TENTH AVENUE PETROLEUM CORP.
BUSINESS ACQUISITION REPORT
FORM 51-102F4

ITEM 1 IDENTITY OF COMPANY

1.1 Name and Address of Company

Tenth Avenue Petroleum Corp. ("**TAPC**" or the "**Corporation**")
203, 221 – 10th Avenue SE
Calgary, Alberta T2G 0V9

1.2 Executive Officer

For further information concerning the acquisition described in this business acquisition report (the "**BA Report**"), contact Gregory J. Leia, the Chief Executive Officer of the Corporation, at 403-265-4122.

ITEM 2 DETAILS OF ACQUISITION

2.1 Nature of Business Acquired

On July 31, 2017, the Corporation completed the purchase of certain oil and gas producing assets (the "**Acquisition**") in the Waskahigan area of Alberta (the "**Waskahigan Assets**"). The present value before tax of the Waskahigan Assets as prepared by GLJ Petroleum Consultants Ltd. ("**GJL Consultants**") for proved producing assets is $2,114,000 with a discount rate of 10% and $3,503,000 for total proved plus probable with a discount rate of 10% effective December 31, 2016. The Alberta Energy Regulator Licensee Liability Rating ("**AER LLR**")(AER deemed assets value/deemed liabilities based on 100% production from licensed wells) was approximately 4.5 as of December 31, 2016.

The Acquisition included 8 wells and associated production of approximately 1,800 mcf/day and 20 barrels of natural gas liquids per day. TAPC acquired mineral rights to 22 gross sections (15.19 net sections) (14,080 gross acres 9,726 net acres). The majority of the mineral rights are above Bullhead Bullhead Group formation (primarily Dunvegan, Notikewin and Gething formation) near Fox Creek, Alberta. The Corporation has identified drilling locations on the lands acquired and has plans to increase production upon natural gas prices improving. The Corporation views the Acquisition as strategic. It has become the core land base, greatly increasing the Corporations' natural gas production and reserves. A discussion of the Waskahigan Assets, together with reserves data and other oil and gas information in respect to the Waskahigan Assets is set forth in Schedule "A" to this BA Report.

2.2 Date of Acquisition

The Acquisition closed on July 31, 2017.

2.3 Consideration

The price was $1,400,000 plus $14,000 in GST and assumption of the abandonment and remediation liabilities associated with the oil and gas properties. The sum of $290,000 was allocated to intangibles and $1,110,000 to mineral rights. The Acquisition had an effective date of May 1, 2017. TAPC made a cash payment to the vendor of $1,326,593 (cash to close based on interim statement of adjustments) on July 31, 2017 which included $41,928 in natural gas liquids inventory, $14,000 in GST on tangibles, $9,527 in interest to the vendor, $6,230 for PNG rights, $6,898 for surface rentals and a credit of $151,991 for revenue from May 1, 2017 to July 31, 2017. The carrying cost shown in TAPC's third quarter financial statements was $1,589,760 reflecting the payment to the vendor (net of GST), depreciation, depletion and $176,245 as the quantum of the abandonment and remediation liability payable over time as provided in the GLJ Report discounted to present day multiplied by the working interest of TAPC. The GLJ Report assumed an abandonment and remediation cost of $90,000 per well included in the GLJ Report. The acquisition cost a shown in TAPC's third quarter financial statements did not the abandonment and/or remediation costs of certain wells which were abandoned and were in process of being remediated but had not received clearance certificates from the AER. No value was attributed to future exploration value because of the difference between the sales price and sales price forecasts used in the GLJ Report and the sales price and sales price forecasts for natural gas at closing.

Concurrent with closing, TAPC entered into a Loan and Participation Agreement with Smoky Oil & Gas Corp ("**Smoky**") and Batoche Oil & Gas Exploration Ltd. ("**Batoche**"). Smoky is 65% owned by family members of Gregory J. Leia. Batoche is owned by Gregory J. Leia. Gregory J. Leia is an officer and director of TAPC and its largest shareholder. Pursuant to the terms of the Loan and Participation Agreement ("**LPA**"), Smoky lent TAPC the sum of $1,326,593 to make the Acquisition. The interest rate on the loan principal is 6% per annum. All obligations owing are secured by a general security agreement charging all of the assets of TAPC. Subject to an agreed upon general and administrative expense payment, Smoky shall be entitled to all net cash flow from the Waskahigan Assets until the loan is repaid. The LPA provided that while loans are outstanding, TAPC shall be restricted to charging general and administrative costs to a maximum of $75,000 per year for administration of the Waskahigan Assets and charging general and administrative costs to a maximum of $75,000 per year for administration of the Waskahigan Participation Assets (as defined below). The LPA was amended on September 30, 2017, to provide that TAPC shall be entitled to all net cash flow from operations until December 31, 2017.

