APPENDIX A

Saturn Oil & Gas Inc.
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION
(Form 51-101F1)

Part 1 – Date of Statement

This statement of reserves data and other oil and gas information is based on the Ryder Scott Reserves Report dated March 18, 2020. The effective date of the report is December 31, 2019.

Part 2 – Disclosure of Reserves Data

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the tables contained in this filing are a summary of the oil, natural gas and natural gas liquids reserves and the value of future net revenue of Saturn Oil & Gas Inc. (the “Corporation” or “SOG”). This filing is based on the report as evaluated by Ryder Scott Petroleum Consultants (“Ryder Scott”) effective as at December 31, 2019 “Estimated Projection of Future Reserves and Income Attributable to Certain Leasehold Interests, Escalated Parameters as of December 31, 2019” for Saturn Oil & Gas Inc. (“SOG”), dated March 18, 2020, (the “Reserves Report”). Ryder Scott is an independent qualified reserves evaluator and auditor.

The Reserves Report evaluated the reserves of SOG, a crude oil producing company in Saskatchewan, Canada. The assets of SOG evaluated in the Reserves Reports are the only reserves of the Corporation and the tables below show the reserves and discounted cashflow values for the corporation.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation’s reserves estimated by Ryder Scott represent the fair market value of those reserves. The recovery and reserve estimates of the Corporation’s crude oil reserves provided are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided.

In preparing their reports, Ryder Scott relied upon certain factual information and data furnished by the Corporation with respect to ownership interests, oil, natural gas and natural gas liquids production, historical costs of operation and development, product prices, agreements relating to current and future operations, sales of production, and other relevant data. The extent and character of all factual information and data supplied were relied upon by Ryder Scott in preparing their report and was accepted as represented without independent verification. Ryder Scott relied upon representations made by the Corporation as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in their reports, between the date that the data was obtained for their evaluations and the date of their report, and that no new data has come to light that may result in a material change to the evaluation of the reserves presented in this Form 51-101F1.

The evaluations were conducted within Ryder Scott’s understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, Ryder Scott is not in a position to and did not attest to the property title, financial interest relationships or encumbrances related to the Corporation’s licenses.

The evaluations in the Reserves Reports reflect Ryder Scott’s informed judgment based on the Canadian Oil and Gas Evaluation Handbook Standards but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and engineering data. The reported hydrocarbon resources volumes are estimates based on professional engineering judgment and are subject to future revision, upward or downward, because of future operations or as additional information becomes available.

The following tables are prepared from information contained in Ryder Scott’s SOG Report as of December 31, 2019. Some of the numbers in the following tables may not appear to sum to the stated totals because of rounding in the source tables.

Reserves Data – Breakdown of Reserves

Table 2.1(1): SUMMARY OF CRUDE OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2019

VOLUMES IN IMPERIAL UNITS																	
	Oil				**Natural Gas**												
	Light, Medium and Shale		**Heavy**		**Solution**		**Conventional**		**Coalbed Methane**		**Natural Gas Liquids**		**Sulphur**		**Total BOE**	
RESERVES CATEGORY	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl	Gross MMscf	Net MMscf	Gross MMscf	Net MMscf	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl	Gross Mlt	Net Mlt	Gross MBOE	Net MBOE
PDP	875.0	851.1	-	-	-	-	-	-	-	-	-	-	-	-	875.0	851.1
PNP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PUD	2,549.4	2,485.6	188.0	185.0	-	-	-	-	-	-	-	-	-	-	2,737.5	2.670.6
TP	3,424.5	3,336.7	188.0	185.0	-	-	-	-	-	-	-	-	-	-	3,612.5	3,521.7
PB	3,512.5	3.394.5	292.9	287.6	-	-	-	-	-	-	-	-	-	-	3,805.4	3,682.1
P+P	**6,937.0**	**6,731.2**	**480.9**	**472.6**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,418.0**	**7,203.8**

Notes:

(1) See information related to BOE conversion ratio on page 21 of this document
(2) See definitions of “proved and “probable reserves on page 7 of this document.

