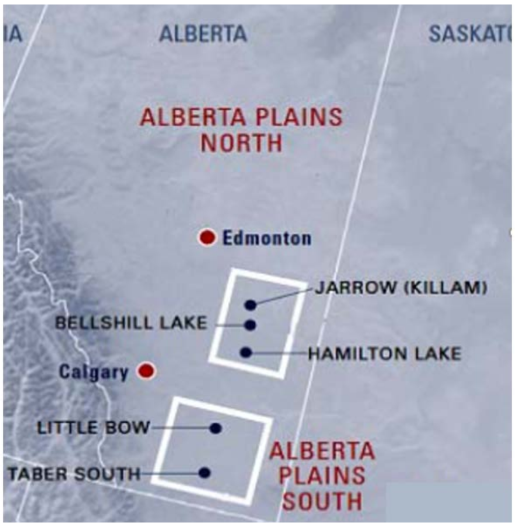
Sacgasco Limited
ABN 83 114 061 433
Unit 14, 210 Bagot Road, Subiaco, WA, 6008.
T +61 8 9388 2654 E info@sacgasco.com

Announcement to ASX **28 January 2021**

SACGASCO TO ACQUIRE 100 BOEPD IN REACTIVATED OIL FIELDS

- **Acquiring a 20% working interest in 500 BOEPD (100%) from Reactivated Oil Fields in Alberta, Canada:**
  - **Sweet Oil (86%) and Natural Gas (14%)**
- **Takes SGC's share of recently announced production acquisitions in Alberta to ~400 BOPD before further well work is implemented**
- **Purchase Price: CAD 500,000 cash (~A$510,000) and 1.92 million SGC shares at an issue price of 7.3 cents each (A$140,000):**
  - **Purchase price metric: ~US$5,000 per flowing BOPD following initial reactivation.**
- **Remaining Proved Reserves of 3.7 million BOE (100%) estimated by Independent Evaluator at 31 December 2019:**
  - **Purchase price metric: ~US$0.67 per BOE of Proved Reserves.**
- **To be Operated by efficient, low cost private Operator which provides local synergies.**
- **Acquisition funded from existing cash, with Effective date of 18 January 2021 with Closing Date prior to 10 March 2021.**
- **Drilling of Borba natural gas prospect is Sacgasco's key priority with preparations being finalized.**

Sacgasco Limited (ASX: SGC) ("Sacgasco" or "the Company") is pleased to report that it intends to acquire a 20% Working interest (**WI**) in more oil and gas producing assets ("**Assets**") in southern Alberta, Canada. The Assets consists of oil and gas fields and associated production equipment, located between Edmonton and the USA border (Refer to Map Below).



Location of Principal Asset Properties in Alberta, Canada

The principal crude oil and gas properties are located in the Little Bow, Taber and Badger areas. The acquisition by SGC is subject to the completion of the acquisition of the assets by the Vendor Blue Sky Resources Limited. 3D Seismic covers all of the producing acreage at Taber, Bellshill and Little Bow Fields.

Sacgasco's asset Purchase Price is AUD$510,000 plus the issue of 1,917,808 Sacgasco Shares to the value of AUD$140,000 valued on a 5 day VWAP price (AUD$ 0.073) prior to the January 22 2021, the date of signing of the Binding Term Sheet. A refundable deposit of AUD$102,000 has been paid. Closing of the purchase is expected by 10 March 2021.

Current production is around 100 BOPD and steps are currently being taken to bring selected wells back into production at an expected gross (100%) rate of 500 BOPD before Closing. The cost to Sacgasco of these restoration activities is AUD$170,000.

The majority of the oil and gas wells being acquired have been produced for many years. The average production for the last 5 years, before the Asset wells were shut-in during 2020 due to COVID-19 related low oil prices, was over 2,000 BOEPD. During 2019 the Asset wells averaged 1,400 BOEPD (16% Natural Gas) (Production information from official Canadian SEDAR Filings).