TAPC has agreed to farmout to Batoche the Waskahigan Assets (other than existing wells and applicable spacing units)("**Waskahigan Participation Assets**") on the terms and conditions set out in the Batoche Farmout Agreement. If Batoche defaults under the terms of the Batoche Farmout Agreement, and if TAPC is unable to farmout to a third party, then TAPC has agreed to farmout the Waskahigan Participation Assets to Smoky (if Smoky chooses to farmin) on terms and conditions equivalent to the farmout terms set out in Batoche Farmout Agreement. The Batoche Farmout Agreement contains a 3 well requirement to earn a 70% working interest in all Waskahigan Participation Asset mineral rights. The Batoche Farmout Agreement requires Batoche to be drill ready (Well #1) by June 30, 2019. Terms are: Batoche is to pay 100% of all costs to drill, complete and equip Well #1 to earn 70% in spacing unit associated with Well #1 subject to payout. The working interest participants are required to pay their proportionate share of Well #2 and Well #3. If Batoche drills Well #2, Batoche will earn 70% in the spacing unit associated with Well #2. If Batoche drills Well #3, Batoche will earn 70% working interest in all Waskahigan Participation Assets and any other lands acquired by TAPC in Waskahigan area. Assuming Batoche earns 70% working interest in the Waskahigan Participation Assets, TAPC will have a 6% working interest and Smoky will have a 24% working interest in the 3 wells and future developments.

Pursuant to the LPA, as additional consideration, Smoky shall be entitled to receive: (a) 80% of net cash flow from the Waskahigan Assets (less agreed general and administrative expenses) from January 1, 2018 until December 31, 2021 (subject to farmout rights); (b) 80% of net sale proceeds of Waskahigan Assets (subject to farmout rights); (c) right to compel TAPC to buy Smoky's right to 80% of the net cash flow from the Waskahigan Assets (subject to farmout rights) for 2.5 times net cash flow; and (d) right to compel TAPC to buy Smoky's right to 24% of the net cash flow from the Waskahigan Participation Assets (subject to farmout rights) for 2.5 times net cash flow from the Waskahigan Participation Assets. TAPC shall have the right to: (a) right to compel Smoky to sell its right to 80% of the net cash flow from the Waskahigan Assets (subject to farmout rights) for 2.5 times net cash flow; and (d) right to compel Smoky to sell its right to 24% of the net cash flow from the Waskahigan Participation Assets for 2.5 times net cash flow from the Waskahigan Participation Assets.

2.4 Effect on Financial Position

The Corporation borrowed one hundred (100%) percent of the acquisition cost so there was no effect on the existing assets or financial position of the Corporation. The effect on the financial position of the Corporation will depend to a great extent on the net revenue generated from the sale of petroleum products (primarily natural gas). An indicator of the effect on financial position is the historical operating income generated from the Waskahigan Assets.

Alberta securities laws require TAPC to include audited operation statements for the Waskahigan Assets for the fiscal year ended December 31, 2016. See Schedule "B". TAPC is also required to include unaudited statements for the Waskahigan assets for the fiscal period ended December 31, 2015 as well as unaudited comparative statements for the 6 month period ended June 30, 2016 and June 30, 2017.

Caution should be used in relying on the statements as an accurate indicator of future operating income for TAPC for the following reasons:

First: The price that TAPC will receive for natural gas will differ from the price the vendor reported to TAPC for the purpose of the audit because the vendor blended the price for all natural gas sales company wide. It is believed that the vendor had hedged its production at Alliance pipeline Chicago City Gate pricing and sold natural gas at prices higher than AECO prices (see Schedule "A" for definition of AECO prices). TAPC was not provided with sales information from the vendor or the auditor and therefore TAPC has had to extrapolate and speculate. If TAPC has extrapolated and estimated from vendor information, TAPC has specified that it has done so in the text of this document.