Reserves Data – Net Present Value of Future Net Revenue

Table 2.1(2): SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2019

	BEFORE INCOME TAX (MM$)[2]					AFTER INCOME TAX (MM$)[2]					UNIT VALUE[1] BEFORE INCOME TAX DISCOUNTED AT 10%
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/BOE)[4]
RESERVES CATEGORY[3]											
PROVED											
Developed Producing	34.85	30.09	26.45	23.71	21.61	34.85	30.09	26.45	23.71	21.61	31.08
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	69.26	48.80	34.60	24.68	17.59	51.55	35.69	24.44	16.52	10.85	12.96
TOTAL PROVED	104.12	78.89	61.05	48.39	39.19	86.4	65.8	50.9	40.2	32.5	17.34
PROBABLE	128.53	79.08	50.60	33.64	23.13	92.70	55.70	34.30	21.70	14.10	13.74
TOTAL PROVED PLUS PROBABLE	**232.64**	**157.97**	**111.65**	**82.03**	**62.32**	**179.1**	**121.5**	**85.2**	**62.0**	**46.5**	**15.50**

Notes:

(1) The unit values are based on net reserves
(2) All values are presented in Canadian Dollars (CDN)
(3) See definitions of “proved” and “probable” reserves on page 7 of this document
(4) See information related to BOE conversion ratio on page 21 of this document

Table 2.1(3) TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS AT DECEMBER 31, 2019
FORECASTS PRICES AND COSTS

	REVENUE (MM$[1])	ROYALTIES AND BURDENS (MM$[2])	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	OTHER COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS[3] (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
RESERVES CATEGORY[3]									
PROVED									
Developed Producing	67.7	1.8	25.4	-	1.2	4.5	34.9	-	34.9
Developed Non-Producing	-	-	-	-	-	-	-	-	-
Undeveloped	213.8	5.0	63.8	67.2	3.6	5.0	69.3	17.7	51.6
TOTAL PROVED	281.5	6.8	89.2	67.2	4.8	9.5	104.1	17.7	86.4
PROBABLE	322.4	10.1	98.2	74.7	5.5	5.3	128.5	35.9	92.7
TOTAL PROVED PLUS PROBABLE	**604.0**	**16.9**	**187.4**	**141.9**	**10.3**	**14.8**	**232.6**	**53.6**	**179.1**

Notes:

(1) All values are presented in Canadian Dollars (CDN)
(2) Royalties and Burdens include any applicable Production Taxes
(3) Abandonment and Reclamation costs presented in this table are ONLY for wells included in the reserve report

Table 2.1(4) FUTURE NET REVENUE BY PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2019

	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (DISCOUNTED AT 10% /YEAR) (MM$)	UNIT VALUE NET RESERVE BASIS ($/MCF FOR NATURAL GAS) ($/BBL FOR CRUDE OIL AND NATURAL GAS LIQUIDS ($/BOE FOR TOTALS)[2]
RESERVES CATEGORY [1]			
Proved	Light and Medium Crude Oil (including Solution Gas and Products)	59.0	17.68
	Heavy Oil (Including Solution Gas and Products)	2.1	11.14
	Conventional Natural Gas (Including Solution Gas and Products)	-	-
	Total	61.1	17.34
Proved + Probable	Light and Medium Crude Oil (including Solution Gas and Products)	106.5	15.82
	Heavy Oil (Including Solution Gas and Products)	5.1	10.86
	Conventional Natural Gas (Including Solution Gas and Products)	-	-
	Total	**111.7**	**15.50**

Notes:

(1) See definitions of “proved” and “probable” reserves on page 7 of this document
(2) See information related to BOE conversion ratio on page 21 of this document

OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2019

Notes:

1. "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.
2. "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. There is a 90% probability that the actual remaining quantities recovered will exceed the estimated proved reserves.
3. "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.
4. "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
5. "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.
6. "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.
7. "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.
8. "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 reserve classification (Proved, Probable, Possible) to which they are assigned.

