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VIRGINIA HILLS OIL CORP.

NEWS RELEASE **TSX Venture Exchange: VHO**

VIRGINIA HILLS OIL CORP. ANNOUNCES 2015 FOURTH QUARTER AND YEAR END RESULTS

March 30, 2016 – Calgary, Alberta – Virginia Hills Oil Corp. ("**Virginia Hills**" or the "**Company**") has released the results of its year end 2015 corporate reserves evaluation (the "**Sproule Report**") which were independently evaluated by Sproule Associates Limited ("**Sproule**") with an effective date of December 31, 2015 and a preparation date of March 15, 2016. Sproule evaluated 100% of the Company's reserves in 2015.

The Company also announces that its audited consolidated financial statements and the related Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2015 have been filed on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com and are available on the Company's website at www.virginiahillsoil.com.

Basis of Presentation – Historical Background

On April 15, 2015, the Company completed a corporate reorganization as part of a plan of arrangement (the "**Arrangement**") pursuant to section 193 of the *Business Corporations Act* (Alberta). Pursuant to the Arrangement, the common shareholders of Pinecrest Energy Inc. ("**Pinecrest**") became the shareholders of the Company and approximately 90% of Pinecrest's oil and gas assets, and substantially all of the other assets and liabilities were transferred to the Company. The common shares of Pinecrest were then sold to Cardinal Energy Ltd. for cash proceeds of $23.5 million, of which $1.0 million was placed into escrow to satisfy certain closing adjustments.

As a result of the Arrangement, Virginia Hills owns substantially the same assets owned by Pinecrest immediately prior to the Arrangement. The Arrangement has been accounted for on a continuity of interest basis as Virginia Hills had always carried on the business formerly carried on by Pinecrest. Unless otherwise indicated, all information presented for the pre-Arrangement period in this press release is that of Pinecrest.

Highlights for 2015:

- Increased proved ("**1P**") reserves by 43% year over year to 5.3 million barrels of oil equivalent ("**Mboe**") with a net present value, discounted at 10% ("**NPV10**") of $71.9 million and reserve life index ("**RLI**")[1] of 9.7 years;
- Increased proved plus probable ("**2P**") reserves by 20% year over year to 7.9 Mboe replacing annual production of 553,000 boes by 338%[2] with an NPV10 of $116.6 million and an RLI of 14.3 years;
- 2P Reserves were weighted 97% to light oil at year end 2015;
- Finding and Development Costs ("**F&D**"):
  - The 1P F&D costs were $5.99 per boe resulting in a recycle ratio[3] of 4.4 times;
  - The 2P F&D costs were $12.70 per boe resulting in a recycle ratio of 2.1 times;

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[1] RLI is calculated by dividing the reserves in each category by the average annual production for that period. For example 2015 Total Proven = (5,341,100) / (1,515*.365) = 9.7 years.

[2] The reserves replacement ratio is calculated by dividing the yearly change in reserves before production by the actual annual production for that year. For example: 2015 Total Proven = (5,341,1000-3,743,000+553,000)/553,000= 388%.

[3] Recycle ratio is calculated by dividing the operating netback per boe by the FD&A costs for that period. For example: 2015 Total Proven = (26.61/5.99) = 4.4. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves.

- Finding, Development and Acquisition Costs ("**FD&A**")[4]:
  - The 1P FD&A costs were $18.73 per boe resulting in a recycle ratio of 1.4 times;
  - The 2P FD&A costs were $17.34 per boe resulting in a recycle ratio of 1.5 times;
- Increased 2P reserves associated with the Company's water flood project areas by 33% year over year to 2.3 Mboe with NPV10 of $46.2 million;
- Production rates from year end 2015 proved developed producing reserves are forecast to decline in 2016 at a rate of 6.5% from 2015 average levels of 1,515 boe/d prior to the addition of capital, representing a significant improvement from average 2014 and 2015 annual decline rates of 41% and 23%, respectively;
- Achieved fourth quarter and annual 2015 production of 1,464 boe per day and 1,515 boe per day (97% light oil and NGLs), respectively; and
- Achieved operating netbacks for the fourth quarter and year to date of $32.45 per boe and $26.61 per boe respectively.