Second: The vendor may have taken the production in kind and sold the natural gas through its own marketer. Because TAPC does not have sufficient firm service on the NOVA Pipeline (see definitions in Schedule "A"), TAPC will likely be required to sell its gas to a midstream company (Paramount, Firenze and CNRL) who could take the benefit of the spread between AECO and hedged pricing.

Third: TCPL has constricted NOVA Pipeline access in September, October and November 2017 due to construction and other upgrades. The AECO price has been artificially and negatively affected by construction and the limited takeaway pipeline capacity in Western Canada. The Corporation has shut in its wells from September 25, 2017 to the end of November 2017. TAPC has recommenced production from 1 Waskahigan well and 1 Crossfield well in December 2017 which are producing approximately 1,050 mcf/d. TAPC recommenced production from an additional Waskahigan well in mid January 2018 and the well has produced approx. 750 mcf/d (net).

Fourth: The Acquisition increased the Corporation's production by approximately 1,800 mcf/day and 20 b/NGL/day. The 15-24-63-24-W5th well produced approximately 150 mcf/d of natural gas (net to TAPC - 75% WI). The gas from the 15-24-63-24-W5th well was delivered to the Waskahigan gas processing plant of CNRL. The vendor assigned its mineral rights, wells, pipelines and three operating contracts to TAPC (well contracting, effluent handling and transportation, compression and processing). CNRL will not recognize the assignment. As such, production of the 15-24-63-24-W5th well will likely be shut in until the assignment issue can be resolved.

Schedule "B" requires further discussion with respect to the timing and disclosure of certain line items:

		Six months ended June 30			Years ended December 31	
		2017 *(Unaudited)*	2016 *(Unaudited)*		2016 *(Audited)*	2015 *(Unaudited)*
Revenue						
	Revenue (Note 1)	$ 1,074	$ 819		$ 1,846	$ 2,452
	Royalties	(130)	34		(22)	5
	Total Revenue	944	853		1,824	2,457
Expense						
	Production	475	558		1,053	1,197
	Transportation cost	123	187		323	303
	Subtotal before prior period charges	346	108		448	957
	Prior Year Equalization Payments (Note 2)	270	0		0	0
	Operating Income	**$ 76**	**$ 108**		**$ 448**	**$ 957**

Note 1: The pricing and gross revenue was based on an audit of the vendors books (and may have included a blended rate of hedged pricing (above AECO and AECO pricing). The average AECO 5A price was $2.02Cdn/GJ for 2016 and $2.59 Cdn/GJ for the first six months of 2017 (estimates based on pricing set out below). The sales figure are a combination of natural gas, liquids and oil. It is estimated that the vendors average sale price was $3.05Cdn/mcf for the first 6 months of 2017 and $2.56Cdn/mcf for 2016.

Note 2: The Paramount Compression Agreement dated December 1, 2007 between the vendor and Paramount provided that the vendor would be responsible for a base charge of (a) booster and sales compression of $5.28/e3m3; and (b) fixed and operating compression of $7.39/e3m3; and (c) an equalization through put charge based on annual operating charges over annual throughput. The vendors throughput represented approximately 75% of the throughput. The Paramount Processing Agreement dated December 1, 2007 between the vendor and Paramount provided that the vendor would be responsible for a base charge of : (a) fixed $11.57/e3m3; (b) operating charge of approx. $15/e3m3; and (c) an equalization through put charge based on annual operating charges over annual throughput. The charges have remained the same since May 2012 and are not competitive with competitive compression and processing charges assuming pipeline access. On February 2017, the vendor received invoices from Paramount for 4 prior years : (a) Invoice 105454 - 2013 - $18,908; (b) Invoice 105497 - 2014 - $72,465; (c) Invoice # 105508 - 2015 - $356,318; and (d) Invoice # 105699 - 2016 credit of $23,239. The vendor booked a $270,000 charge against the first 6 months operating income for the prior period equalization and throughput charges. It is uncertain what those amounts will be in 2017. On October 1, 2017, TAPC terminated the Paramount Compression Agreement and Paramount Processing Agreement. Effective January 1, 2018, TAPC renegotiated a Paramount Gas Handling Agreement: (a) at competitive compression and processing charges; and (b) without the equalization/throughput requirement.