Part 3 – Pricing Assumptions

The following tables detail the benchmark reference prices, for the SOG assets in which the Corporation operated as at December 31, 2019, reflected in the reserves data disclosed above under “Part 2 - Disclosure of Reserves Data”. At the request of SOG, future hydrocarbon price parameters used in the reserve report reflect the future oil and natural gas price forecasts as published by Ryder Scott.

The table below summarizes the “benchmark prices” at the price reference point and the 2020 realized prices used for the geographic area included in the Ryder Scott report. Values are represented in Canadian currency.

Geographic Area	Product	Average Benchmark Prices	Average Realized Prices[1]
Saskatchewan	Light and Medium Crude Oil	$71.08/bbl	$87.96/bbl
	Heavy Oil	$55.74/bbl	$56.91/bbl
	Natural Gas	$ 2.11/Mcf	N/A

Note:

(1) Realized Prices are based on Net Company Revenues and Net Company Reserves

Item 3.1 – No Constant Prices used for this evaluation

Table 3.2: SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2019

	SASKATCHEWAN, CANADA (CAD)		
Year	Edmonton MSW 40° API	WCS 20.5° API	SASK. Provincial Average
	$/bbl	$/bbl	$/MMBTU
2020	71.08	55.74	2.11
2021	73.64	58.14	2.31
2022	76.86	61.16	2.52
2023	78.99	63.17	2.68
2024	81.12	65.16	2.79
2025	83.23	67.15	2.90
2026	85.86	69.62	2.94
2027	87.44	71.10	2.99
2028	89.03	72.59	3.04
2029	90.64	74.10	3.08
2030	92.29	75.65	3.13
2031	93.96	77.21	3.18
2032	95.65	78.81	3.24
2033	97.38	80.43	3.29
2034	99.13	82.07	3.34
2035	100.92	83.75	3.40
2036	102.73	85.45	3.45
2037	104.57	87.18	3.51
2038	106.45	88.94	3.56
2039+		No Further Escalation	

Part 4 – Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the changes in the Corporation's gross reserves as at December 31, 2018 against such reserves as at December 31, 2019 based on the forecast price and cost assumptions stated on pages 8 and 9 of this document.

Table 4.1a: RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2019

	Crude Oil		
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved + Probable (Mbbl)**
December 31, 2018	**2,190.6**	**2,364.4**	**4,555.0**
Extensions and Improved Recovery	1,239.6	(184.9)	1,054.7
Workovers/Interventions	-	-	-
Infill Drilling	-	-	-
Technical Revisions	(300.0)	(720.8)	(1,020.8)
Discoveries	-	-	-
Acquisitions	765.8	2,438.6	3,204.4
Dispositions	-	-	-
Economic Factors	(0.9)	(91.8)	(92.7)
Production	(282.6)	-	(282.6)
December 31, 2019	**3,612.5**	**3,805.4**	**7,418.0**

Note:

(1) See definitions of "Proved" and "Probable" Reserves on page 7 of this document
(2) Drilling (Extensions and Improved Recovery) column has a negative Total Probable reconciliation due to the substantial volume of reserves converted from probable to proven/producing.
(3) Technical revisions accounted for 12% of the total proved, 21% of the total probable and 17% of the total proved plus probable reconciliation.
(4) Company Gross Reserves exclude royalty volumes

Part 5 – Additional Information Relating to Reserves Data

5.1 Undeveloped Reserves (all volumes reported in this section are for SOG's working interest)

For SOG's eleven properties, undeveloped reserves were assigned to the Viking and Success Formations for 134 locations; of these, 69 were proved (65 Viking and 4 Success) undeveloped reserves and 65 were probable (61 Viking and 4 Success) undeveloped reserves.

The below table lists the location count by property and formation, as well as the expected on-production timing for the locations.

