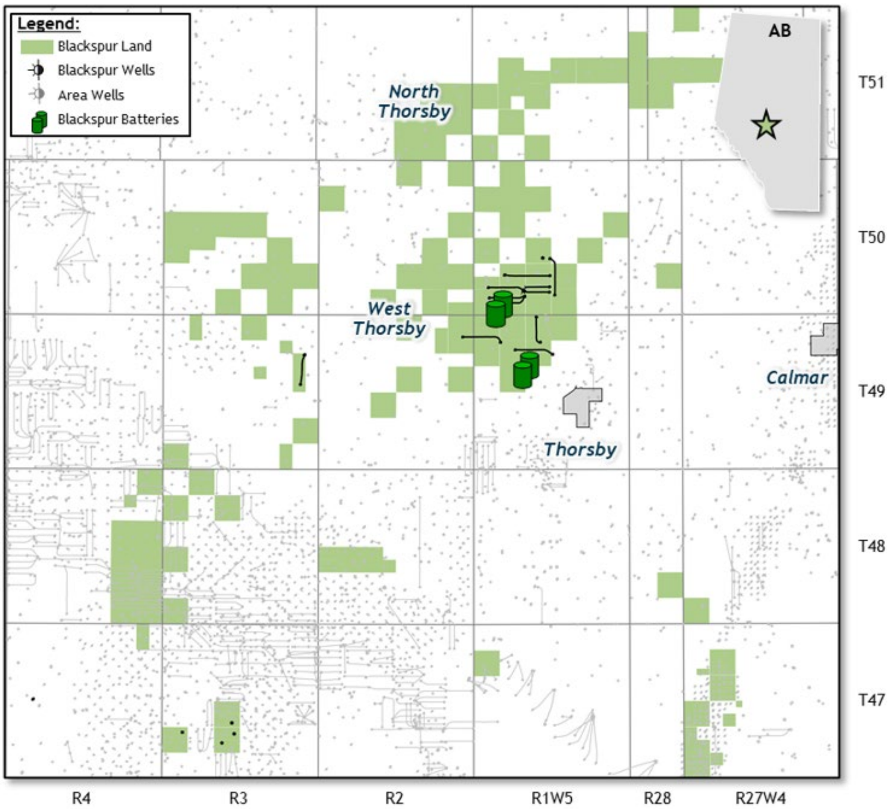
Future growth from the Brooks asset will come from the 147 net locations that have already been identified. These locations include the booked 16 Sunburst and 17 Glauconitic PUDs. Additional reserves are expected to be realized through implementation of enhanced oil recovery projects. Blackspur recently initiated a waterflood in the Countess J2J Pool which is expected to show results in the near term.

Thorsby

Thorsby provides a consolidated land base of ~108 net sections that will be efficiently developed through a network of multi-well pads. The Thorsby asset has year-round access and averaged production of ~740 boe/d in Q4 2020 (100% WI) in the Sparky Formation. Blackspur has drilled 11 wells to date.

Blackspur has spent over C$5 million building infrastructure in the Thorsby area and has existing oil processing capacity of 3,000 bbl/d oil.

Thorsby has a large inventory of wells to drill with 89 Sparky Formation and 12 Nisku Formation wells identified, which includes 28 Sparky PUD locations. Additionally, upside exists in 66 net sections of Duvernay Formation lands that are included in the Acquisition.



Thorsby Area Land Map

Calima Lands – Montney – Development Pending

Calima holds a 10-year Continuation Lease over 49 sections (33,643 acres) of land awarded as a result of the 2019 drilling campaign on the Calima Lands. 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 pipeline to connect the Calima well-pad with regional pipeline and processing infrastructure. The pipeline 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 bbls/d of wellhead condensate through to the North River Midstream sales line, providing access to the Canadian and US markets to AECO, Alliance and T-North/Station 2.

While the initial approval is for the existing two liquids rich 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. The Tommy Lakes field facilities owned by Calima lies immediately to the north of the Calima Lands, and provide:

- Cost-efficient access to North River Midstream pipeline and Jedney processing facility;
- Access to market via major pipeline networks including NGTL, Alliance and T-North;
- Gathering pipelines, compression facilities and associated facilities capable of transporting up to 50 mmcf/d of gas and 2,500 bbls/d of condensate;
- Field office with control centre and flexible camp facilities suitable for drilling operations;
- Year-round condensate storage and off-loading facilities;

The facilities are fully permitted and have been preserved for future recommissioning with annual holding costs of ~A$500,000. The facilities are in excellent condition with a replacement cost estimated at A$85 million.