Gross (100%) and implied Net to SGC Remaining Reserves (Both Reserves are Net Reserves after oil and gas lease royalty has been deducted) estimated on a Deterministic Basis by independent evaluators at 31 December 2019 as follows:

Asset Reserves Table (31 Dec 2019)	100% Working Interest -Net of Royalties (BOE)	**Net Entitlement to SGC at 20% Working Interest (BOE)**
Proved Developed Producing (PDP)	3,301,800	660,360
Proved Developed Not Producing (PDNP)	272,400	54,480
Proved Undeveloped (PUD)	91,400	18,280
Total Proved (1P) Reserve	**3,665,600**	**733,120**
Probable Reserves (Prob)	*1,355,700*	*271,140*
Total Proved plus Probable (2P) Reserves	**5,021,300**	**1,004,260**

Further ASX Listing Rule 5.31 Information (Notes to Reserves) related to these reserves is provided in Attachment 1.

The purchase price is equivalent to around US$0.67 per Barrel of Proved Oil Reserves.

At current prices the Assets are cash flow positive and are highly leveraged to increased oil prices.

Representative Asset Oilfield Production Facilities

Funding

The Assets acquisition will be funded from cash reserves.

Red Earth Acquisition Update

The Operator has advised that all tasks for the requisite approval by the regulator have been completed and advice from the regulator is awaited. Closing of the transaction is expected before March 2021.

As reported in the previously announced Red Earth Acquisition (Refer ASX release "*Sacgasco to acquire 300 BOPD in Producing Oil Fields*" dated 20 November 2020) the Gross (100%) and Net to SGC Remaining Reserves were estimated on a Deterministic Basis by independent evaluators at 31 December 2019 as indicated in the Table below.

For convenience the **combined Alberta acquisitions**, including the current planned acquisition, reserve estimates at 31 December 2019 are included in the table below.

Net reserves are after oil and gas lease royalty has been deducted.

Red Earth and Assets Combined Reserves Table - SGC (31 Dec 2019)	**Net Red Earth Entitlement to SGC at 30% Working Interest**	**Net Assets Entitlement to SGC at 20% Working Interest**	**Total Net Canada entitlement to SGC after Close**
	(Barrels of Oil)	**(Barrels of Oil Equivalent)**	**(Barrels of Oil Equivalent)**
Proved Producing (PDP)	751,800	660,360	1,412,160
Proved Developed Not Producing (PDNP)	423,300	54,480	477,780
Proved Undeveloped (PUD)	135,600	18,280	153,880
Total Proved (1P) Reserve	**1,310,700**	**733,120**	**2,043,820**
Probable Reserves (Prob)	*691,500*	*271,140*	*962,640*
Total Proved plus Probable (2P) Reserves	**2,002,200**	**1,004,260**	**3,006,460**

Borba 1-7 Well Update

Preparations are on track for spudding the Borba 1-7 well in early February. The well is planned to be drilled directionally to Basement to intersect multiple stacked, 3D-seismic amplitude which are interpreted to be indicative of Natural Gas accumulations in conventional sandstone reservoirs. Natural Gas is in high demand and commands a premium price in the undersupplied California Natural Gas Market which is equivalent in size to the entire Australian domestic Natural Gas market. Sacgasco JV infrastructure is available nearby to enable a quick start to sales of discovered Natural Gas at Borba.

Sacgasco's Managing Director, Gary Jeffery commented:

"Sacgasco has had a strategy of seeking opportunities in underexplored and undervalued assets supported by invaluable infrastructure and facilities and this second transaction in Alberta with our trusted and proven Operator Blue Sky is a prime example of such assets. Our Operator has estimated that the infrastructure that is part of the current acquisition would cost around $150 million to replace. We are again capitalising on our ability to identify assets that have considerable upside and can be acquired at low prices. With the recent strength in th oil prices, and every indication that this will continue, Sacgasco is primed to benefit from this and our Operator's ability to significantly enhance current production levels.