Saturn Property / Field	Formation	# PUDs	# PROB	Description	Gross Proved Reserves, Mbbl	Gross Proved + Probable Reserves, Mbbl	Expected OnProd Timing	Note
Prairiedale / Milton / Kerrobert 3-Area Generic Type Curve	Viking	**38**	**19**	1 mi Hz	43.3	52.3	Aug2020 – Aug2024	
Avon Hill	Viking	0	4	1 mi Hz	N/A	28.4	Aug2024 - Sept2026	1
Dodsland East	Viking	0	2	1 mi Hz	N/A	30.2	Aug2024 - Aug2026	1
Flaxcombe/Milton	Success	4	4	1/2 - 3/4 mi Hz	66.8	74.4	Mar2021 – Mar2022	4
Flaxcombe	Viking	2	0	1 mi Hz	22.3	27.8	Feb2022 – Feb2024	
Flaxcombe	Viking	1	0	1/2 mi Hz	18.6	23.6	Feb2022 – Feb2024	
Hoosier	Viking	0	4	1 mi Hz	N/A	26.3	Mar2024 - Mar2026	1
Kerrobert – based on 3-Area TC	Viking	1	1	1/2 mi Hz	34.7	41.0	Aug2021 - Aug2024	
Loverna – uses 3-Area TC	Viking	16	26	1 mi Hz	43.3	52.3	Jul2020 – Jan2023	
Milton – based on 3-Area TC	Viking	1	3	1/2 mi Hz	34.7	41.0	Oct2020 - Dec2023	
Plato North	Viking	2	0	1 mi Hz	77.9	84.7	Oct2020 – Oct2021	
Plato North	Viking	1	0	3/4 mi Hz	67.2	73.1	Nov2020	
Verendrye	Viking	0	2	1 mi Hz	N/A	42.8	Aug2022 - Aug2024	1
Whiteside	Viking	3	0	1 mi Hz	30.4	35.3	Dec2021 – Dec2023	

Notes:

1. These are areas where Saturn has no existing wells; type curves developed from analogous offsets.
2. Wells in Prairiedale, Milton and Kerrobert perform similarly, hence a generic 3-area type curve was generated.
3. EUR is estimated ultimate recovery or technical reserves; these volumes may differ from remaining reserves due to economic likits being reached.
4. Success type curves in Flaxcombe / Milton were risked by 35% to account for range of contributing wells' EUR as well as their distance from the proposed new locations.
5. Where Type Curve parameters are noted "N/A", no Proved locations exist for that Field.

The below table provides data regarding SOG's prior attributed undeveloped reserves locations:

Saturn Property / Field	Location	Formation	Year First Attributed
Plato North	1VA/08-12-027-20W3	Viking	2019
Plato North	1VA/09-12-027-20W3	Viking	2019
Plato North	1VB/09-12-027-20W3	Viking	2019
Avon Hills	1VA/09-30-029-20W3	Viking	2019
Avon Hills	1VB/09-30-029-20W3	Viking	2019
Avon Hills	1VA/16-30-029-20W3	Viking	2019
Avon Hills	1VB/16-30-029-20W3	Viking	2019
Whiteside	1VA/09-23-029-25W3	Viking	2019
Whiteside	1VB/09-23-029-25W3	Viking	2019
Whiteside	1VA/16-23-029-25W3	Viking	2019
Flaxcombe	1SA/13-18-029-26W3	Success	2019
Flaxcombe	1SA/14-18-029-26W3	Success	2019
Flaxcombe	1SA/16-29-029-26W3	Success	2019
Flaxcombe	1SA/11-29-029-26W3	Success	2019
Flaxcombe	1VA/13-29-029-26W3	Viking	2019
Flaxcombe	1VB/13-29-029-26W3	Viking	2019
Flaxcombe	1VA/04-31-029-26W3	Viking	2019
Flaxcombe	1SA/05-31-029-26W3	Success	2019
Flaxcombe	1SB/05-31-029-26W3	Success	2019
Flaxcombe	1VA/05-31-029-26W3	Viking	2019
Flaxcombe	1SA/07-31-029-26W3	Success	2019
Flaxcombe	1SB/07-31-029-26W3	Success	2019
Flaxcombe	1VA/10-31-029-26W3	Viking	2019