Capital Raising

Calima has engaged Evolution Capital Advisors Pty Ltd (“Evolution”) as part of its capital raising efforts. The minimum raise required to complete the acquisition of Blackspur is A$34 million, which will comprise a placement to institutional and sophisticated investors and a prospectus offering to retail investors (with priority to existing Calima Shareholders). The maximum raise will be A$38 million. The capital raising is subject to shareholder approval. Evolution will be paid a 6% fee on the capital raised.

To ensure the Company has sufficient working capital to fund operations until closing of the capital raising and acquisition the Company has executed a 12 month working capital facility for the $500,000 with 6466 Investments Pty Ltd. 6466 Investments Pty Ltd is a related party to Mr Whiddon for the purposes of the Corporations Act, however Mr. Whiddon does not control this entity. This entity is owned independently of Mr. Whiddon and is only included for good corporate governance purposes. The terms of the facility are a 6% facility fee and a fixed interest amount of 10% on the amounts drawn down. It is intended that any amount drawn under this facility, if any, will be repaid at closing of the capital raising and acquisition.

Indicative Capital Structure

The indicative capital structure of Calima following completion of the Acquisition and Capital Raising is set out in the table below:

	Shares	Options	Performance Rights
On issue as at the date of this Announcement	2,207,124,112	20,750,000 (5)	19,450,000
Consideration Shares (1)	2,185,714,286	Nil	Nil
Placement Component (2)	4,857,142,857	50,000,000 (6)	96,000,000 (7)
Shares to be issued in lieu of Transaction Fees (3)	38,571,429	Nil	Nil
Loan to be converted to Shares (4)	120,464,799	Nil	Nil
On issue following completion of the Acquisition	9,409,017,482	70,750,000	19,450,000

Notes:

1. Consideration is based on an issue price of $0.007 per share, in accordance with the acquisition agreement consideration will be the same price as the placement price. Consideration of C$12.1 million plus estimated Net Debt Adjustment of C$3.2 million converted at an exchange rate of AUS$1.00:C$1.00.

2. Placement price is at $0.007 per share with minimum funds raised of A$34,000,000.

3. A total of A$270,000 of transaction costs will be converted to ordinary shares in lieu of payment of those shares.

4. The remaining loan outstanding for the Paradise well (currently circa $860,000 – but subject to change due to debt repayments made prior to conversion) will be converted to equity subject to the transaction proceeding and will be converted at placement price of $0.007.

5. 20,000,000 unlisted Options each exercisable at $0.09 or $0.12 on or before 25 August 2022; and 750,000 unlisted Options each exercisable at $0.07 on or before 6 November 2021.

6. As part of the mandate with Evolution the Company will issue 50,000,000 broker options exercisable within 3 years of issue subject to a 3-month vesting clause and exercisable at $0.01 each.

7. 96,000,000 performance rights (comprising 48,000,000 Class A performance rights and 48,000,000 Class B performance rights) under the Calima Employee Incentive Securities Plan (Plan Performance Rights) will be issued to Calima Management. It is proposed that the current directors of the Company will, subject to shareholder approval, be issued 36,000,000 performance rights (comprising 18,000,000 Class A performance rights and 18,000,000 Class B performance rights). If within 5 years of issue the below vesting conditions are met then the performance rights may be converted to shares:

   Class A performance rights vesting condition - the VWAP of the Company shares trading on the ASX being at least 1.2 cents over 20 consecutive trading days (on which shares have actually traded); and

   Class B performance rights vesting condition - the VWAP of the Company shares trading on the ASX being at least 1.6 cents over 20 consecutive trading days (on which shares have actually traded)

Indicative Use of Funds – Working Capital Program

The below table sets out the development program during the 12-month period following completion of the Acquisition.

Activity	2021 Guidance (C$)
3 x Sparky wells	7,500,000
6 x Sunburst wells	6,000,000
Total	**13,500,000**
Estimated production at 31 December 2021	**3,400 boe/d**
Estimated December 2021 monthly operating cashflow	**2,600,000**

Board Appointments

Upon completion two nominees of Blackspur; Jordan Kevol and Lonny Tetley will be appointed to the Board of the Company.

Jordan Kevol was a founder of Blackspur and has been the President and CEO since 2012. Mr Kevol holds a BSc (Geology) with 16 years of public and private Canadian junior E&P experience. Jordan is also a Director of Source Rock Royalties. Jordan will take on the role of CEO of the merged Company.

Lonny Tetley Lonny Tetley is a securities lawyer and partner at Burnet, Duckworth and Palmer LLP with over 15 years of experience in corporate finance and the oil and gas industry. Mr. Tetley serves on the Board of a number of companies including Certarus Ltd., Beyond Energy Services & Technology Corp. and Accelerate Financial Technologies Inc. He is also a member of the Private Funds Independent Review Committee of Deans Knight Capital Management Ltd.