The table below sets out the estimates sales prices for the vendor of the Waskahigan Assets for the stated period.

(have not been verified)		Six months ended June 30, 2017	Years ended December 31 2016	2015
			Extrapolated and Estimated	
	Volume of gas (mcf)	295,857	598,562	666,743
	Average price /mcf	$3.05	$2.56	$3.15
	Volume of oil and NGL's (bbl)	3,750	6,235	6,551
	Average Price/bbl	$44.00	$48.00	$52.00

The monthly natural gas prices were as follows:

	AECO 5A	AECO 7A	AECO 5A	AECO 7A	Chicago City Gate NGI
	Cdn/GJ	Cdn/GJ	$US/MMBtu	$US/MMBtu	$US/MMBtu
January 2016	$2.2496	$2.1963	$1.6734	$1.6589	$2.5700
February 2016	$1.6899	$2.2284	$1.2918	$1.6787	$2.3200
March 2016	$1.2671	$1.5761	$1.0113	$1.2403	$1.8500
April 2016	$1.0388	$1.2244	$0.8552	$0.9902	$1.8800
May 2016	$1.1780	$1.0412	$0.9597	$0.8754	$2.0400
June 2016	$1.7642	$1.2809	$1.4427	$1.0324	$1.9400
July 2016	$2.2570	$1.8475	$1.8236	$1.5054	$2.8000
August 2016	$1.8299	$2.1947	$1.4839	$1.7691	$2.6700
September 2016	$2.5159	$2.2152	$2.0248	$1.7833	$2.8100
October 2016	$2.9424	$2.4676	$2.3420	$1.9818	$2.9600
November 2016	$2.6058	$2.8392	$2.0447	$2.2388	$2.8000
December 2016	$3.2412	$2.6966	$2.5635	$2.1340	$3.2500
January 2017	$2.7615	$3.3268	$2.2055	$2.6121	$4.1600
February 2017	$2.4059	$2.7047	$1.9379	$2.1802	$3.4100
March 2017	$2.4946	$2.3349	$1.9652	$1.8459	$2.6200
April 2017	$2.6779	$2.4646	$2.1034	$1.9422	$3.0100
May 2017	$2.8407	$2.6168	$2.2037	$2.0221	$2.9200
June 2017	$2.4002	$2.8050	$1.9014	$2.1947	$3.0900
July 2017	$1.5504	$2.3029	$1.2841	$1.8691	$2.8750
August 2017	$1.6519	$2.0320	$1.6519	$1.7095	$2.8300
September 2017	$0.9294	$1.4604	$0.7995	$1.2451	$2.7900
October 2017	$0.7031	$1.4850	$0.5855	$1.2528	$2.8200
November 2017	$2.1893	$2.0416	$0.7704	$1.8101	$1.6710
December 2017	$1.9203	$2.0365	$0.4986	$1.5913	$1.6910

The combination of the producing reserves and the potential additions from the development upside identified with respect to the Waskahigan Assets, will significantly increase the Corporation's reserve base. Management has identified numerous opportunities to enhance the value of the Waskahigan Assets. With an expanded inventory of both exploration and development locations, the Corporation is well positioned for additional growth potential through a risk balanced capital program.

The major constraints are: (a) historically high spread between NYMEX and AECO; (b) NOVA Pipeline takeaway capacity; and (c) access to reasonably prices compression and processing charges. The positives are: (a) NYMEX

(Henry Hub) price has remained at 2016 levels; (b) TCPL is in process of doubling the NOVA Pipeline takeaway capacity by 2020; (c) Alliance is increasing its takeaway capacity by 50% by 2020; and (d) with the development of the Duvernay formation by Encana, Chevron, Murphy and Shell), midstream companies(Keyera and Pembina) have agreed to spend significant capital to increase the area capacity within next two years. It is expected that within 2 years lower compression and processing costs will be available because of the excess midstream capacity in the area.

2.5 Prior Valuations

The vendor obtained an independent reserve evaluation report prepared by GLJ Consultants dated February 29, 2017 with an effective date of December 31, 2016. The report was prepared in accordance with N I51-101 using GLJ Consultants forecast prices and costs at December 31, 2016 in Canadian dollars.