Saturn Property / Field	Location	Formation	Year First Attributed
Flaxcombe	1VA/11-31-029-26W3	Viking	2019
Dodsland East	1VA/16-10-030-18W3	Viking	2019
Dodsland East	1VB/16-10-030-18W3	Viking	2019
Milton	1SA/06-02-030-27W3	Success	2019
Milton	1SA/11-02-030-27W3	Success	2019
Milton	1VA/13-02-030-27W3	Viking	2019
Milton	1VA/01-09-030-27W3	Viking	2019
Milton	1VB/01-09-030-27W3	Viking	2019
Milton	1VA/10-10-030-27W3	Viking	2019
Milton	1VB/10-10-030-27W3	Viking	2019
Milton	1VA/13-10-030-27W3	Viking	2019
Milton	1VA/04-11-030-27W3	Viking	2019
Milton	1VB/04-11-030-27W3	Viking	2019
Milton	1VA/05-11-030-27W3	Viking	2019
Milton	1SA/06-11-030-27W3	Success	2019
Milton	1SA/07-11-030-27W3	Success	2019
Milton	102/12-11-030-27W3	Viking	2019
Milton	103/12-11-030-27W3	Viking	2019
Milton	1VA/02-15-030-27W3	Viking	2019
Milton	1VB/02-15-030-27W3	Viking	2019
Milton	1VA/09-15-030-27W3	Viking	2019
Milton	1VB/09-15-030-27W3	Viking	2019
Kerrobert	1VA/04-28-031-24W3	Viking	2019
Kerrobert	1VB/04-28-031-24W3	Viking	2019
Kerrobert	1VA/12-28-031-24W3	Viking	2019
Kerrobert	1VA/13-28-031-24W3	Viking	2019

Saturn Property / Field	Location	Formation	Year First Attributed
Kerrobert	1VB/13-28-031-24W3	Viking	2019
Kerrobert	1VA/01-29-031-24W3	Viking	2019
Kerrobert	1VB/01-29-031-24W3	Viking	2019
Kerrobert	1VA/14-36-031-24W3	Viking	2019
Kerrobert	1VB/14-36-031-24W3	Viking	2019
Hoosier	1VA/13-35-031-27W3	Viking	2019
Hoosier	1VB/13-35-031-27W3	Viking	2019
Kerrobert	103/09-09-032-24W3	Viking	2019
Kerrobert	104/09-09-032-24W3	Viking	2019
Hoosier	1VA/13-01-032-27W3	Viking	2019
Hoosier	1VB/13-01-032-27W3	Viking	2019
Hoosier	1VA/14-01-032-27W3	Viking	2019
Hoosier	1VB/14-01-032-27W3	Viking	2019
Hoosier	1VA/16-11-032-27W3	Viking	2019
Hoosier	1VB/16-11-032-27W3	Viking	2019
Prairiedale	101/13-35-032-27W3	Viking	2019
Prairiedale	1VA/13-35-032-27W3	Viking	2019
Plenty	1VA/01-11-033-19W3	Viking	2019
Plenty	1VB/01-11-033-19W3	Viking	2019
Prairiedale	1VA/14-06-033-26W3	Viking	2019
Prairiedale	101/15-06-033-26W3	Viking	2019
Prairiedale	1VA/15-06-033-26W3	Viking	2019
Prairiedale	1VA/16-06-033-26W3	Viking	2019
Prairiedale	101/13-01-033-27W3	Viking	2019
Prairiedale	1VB/13-01-033-27W3	Viking	2019
Prairiedale	101/14-01-033-27W3	Viking	2019

Saturn Property / Field	Location	Formation	Year First Attributed
Prairiedale	102/15-01-033-27W3	Viking	2019
Prairiedale	1VA/15-02-033-27W3	Viking	2019
Prairiedale	1VB/15-02-033-27W3	Viking	2019
Prairiedale	1VA/16-02-033-27W3	Viking	2019

5.2 Significant Factors or Uncertainties Affecting Reserves Data

The estimation of Reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Corporation's estimates are based on current production forecasts, prices and economic conditions. All of the Corporation's Reserves are evaluated by Ryder Scott, an independent engineering firm. As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Corporation to ensure that Reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves, the accuracy of the reserve estimate improves.