These assets will strengthen Sacgasco's growing production and development portfolio in North America and provide Sacgasco with diversity and resilience that is complementary to the World Class opportunities for Natural Gas in the Sacramento Basin.
The assets are non-operated and are not expected to distract Sacgasco from its operated assets in the Sacramento Basin, especially the planned imminent commencement of the drilling of the Borba Prospect well which is our main priority and close to being spudded.

Sacgasco plans to use its geological and geophysical strengths to provide technical support to the operator in the interpretation of the extensive data to determine development locations to maintain and grow production.

The seller of the assets is well known to Sacgasco and have been trusted colleagues for a decade. Furthermore, Blue Sky's operating philosophy is consistent with Sacgasco's long held operating strategy.

It is our strong belief at Sacgasco, and based on my 5 decades of oil and gas experience, that neither oil nor natural gas is going to be replaced as an energy source for a considerable time, and the projected life of the acquired assets fits well with our expectations from our Sacramento natural gas assets."

For and on behalf of the Board of Sacgasco Limited.

Gary Jeffery
Managing Director
+61 8 9388 2654

Ben Jarvis
Six Degrees Investor Relations
+61 (0) 413 150 448

Attachment 1 - Notes to Reserves

Additional Information Required under Chapter 5 of the ASX Listing Rules to be read as Notes to Reserves:

The Reserves were estimated by qualified Independent Reserve Evaluator, McDaniel & Associates Consultant Ltd, and have been classified in accordance with the Canadian standards set out in the Canadian Oil and Gas Evaluation Handbook (COGEH) and National Instrument 51-101 (NI 51-101), which are in turn consistent with SPE-PRMS guidelines. They have been reviewed in detail by SGC's Competent Person, Mr Gary Jeffery.

QUALIFIED PETROLEUM RESERVES AND RESOURCE EVALUATOR REQUIREMENTS The reserves and resources information in this Sacgasco Limited Australian Stock Exchange ("ASX") document are based on and fairly represent information from a report compiled by McDaniel & Associates Consultant Ltd ("McDaniel") relating to oil and gas fields in the Asset Properties. The report was prepared effective 31 December 2019 under the supervision of Michael Verney and David Jenkinson who are qualified in accordance with ASX listing rule 5.41.

Michael Verney, P Eng. is an Executive Vice President of McDaniel, has a Bachelor of Science Degree in Civil Engineering and Bachelor of Arts degree in Economics from Queens University, and is a Registered Professional Engineer in the Province of Alberta. He is qualified in accordance with ASX listing rule 5.41.
David G Jenkinson, P.Geol. is a Vice President of McDaniel, holding a Bachelor of Science Degree in Geology from the University of Saskatchewan, and is a Registered Professional Geologist in the Province of Alberta. He is qualified in accordance with ASX listing rule 5.41

McDaniel and its named employees and associates have consented to be named in this manner in this release. McDaniel have not reviewed the Assets since January 2020 and changes may have occurred since that date.

1. The basic information employed in the preparation of the Reserve Estimates was obtained from the operator's files, public sources and from McDaniel non-confidential files. A field inspection of the properties was not conducted in view of the generally accepted reliability of the data sources for Western Canada properties. The Reserves estimates presented herein were based on the operating and economic conditions and development status as of 31 December 2019.
2. The Reserve Estimates in this release use the average forecast price and costs of McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of January 1, 2020 ("Jan 2020 Consultant Avg.") for the future crude oil, natural gas and natural gas product prices presented in Canadian dollars (Refer to Table 1 Attached).
3. The crude oil Reserves estimates presented in this release were based on a review of the volumetric data and performance characteristics of the individual wells and reservoirs in question. Volumetric estimates of the original oil in-place were based on individual well petrophysical interpretations, geological studies of pool configurations, and in some cases on published estimates. In those cases where indicative oil production decline and/or increasing gas-oil and oil cut trends were evident, the remaining reserves were determined by extrapolating these trends to economic limiting conditions. Where definitive production information was not yet available, the reserves estimates were usually volumetrically determined using recovery factors based on analogy with similar wells or reservoirs or on estimates of recovery efficiencies. The cumulative production figures were taken from published sources or from records of the Operator and estimated for those recent periods where such data were not available.