The Corporation engaged GLJ Consultants to prepared a report for the Corporation using the same information as the vendor. The report was dated July 27 2017 and effective December 31, 2017. For information regarding the undiscounted value and the present value, discounted at 5%, 10% and 15%, of the estimated future net revenue of the Waskahigan Assets, see Item 2.1 and in particular, the table entitled "Summary of Net Present Values of Future Net Revenue - Before Income Taxes - Forecast Prices as of December 31, 2016".

The reserves attributable to the Waskahigan Assets acquired in the Acquisition are further reflected in the independent reserve evaluation report prepared by GLJ Consultants filed on www.sedar.com.

2.6 Parties to Transaction

No informed person, associate or affiliate of the Corporation, as those terms are defined under applicable securities legislation, was a party to the Acquisition.

2.7 Date of Report

This BA Report is dated February 19, 2018.

ITEM 3 FINANCIAL STATEMENTS

Pursuant to Part 8 of NI 51-102 — *Continuous Disclosure Obligations* ("51-102") the operating statements of the Waskahigan Assets for the fiscal years ended December 31, 2016 (audited) and December 31, 2015 (unaudited) are attached as Schedule "B" to this BA Report.

Cautionary Statements

This BA Report contains forward-looking statements and information ("**forward-looking statements**") within the meaning of applicable securities laws. Although the Corporation believes that the expectations reflected in its forward-looking statements are reasonable, such statements have been based upon currently available information to the Corporation. Such statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause actual results or events to differ materially from those stated, anticipated or implied in forward-looking statements. Risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; political and terrorism related risks; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of resource and reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity prices, price and exchange rate fluctuation and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Readers are cautioned to not place undue reliance on forward-looking statements. The statements in this BA Report are made as of the date of this BA Report and, except as required by applicable law, the Corporation does not undertake any obligation to publicly update or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement. The Corporation undertakes no obligation to comment on analyses, expectations or statements made by third-parties in respect of the Corporation or its financial or operating results or its securities.

Schedule "A"

Glossary, Terms and Abbreviations

In this BA Report, the defined terms set forth below have the following meanings:

"**AECO**" refers to the daily index price, which is often quoted in the media, is commonly referred to as the "NGX Daily Index", "AECO/NIT 2A or 5A" average price. Natural gas rates for Alberta's consumers are based on gas prices established through the Natural Gas Exchange (NGX) electronic trading platform. The NGX platform brings together sellers who "offer" natural gas for sale and buyers who "bid" for natural gas purchases. Contract terms may be for the day, the weekend, rest of month or future months' deliveries. The trading platform is very liquid and typically sells over twice the amount of natural gas that is actually being produced in Alberta every day. The NGX trading platform is activated very early each day, with gas traders transacting numerous bids and offers every minute on various product offerings. The most frequently traded product is gas supplies priced at "Daily Index". Daily Index is the average price published by NGX for all transactions for that day and does not reflect future prices. Another highly traded product on NGX is the "AECO/NIT 7A" Monthly Index price. Each day, traders buy and sell natural gas for next month's deliveries. At the end of the month, NGX determines the monthly index price for the next month using the weighted average price of all transactions contracted for that month.

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**CNRL**" Canadian Natural Resources Northern Alberta Partnership;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;
"Company Interest" means the Corporation's total working interest share before deduction of royalties and including any royalty interests;

"**Current Production**" means average daily gross production from the Acquired Assets for the twelve month period ended December 31, 2016;

"**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;

"**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 certainly;

"**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;

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

"**Encana**" means Encana Corporation;

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

"**Firenze**" means Firenze Energy Ltd.;

"**firm service**" means a service agreement with Nova Gas Transmission Ltd for rate Schedule FT-R service;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**GLJ Consultants**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ Consultants dated July 27, 2017 on the Waskahigan Assets as of December 31, 2016 using their December 31, 2016 price deck

"**gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

(b) in relation to wells, the total number of wells in which an entity has an interest; and

(c) in relation to properties, the total area of properties in which an entity has an interest;

"**Keyera**" means Keyera Corp;

"**net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating an entity's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which an entity has an interest multiplied by the working interest owned by it;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

"**NOVA Pipeline**" the pipeline operated by NOVA Gas Transmission Ltd. in Waskahigan area;