Certain information regarding the Corporation set forth in this report, including management's assessment of the Corporation's future plans and operations contain forward looking statements that involve substantial known and unknown risks and uncertainties. These risks include, but are not limited to the risks associated with the oil and gas industry, commodity prices and exchange rates; industry related risks that could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans; risks associated with the uncertainty of reserve estimates; health and safety risk; and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks the Corporation faces in this market. The Corporation's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, and if any of them do, what benefits the Corporation may derive therefrom. The reader is cautioned not to place undue reliance on this forward-looking information.

The Corporation anticipates that any future exploration and development costs associated with its Reserves will be financed through combinations of internally generated cashflow, debt and equity financing. As of December 31, 2019 the Corporation has 400bbls/d hedged. Hedging program expires in February 2021.

Information Concerning Abandonment and Reclamation Costs

The estimated abandonment and restoration costs used by Ryder Scott are for reserves entities only. These costs are based on discussions with the Corporation's engineering personnel who, in turn, evaluated information provided by field and technical personnel with experience in the oil and gas basins in which the company operates. The Corporation expects to incur $93,500 in abandonment and reclamation costs in 2020. All future abandonment and reclamation costs for reserve entities are deducted in determining Future Net Revenues. Only costs for wells included in the Ryder Scott reserve report have been included in the tables below.

Table 5.2: FUTURE ABANDONMENT AND RECLAMATION COSTS

Year	Total Proved Estimated Using Forecast Prices and Costs(1) (Undiscounted) (MM$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs(1) (Undiscounted) (MM$)
2020	0.1	0.1
2021	0.2	0.2
2022	0.3	0.3
Total for three years	0.6	0.6
Remainder	8.9	14.2
Total for all years	9.5	14.8

Notes:

(1) Costs reflect well abandonments for entities forecast in the reserve report.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which have been deducted in the estimation of the future net revenues of the proved and probable reserves.

Table 5.3: FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

Year	Proved Reserves MM$	Proved plus Probable Reserves MM$
2019	18.7	18.7
2020	22.1	22.1
2021	26.4	26.4
2022	-	-
2023	-	-
Remaining	-	-
Total (undiscounted)	67.2	141.9

The Corporation's current cash balance, internally-generated cash flow and future debt and equity placements could allow the Corporation to complete the development costs specified above. It is anticipated that the cost arising from debt that may be placed to fund future development activities will reflect rates for asset-based lending prevailing in Canada. The effect of the costs of the expected funding could have a material impact on the revenues or reserves currently being reported.

Part 6 – Other Oil and Gas Information

Major Properties

Prairiedale

The Prairiedale, Saskatchewan, property is located in southwest Saskatchewan in Townships 30, 31 and 32, Ranges 26 and 27 W3M, approximately 35 kilometers to the west of Kindersley, Saskatchewan. SOG holds a 100 percent working interest in several sections with opportunities for future drilling locations. Oil in the Viking Formation is targeted in this area.

Milton

The Milton, Saskatchewan, property is located in southwest Saskatchewan in Township 30, Range 27 W3M, approximately 35 kilometers to the west of Kindersley, Saskatchewan. SOG holds a 100 percent working interest in several sections with opportunities for future oil recompletions and new drilling locations. Targets in the area are oil in the Success and Viking Formations.

Kerrobert

The Kerrobert, Saskatchewan, property is located in southwest Saskatchewan in Townships 31 and 32, Range 24 W3M, approximately 20 kilometers to the west of Kindersley, Saskatchewan. SOG holds a 100 percent working interest in several sections with opportunities for future drilling locations. Oil in the Viking Formation is targeted in this area.