4. The natural gas reserves estimates for non-associated gas and gas cap pools were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. Volumetric estimates of the initial gas in-place were based on individual well petrophysical interpretations, geological studies of the pools and areas, and in some cases on published estimates. Material balance estimates of the initial gas in-place were employed where sufficient information was available for a reliable estimate. The reserves recoverable from the currently producing properties were estimated from studies of production performance characteristics and/or reservoir pressure histories. In those cases where indicative gas production decline and/or increasing oil-gas ratio and water-gas ratio trends were evident, the remaining reserves were determined by extrapolating these trends to economic limiting conditions. In cases of competitive drainage in multi-well pools the reserves were based on an analysis of the relevant factors relating to the future pool depletion by existing and possible future wells. The recovery factors for the non-producing properties were estimated from a consideration of test rates, reservoir pressures and by analogy with similar wells or reservoirs. Natural gas Reserves estimates for solution gas production from producing crude oil properties were based on an analysis of producing gas-oil ratios and existing sales gas recoveries. Solution gas reserves were assigned to non-producing oil properties where there was a likelihood of those reserves being recovered and sold from existing facilities or facilities that are expected to be available in the near future.
5. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore conclusions necessarily represent only informed professional judgement.
6. The Reserves have been estimated using Deterministic Methods and have been summed arithmetically and have not been adjusted for risk. The reserves are estimates and may increase and decrease as a result of market conditions, future operations including reactivations and fracture stimulations, enhanced recovery through waterfloods or changes in regulations, or actual reservoir performance. Estimates are based on certain assumptions including, but not limited to, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the Operator to recover the volumes, and that projections of future production will prove consistent with actual performance. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received , and costs incurred may vary from assumptions made.
7. The reserve estimates in the Reserves Table are Gross (100% WI- Column 1) and Net to SGC 20% WI (Column 2). Both columns represent after Deduction of Royalty Reserves.
8. The Producing Reservoirs are predominantly conventional sandstone reservoirs.
9. Sacgasco will acquire its 20% WI at Closing. SGC is acquiring a Non Operated interest. The Operator will be a Blue Sky Resources Limited company.
10. Leases are Crown (Government awarded) Leases. Many leases are Held By Production (HBP); annual rentals are paid on leases that are not HBP. Royalty paid to the Government is based upon a formula where lower producing wells attract lower royalty. In the past, based upon gross production of around 1,000 bopd, the production royalty averaged around 9%.
11. Based on local reservoir experience fracture stimulation, waterflooding and EOR may significantly increase reserves over time. The economic benefit and use of these techniques will be determine by economic analysis in the future.
12. No specialised processing of the oil is required.

Reserves Classifications used in this Release

1P Denotes higher confidence, lower estimate of Reserves (i.e., Proved Reserves).

2P Denotes the best estimate of Reserves and is the sum of Proved plus Probable Reserves.

RESERVES DEFINITIONS

The petroleum reserves estimates presented in this release have been based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the COGE Handbook. A summary of those definitions is presented below.

Reserves Categories

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

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

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

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

Development and Production Status

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

- **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 (for example, 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.
- **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.
- **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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 classification (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 + probable reserves.