Indicative Timetable

Announcement released on ASX	February 25, 2021
Notice of Meeting despatched to Shareholders	March 8, 2021
Calima General Meeting	April 15, 2021
Blackspur Shareholder Approval and Court Approval for Merger	April 23, 2021
Completion of Acquisition and Placement	late April 2021

*Note, this timetable is indicative only and may be subject to change.

This release has been approved by the Board.

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

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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 resources information in this announcement in relation to Calima Energy Ltd is based on, and fairly represents, information and supporting documentation in a report compiled by technical employees of McDaniel and Associates Ltd, a leading independent Canadian petroleum consulting firm registered with the Association of Professional Engineers and Geoscientists of Alberta, and was subsequently reviewed by Mr Mark Sofield who is a consultant (Havoc Services Pty Ltd) contracted to Calima Energy. Mr Sofield holds a BSc. Geology (Hons), is a Geologist with over 20 years of experience in petroleum geology, geophysics, prospect generation and evaluations, prospect and project level resource and risk estimation and is a member of the American Association of Petroleum Geologists. Mr Sofield has consented to the inclusion of the petroleum resources information in this announcement in the form and context in which it appears.

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 2019YE Reserves Report (December 31, 2019). 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 2019YE Reserves Report and the values contained therein are based on InSite's December 31, 2019 price deck (https://www.insitepc.com/pricing-forecasts). Production (net of royalties) for the year ended December 31, 2020 was ~793 mboe. 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 25 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

B or b	Prefix – Billions	BBL, BO, bbl or bo	Barrel of oil
MM or mm	Prefix – Millions	BOE or boe	Barrel of oil equivalent (1 bbl = 6 mscf)
M or m	Prefix – Thousands	CF or cf	Standard cubic feet
/ D	Suffix – per day	BCF or bcf	Billion cubic feet
G	Gas	O or o	Oil
Pj	Petajoule	E or e	Equivalent
EUR	Estimated Ultimate recovery	C	Contingent Resources – 1C/2C/3C – low/most likely/high
WI	Working Interest	NRI	Net Revenue Interest (after royalty)
PDP	Proved Developed Producing	1P	Proved reserves
PUD	Proved Undeveloped Producing	2P	Proved plus Probable reserves
IP24	The peak oil rate over 24 hrs	3P	Proved plus Probable plus Possible reserves
WTI	West Texas Intermediate	OCF	Operating Cash Flow, ex Capex
E	Estimate	YE	Year End 31 December
CY	Calendar Year	tCO_2	Tonnes of Carbon Dioxide

Appendix One - Notes to accompany Blackspur Reserves Tables and Production Disclosures and LR5 Requirements

1. The InSite 2019YE Reserves Report was ran on December 31, 2019 price deck (https://www.insitepc.com/pricing-forecasts). All reserves are quoted net after adjusting for royalty interests. Production for the year ended December 31, 2020 was ~793 mboe (net of royalties).

2. Reserve estimates based on Barrels of Oil Equivalent based on 6:1 for Natural Gas, 1:1 for Condensate and C5+, 1:1 for Ethane,1:1 for Propane, 1:1 for Butanes. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

3. Proved & Probable Reserves (2P) - Proved Reserves: Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable Reserves; Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Appendix Two - Notes to accompany Calima Resources Tables

1. Natural Gas Liquids refers to the product recovered after processing. Approximately 10 bbl/MMcf of the product recovered after processing is also condensate (C5) see also Note 2.

2. Sum of Condensate and Natural Gas Liquids. Based on Company drilling results public domain data and the results of wells drilled on adjacent land McDaniel estimate that the average condensate to gas ratio for wells in the Calima Lands would be 22.5 bbl/MMcf (wellhead condensate/gas ratio) for the Middle Montney and 17.5bbl/MMcf for the Upper Montney. Additional liquids 25bbl/MMCF would be stripped from the gas upon processing comprising 6 bbl/MMcf of C3, 9 bbl/MMcf of C4, and 10 bbl/MMcf of C5+ (Condensate).

3. Barrels of Oil Equivalent based on 6:1 for Natural Gas, 1:1 for Condensate and C5+, 1:1 for Ethane,1:1 for Propane, 1:1 for Butanes. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

4. Contingent Resources (2C) - Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently

considered to be commercially recoverable owing to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. Contingent resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status. The Contingent Resources (2C) in Tommy Lakes have been sub-classified as a "Development on Hold" and "Development Pending" as the accumulation is well defined and does represent a viable drilling target. The Contingent Resources have been classified using a deterministic method of estimation having an evaluation date of 31 March 2020.