"**NYMEX**" Prices are based on delivery at the Henry Hub in Louisiana. Official daily closing prices at 2:30 p.m. from the trading floor of the New York Mercantile Exchange (NYMEX) for a specific delivery month. The natural gas liquids (NGPL) composite price is derived from daily Bloomberg spot price data for natural gas liquids at Mont Belvieu, Texas, weighted by gas processing plant production volumes of each product as reported on Form EIA-816

"**Paramount**" means Paramount Resources Ltd.;

"**PDP Reserves**" means proved developed producing reserves;

"**Pembina**" means Pembina Pipeline Corporation;

"**P+P Reserves**" means Proved Reserves plus Probable Reserves;

"**Probable Reserves**" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated P+P Reserves;

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

"**resource play**" refers to drilling programs targeted at regionally distributed crude oil or natural gas accumulations; successful exploitation of these reservoirs is dependent upon technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas;

"**Reserve Life Index**" or "**RLI**" is calculated by dividing year-end reserves by expected Current Production;

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"**ROFR**" means a right of first refusal;

"**ROFR Properties**" means those producing and non-producing oil and natural gas properties and related assets acquired from Advantage pursuant to the Acquisition, which properties are subject to ROFRs;

"**TCPL**" means Trans Canada Pipelines Ltd. (parent of NOVA Gas Transmission Ltd.);

"**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) to which they are assigned.

Abbreviations

bbl	Barrel	**MMbtu**	Millions of British thermal units
Mbbl	Thousands of barrels	**NGLs**	Natural gas liquids
BOE	Barrel of oil equivalent (6 Mcf = 1 Bbl)	**Mcf**	Thousand cubic feet
Mboe	Thousand barrels of oil equivalent	**MMcf**	Million cubic feet
GJ	Gigajoule		

Conversion

The preceding table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).
1 GJ = 0.9407 MMBTu
1 mcf = 1.028 MMBTu

Currency

In this BA Report, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

Summary of Reserves Data and other Oil and Gas Information for the Waskahigan Assets

The GLJ Report was prepared by GLJ Consultants in respect to the Waskahigan Assets. The GLJ Report has been prepared in accordance with NI 51-101 using GLJ Consultant's forecast prices and costs at December 31, 2016 in Canadian dollars.

The future net revenues presented in the GLJ Report may not necessarily represent the fair market value of the reserves estimates. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of 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 liquids and natural gas reserves may be greater than or less than the estimates provided herein.

BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The reserves relating to the Waskahigan Assets are summarized below.

Summary of Remaining Reserves
Forecast Prices and Costs as of December 31, 2016

	Heavy Gross (Mbbl)	Oil Net (Mbbl)	Natural Gross (MMcf)	Gas Net (MMcf)	Natural Gas Gross (Mbbl)	LiquidsNet (Mbbl)	Total Gross (Mboe)	Net (Mboe)
Proved								
Developed Producing	--	--	3,304	-	26	-	583	470
Developed Non-Producing	--	--	701	-	6	-	122	122
Undeveloped	--	--	1,183	-	8	-	206	206
Total Proved	--	2.5	5,206	-	41	-		799
Probable	--	1.3	-	-	12	-		
Total Proved Plus Probable	--	3.8	6,775	-	53	-	1,186	1,040

Summary of Net Present Values of Future Net Revenue

Forecast Prices and Costs as of December 31, 2016

	Before Income Taxes Discounted at (%/year)			
(M$)	0%	5%	10%	15%
Proved				
Developed Producing	2,735	2,397	2,114	1,886
Developed Non-Producing	615	543	471	402
Undeveloped	415	158	4	-82
Total Proved	**3,764**	**3,097**	**2,588**	**2,213**
Probable				
Total Proved Plus Probable	**5,907**	**4,475**	**3,503**	**2,86**

GLJ Consultant's price forecast utilized in the GLJ Report is summarized below.