Table 1

3 Consultant Average Prices (McDaniel, GLJ and Sproule)

Summary of Price Forecasts

January 1, 2020

	Crude Oil Price Forecasts							Liquids Price Forecasts				Gas Price Forecasts										
Year	WTI Crude Oil $US/bbl	Brent Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Alberta Bow River Hardisty Crude Oil $C/bbl	Western Canadian Select Crude Oil $C/bbl	Alberta Heavy Crude Oil $C/bbl	Sask Cromer Medium Crude Oil $C/bbl	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Edmonton Cond. & Natural Gasolines $/bbl	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu	Alberta Aggregator Plantgate $C/MMBtu	Empress $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)	(7)						(8)	(9)							
History																					
2009	61.80	61.60	65.90	60.30	58.58	55.30	62.80		38.60	49.25	68.15	3.95	4.20	3.95	3.90		3.87	4.05		0.3	0.880
2010	79.50	79.90	77.50	68.50	67.23	61.45	73.80		46.70	66.05	84.25	4.40	4.15	3.90	3.85		3.96	3.90		1.8	0.971
2011	95.10	111.25	95.00	78.55	77.10	67.90	88.90		55.15	76.50	104.20	4.00	3.70	3.50	3.75		3.56	3.30		2.9	1.012
2012	94.20	111.65	86.10	74.35	73.08	63.65	82.10		28.60	69.55	100.80	2.75	2.45	2.25	2.25		2.31	2.25		1.5	1.000
2013	97.95	108.60	93.05	76.55	75.25	65.25	88.25		38.90	69.40	104.65	3.75	3.20	3.00	3.00		3.10	2.90	3.08	0.9	0.971
2014	93.00	99.00	93.50	80.40	79.10	71.20	87.80		45.05	69.60	102.40	4.35	4.40	4.20	4.20	4.53	4.40	4.10	4.20	1.9	0.906
2015	48.80	52.35	57.75	46.10	44.80	39.55	51.45		6.65	35.55	60.30	2.60	2.80	2.55	2.55	3.00	2.70	2.00	2.10	1.1	0.780
2016	43.30	43.55	53.85	40.30	39.00	33.35	48.95		13.15	34.35	56.20	2.50	2.10	1.90	1.90	2.31	2.20	1.55	1.68	1.4	0.760
2017	50.90	54.25	62.85	52.00	50.70	45.20	59.85		28.90	44.60	66.85	2.95	2.40	2.15	2.15	2.83	2.35	1.75	1.88	1.6	0.770
2018	64.95	71.05	69.65	51.25	49.95	40.00	70.20		27.55	32.80	79.20	3.05	1.55	1.35	1.35	2.85	1.60	1.20	1.40	2.2	0.770
2019	56.95	64.15	68.65	59.30	58.10	54.50	67.60		17.40	23.55	70.85	2.55	1.60	1.40	1.40	2.70	1.65	0.95	1.10	2.0	0.750
Forecast																					
2020	61.00	66.33	72.64	58.43	57.57	51.23	70.29	6.42	26.36	42.10	76.83	2.62	2.04	1.84	1.84	2.59	1.94	1.46	1.66	0.0	0.760
2021	63.75	67.94	76.06	63.00	62.35	56.11	72.93	7.41	29.80	47.03	79.82	2.87	2.32	2.12	2.12	2.85	2.22	1.79	1.99	1.7	0.770
2022	66.18	70.06	78.35	64.99	64.33	57.72	74.73	8.33	32.94	50.66	82.30	3.06	2.62	2.41	2.41	3.02	2.52	2.12	2.32	2.0	0.785
2023	67.91	71.66	80.71	66.91	66.23	59.45	77.00	8.65	34.00	52.21	84.72	3.17	2.71	2.50	2.50	3.02	2.61	2.26	2.46	2.0	0.785
2024	69.48	73.27	82.64	68.65	67.97	61.09	78.87	8.98	34.88	53.48	86.71	3.24	2.81	2.60	2.60	3.12	2.70	2.35	2.55	2.0	0.785
2025	71.07	74.57	84.60	70.41	69.72	62.75	80.76	9.24	35.78	54.77	88.73	3.32	2.89	2.67	2.67	3.20	2.78	2.46	2.67	2.0	0.785
2026	72.68	76.22	86.57	72.20	71.49	64.43	82.67	9.46	36.69	56.07	90.77	3.39	2.96	2.73	2.73	3.26	2.85	2.53	2.73	2.0	0.785
2027	74.24	77.83	88.49	73.91	73.20	66.04	84.53	9.67	37.57	57.32	92.76	3.45	3.03	2.80	2.80	3.33	2.91	2.59	2.80	2.0	0.785
2028	75.73	79.36	90.31	75.53	74.80	67.55	86.29	9.89	38.41	58.50	94.65	3.53	3.09	2.86	2.86	3.40	2.98	2.66	2.86	2.0	0.785
2029	77.24	80.92	92.17	77.18	76.43	69.08	88.08	10.12	39.26	59.71	96.57	3.60	3.16	2.93	2.93	3.47	3.05	2.73	2.93	2.0	0.785
2030	78.79	82.54	94.01	78.72	77.96	70.46	89.84	10.33	40.04	60.90	98.50	3.67	3.23	2.99	2.99	3.54	3.11	2.78	2.99	2.0	0.785
2031	80.36	84.19	95.89	80.29	79.52	71.87	91.64	10.53	40.85	62.12	100.47	3.74	3.29	3.04	3.04	3.61	3.17	2.84	3.05	2.0	0.785
2032	81.97	85.87	97.81	81.90	81.11	73.31	93.47	10.74	41.66	63.36	102.48	3.82	3.36	3.11	3.11	3.69	3.23	2.89	3.11	2.0	0.785
2033	83.61	87.59	99.76	83.54	82.73	74.78	95.34	10.96	42.50	64.63	104.53	3.89	3.43	3.17	3.17	3.76	3.30	2.95	3.17	2.0	0.785
2034	85.28	89.34	101.76	85.21	84.39	76.27	97.24	11.18	43.35	65.92	106.62	3.97	3.49	3.23	3.23	3.84	3.36	3.01	3.24	2.0	0.785
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.785