Year-end 2015 Reserves

The detailed reserves data set forth below is based upon the Sproule Report, which was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The following presentation summarizes the Company's crude oil, natural gas liquids and natural gas reserves, and the net present values before income tax of future net revenue for the Company's reserves using forecast prices and costs based on the Sproule Report. The reserves evaluation was based on Sproule forecast escalated pricing and foreign exchange rates at December 31, 2015, as outlined in the attached table entitled "Price forecast". Additional information is included in the Company's 51-101F1 which has been filed on SEDAR.

Corporate Gross Reserves (1)(2)

	As at December 31, 2015		
Reserves Category *(Forecast Prices and Costs)*	**Oil(3) (Mbbl)**	**Conventional Natural Gas (Mmcf)**	**Total (4) (Mboe)**
Proved			
Producing	3,235	382	3,382
Non-producing	59	0	59
Undeveloped	1,870	77	1,899
Total proved	5,165	459	5,341
Total probable	2,521	118	2,567
Total proved plus probable	**7,686**	**577**	**7,908**

(1) Reserves are presented on a gross basis, which is defined as Virginia Hills' working interest share (operated and non-operated properties) before deduction of royalties and without including any royalty interest in the Company.
(2) Based on Sproule's December 31, 2015 escalated price forecast.
(3) "Oil" values include all light crude oil and medium crude oil and natural gas liquids volumes.
(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. See "BOE Advisory".
(5) Columns may not add due to rounding.
(6) Pursuant to section 5.4.3 "Levels of Certainty for Reported Reserves" of the COGE Handbook, reported reserves should target at least a 90 percent probability that the quantities actually recovered will be equal to or exceed the estimated proved reserves and that at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

[4] FD&A costs are used as a measure of capital efficiency. The calculation includes all capital costs for that period plus the change in future development costs ("**FDC**") for that period. This total capital including the change in the FDC is then divided by the change in reserves for that period incorporating all revisions and production for that same period. For example: 2015 Total Proven = (5,341,100-434,800+553,000-3,743,000) / ($78,390,000-$45,993,000) = $ 18.83 per boe.

Corporate Reserve Values (1)(2)(3)

The estimated before-tax net present value ("**NPV**") of future net revenues associated with Virginia Hills' reserves, effective December 31, 2015 and based on the Sproule Report and the published Sproule price deck for December 31, 2015, is summarized in the table below.

	As at December 31, 2015				
Annual Discount Rate, before taxes $000 ***(Forecast Prices and Costs)***	**0%**	**5%**	**10%**	**15%**	**20%**
Proved					
Producing	$79,671	$67,746	$58,051	$50,464	$44,508
Non-producing	$1,531	$671	$437	$330	$261
Undeveloped	$36,609	$22,520	$13,397	$7,397	$3,340
Total proved	$117,810	$90,938	$71,885	$58,191	$48,110
Probable	$93,286	$63,039	$44,673	$33,011	$25,258
Total proved plus probable	$211,096	$153,977	$116,558	$91,202	$73,368

(1) *Future net revenue is after deduction of estimated costs of abandonment and reclamation of existing and future wells to which Sproule assigned reserves and does not include costs of abandonment and reclamation related to Virginia Hills' facilities and pipelines.*

(2) *It should not be assumed that the present worth of estimated future net revenue presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Virginia Hills' crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.*

(3) *All future net revenues are stated prior to provision for interest, general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. Future net revenues have been presented on a before tax basis*

(4) *Numbers are subject to rounding.*

Price Forecast

The Sproule December 31, 2015 price forecast is summarized in the table below:

Year	**Exchange Rate** **$US/$Cdn**	**WTI @ Cushing** **(US$/bbl)**	**Canadian Light Sweet** **(Cdn$/bbl)**	**Natural Gas Aeco-C Spot** **(Cdn$/Mmbtu)**
2016	$0.75	$45.00	$55.20	$2.25
2017	$0.80	$60.00	$69.00	$2.95
2018	$0.83	$70.00	$78.43	$3.42
2019	$0.85	$80.00	$89.41	$3.91
2020	$0.85	$81.20	$91.71	$4.20
2021	$0.85	$82.42	$93.08	$4.28
2022	$0.85	$83.65	$94.48	$4.35
2023	$0.85	$84.91	$95.90	$4.43
2024	$0.85	$86.18	$97.34	$4.51
2025	$0.85	$87.48	$98.80	$4.59
2026	$0.85	$88.79	$100.28	$4.67
After 2027+	-	+1.5%/yr	+1.5%/yr	+1.5%/yr

Reserves Overview

In 2015, Virginia Hills and its predecessor (Pinecrest) spent $10.3 million on its Red Earth Slavepoint light oil assets, which was focused on improving the economics of its undeveloped horizontal type curve, optimizing its water flood project areas and reducing its operating cost structure. The Company was successful in addressing these items and has positioned its asset base for successful development in the future within a potentially weak commodity price environment.

Proved reserves increased year over year by 43% to 5.3 Mboe from 3.7 Mboe at year end 2014 (as reported by Pinecrest in their year end 2014 corporate reserves evaluation prepared by Sproule with an effective date of December 31, 2014 and a preparation date of January 7, 2015 (the "**Pinecrest Report**")) with a NPV10 of $71.9 million. The Company's proved reserves were weighted 97% to light oil as at December 31, 2015. The RLI of the Company's proved reserves based on 2015 annual production increased by 86% from 2014 levels (as reported in the Pinecrest Report) to 9.7 years using annualized production of 1,515 boe per day in 2015.

Proved plus probable reserves increased 20%, year over year, to 7.9 Mboe with an NPV10 of $116.6 million. The Company's proved plus probable reserves are weighted 97% to light oil. The RLI of the Company's 2P reserves was 14.3 years at December 31, 2015 representing an increase of 61% when compared to the 2P reserves reported in the Pinecrest Report.

The Company's focus on optimizing and enhancing the value of its asset base has resulted in a marked improvement on its corporate base production decline and sustainability. The Sproule Report has forecasted that Virginia Hills' proved developed producing assets, before capital investment, will decline by 6.5% in 2016 from 2015 average production levels. This is substantially lower than annual decline rates experienced by Pinecrest in 2014 and by the Company in 2015 of 41% and 23%, respectively.

Proved plus probable reserves associated with Virginia Hills' water flood projects increased year over year on a per boe basis by 23% to 4.4 Mboe with NPV10 of $46.2 million. In 2015, the Company invested approximately $3.6 million on its water flood optimization projects in the greater Red Earth area and increased 2P reserves by approximately 725 Mboe representing F&D costs of $4.96 per boe. The Company continues to successfully optimize its water flood project areas with average annual gross production rates in 2014 and 2015 of 670 boe/d and 644 boe/d, respectively and current average rates over the first two months of 2016 of approximately 726 boe/d. Production from wells within the water flood project areas represented 43% and 40% of the Company's average production and NPV10, respectively, in 2015. Virginia Hills' water flood project areas at year end 2015 represent just 14% of the Company's current developed footprint in the greater Red Earth area with a total of 37 gross (28.5 net) sections of land producing economically from the Slavepoint formation under primary production and 4.5 gross (4.0 net) sections producing under secondary recovery.

Following completion of the Arrangement, the Company focused its capital on optimizing its Otter water flood areas by investing $3.3 million on 1.8 gross (1.6 net) sections located in the area. Average gross production from this project area in 2014 and 2015 was 216 boe/d and 282 boe/d, respectively with current average gross production rates for the first two months of 2016 of approximately 430 boe/d. The Company believes its performance on the Otter water flood project will become the point forward analog metrics industry wide for Slavepoint light oil water flood projects in the greater Red Earth area.