5. Prospective resources (2U) are the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) related to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon. The Prospective Resources (2U) in Tommy Lakes have been sub-classified as a "Prospect" as the accumulation is well defined and does represent a viable drilling target. The prospective resources have also been classified using a deterministic method having an evaluation date of 31 March 2020.

6. Pre-Development – A pre-development study is an intermediate step in the development of a project scenario. The amount of information that is available for the reservoir of interest is greater than for a conceptual study. In particular, the petroleum initially in place has been reasonably well defined and the remaining uncertainty lies largely in the recovery factor and the economic viability.

7. The resources have been calculated on a reduced land position of 58,981 acres in which Calima Energy holds a 100% working interest. This includes 33,643 acres (49 sections) held under a 10-year Continuation Lease (valid to 2029) and the balance held leases that expiring in 2021/2.

Schedule One – Summary of the Material Terms of the Acquisition

1. The total consideration payable to the Blackspur Shareholders for the Acquisition is C$17,000,000 to be adjusted in accordance with the Net Debt Adjustment (if any) (see paragraph 4 below) (**"Consideration"**).
2. The Consideration will be payable to the Blackspur Shareholders at their election as either cash or Calima shares as follows:
    a. up to a maximum of C$4,900,000, being a maximum of approximately 29% of the Consideration, will be paid in cash; and
    b. up to C$17,000,000 through the issue of Calima shares at the Deemed Issue Price (as defined below) provided that no less than C$12,100,000 in value (approximately 71% of the Consideration) subject to the Net Debt Adjustment (see below) will be paid through the issue of Calima shares.
3. The deemed issue price of the Calima shares to be issued as all or part of the Consideration will be the same price per share as shares are issued pursuant to the Placement (being $0.007 per share) (**"Deemed Issue Price"**). The Deemed Issue Price will be converted from Australia dollars to Canadian dollars at the Exchange Rate for the purposes of determining the number of Calima shares to be issued in satisfaction for the Consideration. The Exchange Rate will be the exchange rate of Australian dollars to Canadian dollars at the Canadian foreign exchange rate posted by the Bank of Canada on the date that is three business days immediately prior to the date of completion of the Acquisition (**"Completion"**).
4. The parties have agreed a net working capital adjustment such that on Completion the net working capital deficit of Blackspur (**"Net Debt"**) will not exceed C$43,000,000 (pre-repayment of debt from the Placement). To the extent that the Net Debt is less than or greater than C$43,000,000 (pre-repayment of debt from the Placement), the Consideration will be increased or decreased, as applicable, by the amount that Net Debt is less or greater than C$43,000,000 up to a maximum of C$3,000,000. Further, by way of separate payment, if Net Debt is less than C$43,000,000, the Consideration will also be increased by an additional amount up to a maximum of C$1,500,000 (for each dollar that Net Debt is below C$43,000,000 (together the **"Net Debt Adjustment"**). For example, if:
    a. Net Debt is C$42,500,000, then the Net Debt Adjustment will be an increase in the Consideration of C$1,000,000;
    b. Net Debt is C$41,000,000, then the Net Debt Adjustment will be an increase in the Consideration of C$3,500,000; or
    c. Net Debt is C$44,000,000 then the Net Debt Adjustment will be a decrease in the Consideration of C$1,000,000.

The Parties are currently expecting that the Net Debt will be approximately C$41,300,000 which will result in an increase in Consideration of C$3,200,000.