Flaxcombe

The Flaxcombe, Saskatchewan, property is located in southwest Saskatchewan in Townships 29 and 30, Ranges 26 and 27 W3M, approximately 35 kilometers to the west of Kindersley, Saskatchewan. SOG holds a working interest ranging between 50 and 100 percent in several sections with opportunities for future oil recompletions and new drilling locations. Targets in the area are oil in the Success and Viking Formations.

The following table sets forth the number of wells in which the Corporation held a working interest as at December 31, 2019:

Gross and Net Oil and Gas and Wells

Table 6.1: Canada - Saskatchewan

Saskatchewan	CRUDE OIL		NATURAL GAS	
	Gross	Net	Gross	Net
Producing	35	34	-	-
Non-Producing	0	0	-	-
Total	35	34	-	-

Properties with no Attributed Reserves

Table 6.2: PROPERTIES WITH NO ATTRIBUTED RESERVES

As at December 31, 2019 the Company's assets have a total acreage of 37,459 acres (net 35,024 acres). Summarized below is the portion of this acreage that is considered undeveloped (11,404.6 acres).

Location/License	Gross Area (acres)	Net Area (acres)	Work Commitments / Expiry Date	Rights to Expire within One Year
Flaxcombe/PN70681	640.0	640.0	Expiry = 2023/ 03 / 31	No
Whiteside/PN70876	640.0	640.0	Expiry = 2024/ 03 / 31	No
Whiteside/PN70875	640.0	640.0	Expiry = 2024/ 03 / 31	No
Milton/PN70891	640.0	640.0	Expiry = 2024/ 03 / 31	No
Milton/PN61796	600.0	600.0	Production Continuance	No
Kerrobert/PN70890	320.0	320.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN71062	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70974	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70971	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70979	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70969	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70978	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70977	640.0	640.0	Expiry = 2024/ 03 / 31	No
Dodsland East/PN70973	640.0	640.0	Expiry = 2024/ 03 / 31	No
Loverna/PN71228	640.0	640.0	Expiry = 2024/ 03 / 31	No
Loverna/PN71227	444.6	444.6	Expiry = 2024/ 03 / 31	No
Hoosier/PN71139	640.0	640.0	Expiry = 2024/ 03 / 31	No
Hoosier/PN71136	440.0	440.0	Expiry = 2024/ 03 / 31	No
Prairiedale/PN14621	322.0	322.0	Production Continuance	No
Prairiedale/GPN16993	320.0	320.0	Production Continuance	No

These lands have no financial commitment on them other than annual rental payments to the Ministry of Natural Resources or Freehold lessors.

6.2.1 Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

The Corporation has no significant factors or uncertainties relevant to properties with no attributed reserves

6.3 Forward Contracts

The Corporation has no forward contracts.

6.5 Tax Horizon

The Company is not expected to begin paying income tax in 2020 based on proved plus probable cash flow economics for the Canadian assets.

6.6 Costs Incurred

The following table summarizes the Corporation's capital expenditures incurred during the year ended December 31, 2019:

Table 6.6a: COSTS INCURRED IN 2019 – Canada (CAD M$)

	Property Acquisition Costs			
	Proved Properties	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Saskatchewan	718.2	205.4	3.4	16,417.3
Total	**718.2**	**205.4**	**3.4**	**16,417.3**

During 2019, the Company incurred capital expenditures of $17.3 million, including costs of all of which related to maintaining its existing and essential land portfolio.

6.7 Exploration and Development Activities

Exploration and development expenditures were $16.4 million in 2019, all of which related to maintaining its existing and essential land portfolio. In 2019, the Company will continue to maintain its existing and essential land portfolio.

Table 6.7: EXPLORATION AND DEVELOPMENT ACTIVITIES, Canada (CAD M$)

	Exploration		**Development**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
2019	3.4	3.4	16,417.3	16,417.3	16,420.7	16,420.7
Total wells			18	18	18	18
Success Rate (%)			94%	94%	94%	94%
Average Working Interest (%)			-	100%	-	100%

6.8 Production Estimates

The following table is a summary of the gross (prior to royalties) volume of the Corporation's estimated production for 2020, which is reflected in the estimate of future net revenue in the Reserves Reports based on forecast prices and costs.