In 2015, Virginia Hills drilled 2.0 gross (2.0 net) horizontal Slavepoint light oil wells and was successful in reducing the future capital associated with each undeveloped location by 35% to $2.2 million per well compared to $3.3 million at year end 2014 (as reported by Pinecrest), while maintaining production and reserve expectations on a per well basis. This decrease in expected future cost per location was directly attributable to the significant decline in industry service costs and the introduction of both acid fracturing and slim hole mono-bore technology to the Red Earth Slavepoint light oil play. As per the Sproule Report, the Company's new Slavepoint light oil horizontal type curve has the following average attributes:

- IP30 – 145 bbls/d of light oil;
- 2P Reserves – 96 Mbbls of light oil;
- Capital - $2.2 million;
- NPV10 per well - $1.2 million (Sproule December 31, 2015 price deck); and
- Rate of Return[5] – 55%.

At year end 2015 Virginia Hills had 37.0 gross (34.8 net) Slavepoint light oil horizontal undeveloped locations booked on a 2P reserve basis in the greater Red Earth area compared to 14.0 gross (14.0 net) at year end 2014 (as reported in the Pinecrest Report). The increase in undeveloped 2P locations booked year over year was directly attributable to the Company's purchase of Dolomite Energy Inc. ("**Dolomite**") in the second quarter of 2015. The Dolomite assets were comprised of 11.0 gross (11.0 net) sections of Slavepoint mineral rights directly adjacent to the Company's Evi/Otter field.

[5] Rate of return is defined as the average NPV10 per well divided by the average capital forecast to be expended per well

The Dolomite acreage has been fully delineated by producing wells however its current well density is 0.6 wells per section in comparison to the Otter area in general which is forecast to be fully developed with an average of approximately 6.0 wells per section. At year end 2015, the Company had booked a total of 24.0 gross (24.0 net) undeveloped 2P locations and 7.0 gross (7.0 net) producing locations to the Dolomite lands. Although the purchase of the Dolomite acreage materially increased the Company's FD&A in 2015, it is anticipated that full cycle (primary drilling plus water flood) FD&A costs associated with this acreage will be in line with the Company's point forward average. Currently there are no wells or lands within this asset base under water flood operations however the Company anticipates that the implementation costs of secondary recovery operations on this land base will be lower than historical projects due to its close proximity to the Company owned and operated infrastructure in the area.

The Company currently has a risked 2P drilling inventory of Slavepoint horizontal light oil wells of 108 net wells with an unrisked 2P drilling inventory of 178 net wells. Virginia Hills quantifies a risked location as locations that are within or directly adjacent to sections that have existing Slavepoint production that meets the Company's economic hurdles while unrisked locations are located greater than one section off-setting from existing economic Slavepoint production. At December 31, 2015 the Company had 21% and 35% of its unrisked and risked inventory, booked within its reserves.

During the year ended December 31, 2015, the Company successfully transformed its Red Earth asset base into a sustainable operation by investing in water flood implementation alongside primary drilling. Virginia Hills' water flood projects have exhibited encouraging economics even at historically low commodity prices with recycle ratios exceeding a 3:1 in 2015. As a result of the success of the Company's water flood projects, it will continue to direct the majority of its efforts and capital to these projects in 2016 and onward. The Company's assets are positioned to grow in a low commodity price environment due to its light oil weighting and moderate decline expectations.

Reserve Based Net Asset Value

($000)	Basic	Diluted
Reserve NPV10	$116,558	$116,558
Undeveloped Land	$3,009	$3,009
Net debt(1)	$108,520	$108,520
Dilution Proceeds	$0	$9,919
Net Present Value	$10,940	$20,859
Share Count (000)	19,724	47,417
Net Present Value per Share	$0.55	$0.44

(1) *See "non-GAAP Measures" advisory. Net debt as of December 31, 2015 is defined as current assets minus current liabilities, plus long term outstanding bank debt.*

(2) *As of December 31, 2015 there were approximately 19,724,000 common shares, 1,773,000 options to purchase common shares and 29,920,000 warrants issued and outstanding.*