5. Blackspur currently has a loan from the National Bank of Canada (**"Blackspur Loan"**). On completion of the Acquisition, the Blackspur Loan will be paid down to C$13,000,000 with C$7,000,000 available to be redrawn (pursuant to a C$20,000,000 loan facility).
6. Completion of the Acquisition is conditional upon the satisfaction or waiver of various conditions precedent including:
    a. the Company receiving firm commitments for the minimum amount to be raised pursuant to the Placement of C$33,500,000 on or before 15 March 2021;
    b. the board of directors of Blackspur unanimously approving the Acquisition and recommending that the Blackspur Shareholders vote in favour of the Acquisition and such recommendation not being withdrawn or modified;
    c. holders of not less than 66.67% of Blackspur shares present (in person or by proxy), at the shareholder meeting at which the Blackspur Shareholders consider the Acquisition voting in favour of the Acquisition;
    d. the net working capital deficit of Blackspur at Completion being no greater than C$46,000,000;
    e. any and all authorisations and approvals which may be required by law to implement the Acquisition being obtained on terms reasonably satisfactory to the parties, including approval of the Blackspur Shareholders, court approval, approvals required under the Listing Rules, the Corporations Act and any provision of a parties' associated documents or as may be required by ASIC or the ASX, including (without limitation) the approval of Shareholders for all relevant purposes;
    f. written consent being obtained from National Bank of Canada permitting the change of control caused by the Acquisition; waiving any prepayment or default provisions pursuant to the Blackspur Loan; agreeing to make the Blackspur Loan a C$20,000,000 loan facility from Completion and agreeing to postpone any demand payment obligations pursuant to the Blackspur Loan until after 30 April 2021;
    g. all of the directors of Blackspur executing customary resignations and mutual releases and the board of Blackspur being reconstituted to reflect to composition as directed by the Company;
    h. no action or proceeding pending or being threatened by any person, company, firm, government authority, securities commission, regulatory body or agency to enjoin or prohibit the Acquisition or to suspend or stop trading securities of Blackspur;
    i. no Material Adverse Change (as that term is defined in the Acquisition agreement), (or any condition, event or development involving a prospective change) in Blackspur's or Calima's business, operations, assets, capitalization, financial condition, prospects, licenses, permits, rights, privileges or liabilities, whether contractual or otherwise occurring;
    j. Blackspur obtaining all material third party consents, approvals or waivers to the Acquisition, each of which is unconditional or subject only to conditions reasonably acceptable to the Parties, including any required approvals by the Alberta Energy Regulator pursuant to Directive 067;
    k. Blackspur not being in material breach of the Blackspur Loan and having no outstanding breaches in accordance with the terms of those arrangements as at completion of the Acquisition; and
    l. completion of the Acquisition occurring by no later than 30 April 2021.
7. The Acquisition agreement contains standard commercial warranties and limits of liability as are usual for a transaction of this type.
8. The Acquisition agreement may be terminated:
    a. by mutual agreement between the parties;
    b. by Blackspur if a Break Fee or Cost Reimbursement (see paragraphs 10 and 11 below) becomes payable by Calima;
    c. by Calima if a Break Fee or Cost Reimbursement becomes payable by Blackspur;
    d. by Blackspur if the Blackspur Board accepts or recommends a Superior Proposal (as that term is defined in the Acquisition agreement), Blackspur complied with its obligations under the Acquisition agreement in respect of accepting or recommending a Superior Proposal and Blackspur has paid the Break Fee to the Company; or
    e. if any of the conditions are not satisfied or waived by the date provided for satisfaction.
9. Pursuant to the Acquisition agreement, Blackspur has the right to nominate two nominees to the Board of the Company. Upon completion of the Acquisition, the Company is proposing to appoint Jordan Kevol and P.L. (Lonny) Tetley as directors of the Company.
10. The parties have agreed a mutual break fee of C$1,000,000 (**"Break Fee"**) which will be payable in the following circumstances:
    a. The Break Fee is payable by a party in the event that that party:

i. does not recommend the Acquisition or withdraws or changes its recommendation of the Acquisition;
ii. breaches any covenant in the Acquisition agreement which breach causes or would reasonably be expected to cause a Material Adverse Change or would materially impede completion of the Acquisition and the breach is not remedied; or
iii. breaches any warranty in the Acquisition agreement which breach causes or would reasonably be expected to cause a Material Adverse Change or would materially impede completion of the Acquisition and the breach is not remedied.

b. The Break Fee is payable by Calima to Blackspur in the event that the condition in paragraph 6.a is not satisfied (Calima failing to obtain firm commitments for the Placement for at least C$33.5million by 15 March 2021).

c. The Break Fee is payable by Blackspur to Calima in the event that:
i. the Blackspur Board fails to publicly reaffirm any of its recommendations required under the Acquisition agreement;
ii. the Blackspur Board accepts or recommends a Superior Proposal (as that term is defined in the Acquisition agreement); or
iii. Blackspur is in breach of any of its covenants regarding non-solicitation in any material respect.

11. The parties have agreed a cost re-imbursement of C$500,000 (**"**Cost Reimbursement**"**) which is payable by a party in the event that that party's shareholders do not approve the Acquisition.
12. The Company has paid a deposit of C$1,000,000 held in escrow by Burnet, Duckworth and Palmer LLP which will be used to pay the Break Fees or Cost Reimbursement to the extent these fees are required to be paid and returned to Calima to the extent that these fees are not required to be paid by the Company and the Acquisition does not complete.

25 February 2021

Reserve Evaluation – Blackspur Oil Corp. Acquisition

Highlights:

- InSite Petroleum Consultants Ltd. ("InSite") has prepared a forecast prices and costs evaluation of the oil and gas properties of Blackspur Oil Corp. ("the Company" or "Corporation"). The effective date of the reserve estimates and cash flow forecasts presented in this release is December 31, 2019. The year end 2020 reserve estimates are underway by InSite.