Table 6.8a: ESTIMATED 2020 PRODUCTION

Full Field Interest Production Category	Light and Medium Crude Oil (Mbbl)	Heavy Oil (Mbbl)	Associated and Non-Associated Natural Gas (MMscf)	Oil Equivalent (MBOE)(1)
Gross Proved Production				
Prairiedale Field	101.3	-	-	101.3
Milton Field	48.8	-	-	48.8
Kerrobert Field	24.8	-	-	24.8
Loverna Field	100.8	-	-	100.8
Remainder of Fields	31.4	-	-	31.4
Total Proved	**307.1**	**-**	**-**	**307.1**
Gross Proved plus Probable Production				
Prairiedale Field	108.9	-	-	108.9
Milton Field	51.4	-	-	51.4
Kerrorbert Field	27.4	-	-	27.4
Loverna Field	104.3	-	-	104.3
Remainder of Fields	33.2	-	-	33.2
Total Proved plus Probable	**325.2**	**-**	**-**	**325.2**

Notes:

(1) See information related to BOE conversion ratio on page 21 of this document

6.9 Production History and Per Unit Results

The following tables summarize certain information in respect of production, product prices received royalties and production taxes paid, operating expenses and resulting netback for the periods indicated below:

Table 6.9-1: History and Per Unit Results
For Saturn Oil & Gas Inc.

SUMMARY OF
2019 COMPANY SHARE OF PRODUCTION AND NETBACKS
For Saturn Oil & Gas Inc.

RESERVE_CATEGORY	Q1	Q2	Q3	Q4	Total
Average Daily Production					
Light and Medium Crude Oil (bbls/d)	811	857	640	755	765
Natural Gas (Mcf/d)	0.0	0.0	0.0	0.0	0.0
NGLs (bbls/d)	0.0	0.0	0.0	0.0	0.0
Total (boe/d)	**811**	**857**	**640**	**755**	**765**
Average Price Received					
Light and Medium Crude Oil ($/bbl)	62.72	70.10	64.55	64.14	65.52
Natural Gas ($/Mcf)	0.0	0.0	0.0	0.0	0.0
NGLs ($/bbls)	0.0	0.0	0.0	0.0	0.0
Combined ($/boe)	**62.72**	**70.10**	**64.55**	**64.14**	**65.52**
Royalties and Production taxes					
Light and Medium Crude Oil ($/bbl)	3.16	3.04	2.93	2.35	2.88
Natural Gas ($/Mcf)	0.0	0.0	0.0	0.0	0.0
NGLs ($/bbls)	0.0	0.0	0.0	0.0	0.0
Combined ($/boe)	**3.16**	**3.04**	**2.93**	**2.35**	**2.88**
Operating Expenses (including transportation)					
Combined ($/boe)	12.85	10.04	9.71	9.89	10.67
Netback Received ($/boe)	**46.69**	**57.02**	**51.92**	**51.90**	**51.98**

Note**:** See Information related to BOE conversion ratio on page 21 of this document.

ABBREVIATIONS AND CONVERSION

CRUDE OIL AND NATURAL GAS		NATURAL GAS	
bbl	barrel	Mscf	thousand standard Cubic feet
bbls	barrels	MMscf	millions standard Cubic feet
Mbbls	thousands of barrels	MMscf/d	thousand standard Cubic feet per day
MMbbls	millions of barrels	MMBTU	million british thermal units
MSTB	1,000 stock tank barrels	Bscf	billion standard Cubic feet
bbls/d	barrels per day	GJ	gigajoule
NGLs	natural gas liquids		
STB	stock tank barrels of oil		
STB/d	stock tank barrels of oil per day		

OTHER

BOE	Barrel of oil equivalent on the basis that 1 barrel of oil is equivalent to 6 Mscf of natural gas. BOE's may be misleading, particularly if used in isolation. A BOE conversion ration of 1 barrel of oil for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.
BOE/d	Barrel of oil equivalent per day
m^3	Cubic meters