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur
(2) North Sea Brent Blend 37 degrees API, 1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty, Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(8) Historical prices based on AECO 7A (near month prices). 5A (daily price) expected to be equal to 7A over long term. 2019 historical prices: 7A $1.60/MMBTU, 5A $1.75/MMBTU
(9) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations

<u>About Sacgasco Limited (ASX: SGC)</u>

Sacgasco Limited (ASX: SGC) is an Australian-based energy company focused on under-explored, recently over-looked, world class oil and gas opportunities near under-supplied markets*.*

The current prime focus is on conventional gas exploration and production in the Sacramento Basin, onshore California. Sacgasco has an extensive portfolio of natural gas producing wells and prospects at both exploration and appraisal stages, including multi-Tcf opportunities. The Company is targeting gas supply to the local Californian gas market and burgeoning LNG market in North America. Sacgasco is of the view that the size of the prospects in California have the potential to supply domestic Californian natural gas and export LNG markets.

Sacgasco is in the process of acquiring undervalued oil producing assets in Alberta, Canada to complement its current natural gas assets.

<u>www.sacgasco.com</u>

Twitter: @SacGasCo

This document contains forward looking statements that are subject to risk factors associated with the oil and gas industry. It is believed that the expectations reflected in these statements are reasonable, but they and or their timing may be affected by many variables which could cause actual results or trends to differ materially. The technical information provided has been reviewed by Mr Gary Jeffery, Managing Director of Sacgasco Limited. He is a qualified geophysicist with over 48 years technical, commercial and management experience in exploration for, appraisal and development, and transportation of oil and gas and mineral resources . Mr Jeffery is a member of the American Association of Petroleum Geologists and consents to the inclusion of the information in the form and context in which it appears.