- 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 at Cushing, Edmonton and Western Canadian Select, as well as the netback prices for 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.

- Well abandonment and reclamation costs as included in the economic runs have been estimated and prepared by the Company using the Alberta Energy Regulator (AER) Directive 11 as a base. These costs were included at the entity level for all existing wells that have been assigned reserves. Operating costs associated with inactive wells, as well as producing wells with no reserves assigned; and the costs associated with abandonment, decommissioning, reclamation and salvage of wells and facilities have been entered at the property level or corporate level as appropriate.

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

- The proved developed producing reserves net of royalties are **12.83 bcf** of gas and **3.29 mbbl** of oil and NGL's or **5.42 mboe**.

- The total proved reserves net of royalties are **33.95 bcf** of gas and **11.04 mbbl** of oil and NGL's or **16.70 mboe**.

- The total proved plus probable reserves net of royalties are **47.01 bcf** of gas and **14.68 mbbl** of oil and NGL's or **22.51 mboe**.

	Reserves (net of royalties)		
	PDP	**TP**	**P+P**
Natural Gas (mmcf)	12,825	33,953	**47,006**
Total Liquids (mbbl)	3,286	11,038	**14,679**
Totals (mboe)	5,423	16,696	**22,514**

At the effective date of the report, 31 December 2019, Blackspur held the rights to 117,039 net acres within the Brooks and Thorsby areas. The existing 61 operated wells developed approximately 7,200 net acres of this position and at the effective date Blackspur retains a Proved Developed Producing ("PDP") reserve of 5.423 million boe's after royalties from these wells.

Each year, for the purposes of estimating undeveloped reserves, a development schedule is generated which has to be appropriate and reasonable for Blackspur to execute. This development plan is prepared in consultation with InSite and takes into consideration market conditions and Blackspur'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; and
- proved well locations must be drilled within 5 years of the date they were first certified as a reserve in previous reports.

The development plan in the YE2019 Reserve Report consisted of 73 gross wells to be drilled. The schedule and breakdown in each reserve category is summarised in Table 1 below.

Period	Rig Count	Development Well Count			
		Proved (PUD)	Probable	Possible	Total
Year 1	2	13	0	0	13
Year 2	2	15	0	0	15
Year 3	2	25	0	0	25
Year 4	2	14	6	0	20
Year 5	0	0	0	0	0
Total	8	67	6	0	73

Table 1: Rig and gross well count each year of the 2019 reserve development plans.

The YE2019 development schedule assumes 15 wells to be drilled in 2021.

Table 1 above provides the total (gross) wells drilled. Blackspur has a working interest in each which dictates the reserves the Company can take credit for during the wells production life. On a WI well count for the proved reserve category, Blackspur had ~93% WI proved undeveloped wells in the YE2019 development plan.

There has been no change to the fundamentals of the Brooks and Thorsby undeveloped wells and InSite has made no material changes to their assumptions on future undeveloped well production performance.

This year end reserve development schedules only ever assume development of a modest portion of the total acreage position that Blackspur holds. Based on our existing leasehold position, allowing for the acreage associated with the existing producing wells, Blackspur estimates a total of approximately

250 future net wells will develop the entire reserve position. The total YE2019 development schedule corresponds to only 68.5 future net wells, or only 27% of the developable Brooks and Thorsby acreage.

The remaining undeveloped acreage that has not been considered for reserves (approximately 94% of our undeveloped Brooks and Thorsby acreage).

InSite assessed all future locations they evaluated for development to be commercial and they allocated the following oil reserves and resources to the Blackspur Brooks and Thorsby position in the YE2019 report.

Assumptions

Key assumptions used by InSite to generate the YE2019 estimates are as follows:

- The majority of reserves estimates are 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 our producing wells and all the future drills.

- Operating costs for developed producing wells are based on actuals incurred during YE2019. 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 were in agreement. 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.

- The existing PDP estimates are based on production from 61 operated wells (60.4 net wells).

- In conducting our reserve analysis, proved and probable 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 firstly 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.

- Decline analysis, oil-cut analysis and other performance/volumetric related prediction methods were used to calculate 100% of the proved producing reserves, 32% of the total proved reserves, and 30% of the proved plus probable reserves. Volumetrics/analogy/type curve analyses were used to calculate the remaining percentages.

- Type curves were not used due to the conventional nature of the reserves. The EUR assignments are largely influenced by analogy since we have reasonable production history for the producers.