FOURTH QUARTER AND YEAR END 2015 - FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended		Year ended	
December 31	**2015**	**2014 (1)**	**2015**	**2014 (1)**
FINANCIAL				
Petroleum and natural gas sales	9,101	12,269	32,839	63,683
Funds flow from operations (2)	2,573	2,579	6,075	20,061
Per share - basic & diluted	0.13	1.19	0.43	8.97
Net loss	18,254	176,473	17,914	175,725
Per share - basic & diluted	0.93	81.24	1.28	80.90
Capital expenditures (3)	237	4,114	10,330	8,745
Net debt (2)(4)	108,520	115,502	108,520	115,502
Common Shares Outstanding (1)				
Weighted average – basic	19,724	2,172	13,984	2,172
Weighted average – diluted	19,724	2,188	13,984	2,188

December 31	Three months ended 2015	2014 [1]	Year ended 2015	2014 [1]
OPERATING				
Number of days	*92*	*92*	*365*	*365*
Production				
Oil and NGL (bbl/d)	1,411	1,831	1,464	1,915
Natural gas (mcf/d)	320	322	309	364
Total production (boe/d)	1,464	1,885	1,515	1,976
Average realized price [5]				
Oil and NGL ($/bbl)	69.90	72.78	61.26	91.06
Natural gas ($/mcf)	1.05	0.16	0.93	0.33
Netback per boe ($)[2]				
Petroleum and natural gas sales	67.57	70.74	59.38	88.31
Royalties	(7.45)	(14.07)	(5.71)	(16.41)
Production and transportation expenses	(27.67)	(30.51)	(27.06)	(28.68)
Field netback [2]	32.45	26.16	26.61	43.22
Realized gain (loss) on derivative financial instruments	-	4.21	-	(1.17)
Operating netback [2]	32.45	30.37	26.61	42.05
Drilling				
Gross wells	-	-	2.0	-
Net wells	-	-	2.0	-

(1) As reported by Pinecrest, predecessor of Virginia Hills. Share and per share amounts for comparative periods reflect the 100:1 share consolidation as though the consolidation took place at the beginning of the earliest period
(2) Non-GAAP measure.
(3) Net debt is defined as current assets minus current liabilities, plus long term outstanding bank debt
(4) Before the effects of derivative financial instruments, but includes gains or losses on fixed price, physical contracts that are not considered derivative instruments.

OPERATIONS UPDATE AND OUTLOOK

Low commodity prices during 2015 presented a challenging business environment for the Canadian oil and gas industry, as the benchmark oil price of WTI decreased 48% from $US93.00 per barrel in fiscal 2014 to average $US48.80 per barrel in 2015. Historically, Virginia Hills' realized commodity prices have tracked the Canadian benchmark oil price due to its corporate production weighting of 97% light oil and natural gas liquids. The fourth quarter and annual 2015 realized average prices decreased to $67.57 per boe and $59.38 per boe, compared to $70.74 per boe and $88.31 per boe realized in the comparable periods of 2014, decreases of 4% and 33%, respectively. However, during 2015, the Company had physical, fixed price commodity contracts in place, which mitigated a decrease in revenues, had the Company been fully exposed to fluctuations in benchmark prices. If the commodity contracts had not been in place, the Company's realized prices would have been $52.94 per boe and $53.38 per boe for the fourth quarter and year ended December 31, 2015. The Company's realized commodity prices are expected to track the benchmark oil prices for 2016, as there are no price risk contracts currently in place. The Company continues to monitor the forward price expectations, and may enter into future contracts to protect the Company's cash flows.

Production volumes for the quarter and year ending December 31, 2015 averaged 1,464 boe/d and 1,515 boe/d, respectively, representing declines of 22% and 23% from 2014 levels. Production for the year was negatively impacted by both the sale of approximately 100 boe/d of net production which occurred in the second quarter and the shut in of 40 boe/d of uneconomic production throughout the year. In addition, the Company experienced a pipeline failure late in the fourth quarter of 2015 which resulted in production of approximately 200 boe/d net being shut in temporarily while clean-up and repair operations took place.

This pipeline break negatively impacted the average fourth quarter daily production by approximately 43 boe/d. Approximately half of the shut in production related to the pipeline failure, came back online by January 1, 2016 (100 boe/d of oil production) with the remaining volumes were brought back on line by March 1 2016. The Company is expecting its first quarter volumes to average between 1,425 boe/d and 1,450 boe/d with production rates exiting the first quarter of 1,525 to 1,575 boe/d (97% light oil and NGLs).

Total operating expenses (which include production and transportation costs) were $3.7 million and $15.0 million for the fourth quarter and year ended December 31, 2015 compared to $5.3 million and $20.7 million in the comparable periods of 2014, representing reductions of 30% and 28% respectively. On a per unit basis, total operating expenses dropped 9% and 6%, respectively in the fourth quarter of 2015 and year to date from 2014 levels to $27.67 per boe and $27.06 per boe, respectively. Year to date expense reductions were offset, in part, by net costs of approximately $0.8 million associated with the clean-up of emulsion pipeline failures and regulatory compliance work in 2015. These costs had a negative impact on operating costs of approximately $1.38 per boe for the year ended December 31, 2015. The Company anticipates having a similar level of expenditures on these items in the first half of 2016, however, as of March 1, 2016, the Company has suspended operations on approximately 16 kilometers of pipeline in the Red Earth area which it has deemed to have unacceptable environmental and regulatory risk. The Company does not anticipate a material negative impact on its cost structure from these pipeline suspensions as none of these pipelines facilitate a material amount of production. In addition the Company has the ability to repair and return these pipelines to operations at marginal cost as future development in the area dictates.

Virginia Hills' field netback for the fourth quarter of 2015, was $32.45 per boe compared to $26.21 per boe for the fourth quarter of 2014. Annual 2015 field netbacks were $26.61 per boe compared to $43.22 per boe in 2014. The decrease in netbacks realized in 2015 due to a decrease in production and commodity prices of 23% and 33%, respectively.

Through the optimization of its extensive Red Earth water flood project area, Virginia Hills believes it is positioned to add additional production and reserves with little incremental capital over the next 12 to 24 month period. These low cost water flood additions are expected to allow the Company to operate a capital program that is below its free cash flow level providing the opportunity for meaningful debt reduction and value creation for its shareholders. The Company maintains a risked and total unrisked undeveloped light oil horizontal 2P drilling inventory in its Red Earth core area of 108 net wells and 176 net wells, respectively, representing over 15 years of potential drilling activity. With this undeveloped light oil drilling inventory and its substantial operated water flood infrastructure foot print in the Red Earth area, Virginia Hills remains uniquely positioned to enter a more meaningful drilling and production growth phase when commodity prices return to more historical levels.

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FORWARD-LOOKING STATEMENTS: This news release contains forward-looking statements. More particularly, this news release contains forward-looking statements concerning: Virginia Hills' corporate decline for 2016; the continued success of the Company's water flood program; increased production from the water flood program; the ability of the Company to decrease drilling and completion costs; type curves in the Slave Point area; the development of the Dolomite acreage in a manner consistent with the Company's acreage; the costs of implementing secondary recovery techniques; the Company's planned capital expenditures; exit production volumes for the first quarter of 2016; environmental and regulatory expenses for 2016; the Company's ability to add reserves during 2016 and 2017; the Company's drilling plans; the timing for the stabilization of commodity prices; average oil prices for 2016 and 2017. In addition, the use of any of the words "guidance", "initial, "scheduled", "can", "will", "prior to", "estimate", "anticipate", "believe", "potential", "should", "unaudited", "forecast", "future", "continue", "may", "expect", "project", and similar expressions are intended to identify forward-looking statements.