- The probable reserves contained in the report are of two general types:

- Performance-related (i.e. Proved plus Probable). These reserves represent the best estimate overall. Proved reserves are a more conservative estimate of the recovery from wells. 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 and proved plus probable cases represents 26% of the Corporation’s probable reserves.
  - Future horizontal step-out wells represent 74.5% of the Corporation’s probable reserves.
  - Future vertical step-out wells represent 1.3% for the Corporation’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 percent probability that the assigned reserves could be recovered, or more on an aggregated basis.

- The production and revenue forecasts contained in the December 31, 2019 evaluation include abandonment and reclamation costs for each of the Corporation’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 separate entities at the property level.

- The five-year development plan used for this reserve report is detailed in Table 1 and assumes a multi rig program. A total of 73 gross well locations. The development plan assumes 2-6 wells per standard development unit and approximately 160 acre spacing.

- Anticipated Drilling, Completion & Tie-in well costs range from C$0.7 to C$3.1 million depending on whether it’s a Sunburst, Glauconitic or Sparky well.

- The development plan assumes an initial estimate of 6-12 days respectively to drill new wells.

- Average royalty payable on future well locations allocated a reserve in this report is ~14% over the life of the wells. The land and royalties are either Crown or Freehold and the average royalty for the PDP forecast in 2020 is 17%.

- No gas sales are assumed as all gas is consumed on the lease, therefore neither gas nor gas liquids have been included in the reserves estimates.

RESOURCE AND RESERVES DEFINITIONS AND ASSIGNMENT CRITERIA

Resource and Reserves estimates have been prepared by InSite Petroleum Consultants Ltd. (“InSite”) in accordance with standards contained in the Canadian Oil and Gas Evaluation (“COGE”) Handbook. The following resource and reserve definitions are contained in Section 5 of the COGE Handbook volume 1 and are set out by the Canadian Securities Administrators in National Instrument 51-101 and Companion Policy 51-101CP with reference to the COGE Handbook:

Resource and Reserve Definitions

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

Discovered Petroleum Initially-In-Place (Discovered PIIP) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development status and production status. These classifications are described in further detail below.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be further sub-classified based on project maturity and/or economic status. These classifications are also described in further detail below.

Undiscovered Petroleum Initially-In-Place (Undiscovered PIIP) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions[1], which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

a) *Proved Reserves*

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

b) *Probable Reserves*

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

c) Possible Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

a) Developed Reserves
Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

b) Developed Producing Reserves
Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

c) Developed Non-producing Reserves
Developed non-producing reserves are those reserves that have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

d) Undeveloped Reserves
Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to Reported Reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and

- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are 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.

Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

a) **Low Estimate**: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

b) **Best Estimate**: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

c) **High Estimate**: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate. This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

Economic Status of Resource Estimates

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to sub-classify contingent resources by economic status:

a) **Economic Contingent Resources** are those contingent resources that are currently economically recoverable.

b) **Sub-Economic Contingent Resources** are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is “undetermined” (i.e., “contingent resources – economic status undetermined”).

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e., specified economic conditions, which are generally accepted as being reasonable (refer to COGEH Volume 2, Section 5.8).

Commercial Risk Applicable to Resource and Reserve Estimates

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the chance of commerciality." The chance of commerciality varies in different categories of recoverable resources as follows:

a) **Reserves**: To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

b) **Contingent Resources**: Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

c) **Prospective Resources**: Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components - the chance of discovery and the chance of development.

TABLE 6
INSITE PETROLEUM CONSULTANTS LTD.
FORECAST PRICES AND COSTS ASSUMPTIONS

December 31, 2019

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
2020	61.00	66.00	0.760	80.26	73.26	59.76	58.76	53.76	76.93	40.29	27.84	5.77
2021	64.50	68.00	0.770	83.77	76.77	62.77	62.07	56.77	80.22	46.06	31.47	6.62
2022	66.50	70.00	0.780	85.26	78.76	64.76	64.26	58.76	82.30	51.19	33.08	7.48
2023	68.20	71.77	0.800	85.25	80.00	66.00	66.00	60.00	84.40	52.00	34.40	7.76
2024	69.90	73.54	0.800	87.38	82.38	68.38	68.10	62.38	86.91	53.54	35.63	8.15
2025	71.50	75.21	0.800	89.38	84.38	70.10	69.81	64.10	89.44	54.84	36.70	8.54
2026	73.50	77.29	0.800	91.88	86.88	72.31	72.02	66.31	92.09	56.47	37.79	8.72
2027	74.97	78.83	0.800	93.71	88.61	73.76	73.46	67.76	93.93	57.60	38.77	8.91
2028	76.47	80.41	0.800	95.59	90.38	75.23	74.93	69.23	95.81	58.75	39.77	9.10
2029	78.00	82.02	0.800	97.50	92.19	76.74	76.43	70.74	97.72	59.93	40.56	9.30
2030	79.56	83.66	0.800	99.45	94.04	78.27	77.95	72.27	99.68	61.12	41.38	9.49
2031	81.15	85.33	0.800	101.44	95.92	79.84	79.51	73.84	101.67	62.35	42.20	9.70
2032	82.77	87.04	0.800	103.47	97.84	81.43	81.10	75.43	103.71	63.59	43.05	9.90
2033	84.43	88.78	0.800	105.54	99.79	83.06	82.73	77.06	105.78	64.86	43.91	10.11
2034	86.12	90.56	0.800	107.65	101.79	84.72	84.38	78.72	107.90	66.16	44.79	10.33
2035	87.84	92.37	0.800	109.80	103.82	86.42	86.07	80.42	110.05	67.49	45.68	10.55
2036	89.60	94.21	0.800	112.00	105.90	88.14	87.79	82.14	112.25	68.84	46.60	10.77
2037	91.39	96.10	0.800	114.24	108.02	89.91	89.55	83.91	114.50	70.21	47.53	11.00