The forward-looking statements contained in this news release are based on certain key expectations and assumptions made by the Company, including but not limited to expectations and assumptions concerning: the success of optimization and efficiency improvement projects; the success of the water flood projects and the timing thereof; the availability of capital; the success of future drilling and development activities; the performance of existing wells; the performance of new wells; the timing, cost and ability to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage; the ability to successfully market the Company's petroleum and natural gas products; surface rights access being granted to the Company; the ability of the Company to obtain and retain qualified staff and services in a timely and cost efficient manner; the absence of any material litigation or claims against the Company; the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company has an interest in oil and natural gas properties; and future crude oil, natural gas and NGL prices and currency, exchange and interest rates. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties.

Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: volatility in the demand, supply and market prices for crude oil, natural gas and NGL; volatility in exchange rates; liabilities inherent in petroleum and natural gas operations; uncertainties associated with estimating crude oil, natural gas and NGL reserves and future production levels; increased operating costs incurred by the Company; competition for, among other things, capital and acquisitions of reserves, additional petroleum and natural gas assets and undeveloped lands; incorrect assessments of the value of acquisitions; risks related to the environment and changing environmental laws in relation to the operations by the Company; geological, technical, drilling and completions, processing and handling issues associated with petroleum and natural gas development activities by third parties; claims made or legal actions brought or realized against the Company, its properties or assets; a failure by the Company to hire or retain key personnel; general economic, market and business conditions; and changes in tax or environmental laws or royalty or incentive programs relating to the oil and natural gas industry.

The forward-looking statements contained in this news release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

NON-GAAP MEASURES: This news release contains the terms "funds flow from operations", "net debt", "field netback" and "operating netback" which do not have a standardized meaning prescribed by Canadian generally accepted accounting principles ("**GAAP**") and therefore may not be comparable with the calculation of similar measures by other companies. Management uses funds flow from operations to analyze operating performance and leverage. Management believes "net debt" is a useful supplemental measure of the total amount of current and long-term debt of the Company. Management believes "field netback" and "operating netback" are useful supplemental measures of the amount of revenues received after royalties and production and transportation costs, and the amount of revenues received after royalties, operating, transportation costs and realized gain (loss) on derivatives. Additional information relating to certain of these non-GAAP measures, including the reconciliation between funds flow from operations and cash flow from operating activities can be found in the MD&A.

BOE ADVISORY: To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

OIL AND GAS ADVISORY: The reserves estimates contained in this press release represent our gross reserves as at December 31, 2015 and are defined under NI 51-101, as our interest before deduction of royalties and without including any of our royalty interests. It should not be assumed that the present worth of estimated future net revenues presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis. Estimated values of future net revenue disclosed herein do not represent fair market value.

This news release contains metrics commonly used in the oil and natural gas industry, such as “recycle ratio”, “F&D costs”, “FD&A”, “operating netbacks”, "rate of return", "reserves replacement ratio" and “RLI”. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

DRILLING LOCATIONS: This press release discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the Sproule Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Corporation's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Of the gross drilling locations of the Company identified herein,28 are proved locations, 10 are probable locations and are 138 unbooked locations (70 risked and 138 unrisked). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

INITIAL PRODUCTION RATES: Any references in this news release to initial production rates or flow back production results are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company.

TYPE CURVE ADVISORY: References in this news release to production type curves and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinatives of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Virginia Hills. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, Virginia Hills cautions that the test results should be considered preliminary.

FUTURE ORIENTED FINANCIAL INFORMATION: This news release, in particular the information in respect of anticipated production volumes, may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable Canadian securities laws. The FOFI has been prepared by management of Virginia Hills to provide an outlook of Virginia Hills' anticipated activities and results. The FOFI has been prepared based on a number of assumptions, including the assumptions discussed under the heading "Forward Looking Statements" and assumptions with respect to production rates, drilling results, and commodity prices. The actual results of operations of the Virginia Hills and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. Virginia Hills and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

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Neither the TSX Venture Exchange nor its Regulation Services Provider (as that term is defined in the policies of the TSX Venture Exchange) accepts responsibility for the adequacy or accuracy of this news release.