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
2020	2.50	2.05	1.85	1.85	1.70	1.85	2.00	2.20	1.70	3.24	60.00
2021	2.75	2.32	2.12	2.12	1.97	2.12	2.27	2.52	2.02	3.52	61.20
2022	3.00	2.60	2.39	2.39	2.24	2.40	2.54	2.80	2.30	3.80	62.42
2023	3.15	2.69	2.48	2.48	2.33	2.49	2.63	2.94	2.44	3.89	63.67
2024	3.25	2.81	2.60	2.60	2.45	2.61	2.75	3.09	2.59	4.01	64.95
2025	3.35	2.94	2.72	2.72	2.57	2.74	2.87	3.21	2.71	4.14	66.24
2026	3.42	3.00	2.77	2.77	2.62	2.80	2.92	3.32	2.82	4.22	67.57
2027	3.49	3.06	2.83	2.83	2.68	2.86	2.98	3.38	2.88	4.31	68.92
2028	3.56	3.12	2.88	2.88	2.73	2.92	3.03	3.44	2.94	4.39	70.30
2029	3.63	3.18	2.94	2.94	2.79	2.98	3.09	3.51	3.01	4.48	71.71
2030	3.70	3.24	3.00	3.00	2.85	3.04	3.15	3.58	3.08	4.57	73.14
2031	3.77	3.31	3.06	3.06	2.91	3.11	3.21	3.65	3.15	4.67	74.60
2032	3.85	3.37	3.12	3.12	2.97	3.17	3.27	3.71	3.21	4.76	76.09
2033	3.93	3.44	3.18	3.18	3.03	3.24	3.33	3.79	3.29	4.86	77.62
2034	4.00	3.51	3.25	3.25	3.10	3.31	3.40	3.86	3.36	4.95	79.17
2035	4.08	3.58	3.31	3.31	3.16	3.38	3.46	3.93	3.43	5.05	80.75
2036	4.17	3.65	3.38	3.38	3.23	3.45	3.53	4.01	3.51	5.16	82.37
2037	4.25	3.73	3.45	3.45	3.30	3.53	3.60	4.08	3.58	5.26	84.01

Note: All prices escalated at 2% per year after 2037
All costs escalated at 2% per year after 2020
First year forecast is for 12 months

1 *For securities reporting, the key economic assumptions will be the prices and costs used in the estimate. The required assumptions may vary by jurisdiction, for example* ***forecast prices and costs, in Canada under NI 51-101***

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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 2019YE Reserves Report (December 31, 2019). 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 2019YE Reserves Report and the values contained therein are based on InSite's December 31, 2019 price deck (https://www.insitepc.com/pricing-forecasts). Production (net of royalties) for the year ended December 31, 2020 was ~793 mboe. 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 25 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.

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Oil and Gas Glossary

B	Prefix – Billions	bbl	Barrel of oil
MM or mm	Prefix – Millions	boe	Barrel of oil equivalent (1 bbl = 6 mscf)
M or m	Prefix – Thousands	scf	Standard cubic feet
/ d	Suffix – per day	Bcf	Billion cubic feet
g	Gas	o	Oil
Pj	Petajoule	e	Equivalent
EUR	Estimated Ultimate recovery	C	Contingent Resources – 1C/2C/3C – low/most likely/high
WI	Working Interest	NRI	Net Revenue Interest (after royalty)
PDP	Proved Developed Producing	1P	Proved reserves
PUD	Proved Undeveloped	2P	Proved plus Probable reserves
TP	Total Proven	3P	Proved plus Probable plus Possible reserves