Summary of Pricing and Inflation Rate Assumptions Forecast Prices and Costs
as of December 31, 2016

Year	WTI Cushing Oklahoma (SUS/bbl)	Light Sweet Crude Oil at Edmonton 40° API	Medium Bow River Crude Oil 21° API ($Cdn/	Hardisty Heavy 12° API ($Cdn/bbl)	Natural Gas AECO-C Spot ($Cdn/MMBt	Natural Gas Liquids Edmonton Cond ($Cdn/bbl)	Natural Gas Liquids Edmonton Propane ($Cdn/bbl)	Natural Gas Liquids Edmonton Butane ($Cdn/bbl)	Inflation Rate [1] %/Year	Exchange Rate [2] (SUS/SCdn)
2016	43.93	52.95	39.71	32.66	2.19	N/A	13.03	34.36	1.5	7.55
2017	55.00	69.33	54.02	46.69	3.46	11.15	28.43	49.92	2.0	0.750
2018	57.84	72.26	57.52	50.40	3.10	9.92	26.74	54.19	2.0	0.775
2019	61.51	75.00	62.02	55.03	3.27	10.52	26.25	56.25	2.0	0.800
2020	63.14	76.36	63.76	56.96	3.49	11.27	26.73	57.27	2.0	0.825
2021	65.59	78.82	66.68	59.95	3.67	11.87	27.59	59.12	2.0	0.850

Notes:
1. Inflation rates used for forecasting prices and costs.
2. Exchange rates used to generate the benchmark reference prices in this table.

Material Assumptions in the GLJ Report

The effective date of the GLJ Report is December 31, 2016. The reserves estimates presented in the GLJ Report were based on the operating and economic conditions and development status as of that date except for changes planned for the immediate future or in the process of implementation. The basic information employed in the preparation of this report was obtained from the property files, public sources and from GLJ Consultant's own 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 Canadian properties.

The net present values of the crude oil, natural gas and natural gas products reserves were obtained by employing future production and revenue analyses. The future crude oil production was generally predicated on the anticipated performance characteristics of the individual wells and reservoirs in question.

The Corporation's share of future crude oil revenue was derived by employing the Corporation's share of production and the forecast reference crude oil price less the historical quality and transportation price differential for each respective field.

Reserve Disclosure

There are numerous uncertainties inherent in estimating quantities of reserves. The reserve information set out herein 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 herein.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. There is a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. There is a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

References to oil, gas, natural gas liquids, reserves (gross, net, proved, probable, possible, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, operating costs, development costs, future net revenue and future income tax expenses shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in NI 51-101, Companion Policy 51- 101CP and all forms referenced therein.

Description of Property Acquired

Pursuant to the Acquisition, TAPC acquired:

- 100% of existing gathering systems associated with the Waskahigan Assets including pipelines, flow lines, satellite facilities and meters;
- _85% of the production from the Waskahigan Assets; and
- High working interest in 22 sections of land in the Waskahigan area, which is located northwest of the city of Edmonton, Alberta

TAPC's land base in the Waskahigan area is productive primarily from: (a) Gething formation; (b) Dunvegan; and (c) Notikewan Member of the Spirit River formation. Subject to production restrictions it is possible to concurrently produce form all three zones.

The Gething formation is a stratigraphic unit of the Lower Cretaceous age in the Western Canadian Sedimentary Basin. The formation consists of alternating units of sandstone and carbonaceous shale or mudstone. with some coal seams and conglomerate beds. The Gething is the uppermost unit of the Bullhead group and overlies the Cademin formation. The sediments are mostly non-marine origin, deposited deltaic and coastal plain settings. The Dunvegan formation is a stratigraphic unit of Cenomanian age in the Western Canadian Sedimentary Basin. The Dunvegan formation is composed of marine and deltaic sandstone with thin shale interbresds. The Spirit River formation is a stratigraphic unit of middle Albian age in the Western Canadian Sedimentary Basin. The Spirit River formation consists of three members (from top to bottom: Notikewan, Fahler and the Wilrich member. The Notikeiwan consists of fine to medium aragillaceous, sandstone, dark shale and ironstone.

Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2016 in which TAPC has a working interest.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	0	0	0	0	1	1.0	12	0.85

Properties with no Attributed Reserves

The following table sets out the developed and undeveloped land holdings forming part of the Acquired Assets as at December 31, 2016.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	480	400	13,600	9,326		9,726

In the year ended December 31, 2016, rights to explore, develop and exploit 9,726 net acres of undeveloped land expired. None of undeveloped land holdings will expire by December 31, 2017. A portion of TAPC's 2017 exploitation and development program may result in extending or eliminating such potential expirations. TAPC closely monitors land expirations as compared to its development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities.

Forward Contracts – Access to Facilities and Pipelines

TAPC's operational results and financial condition will be dependent upon the prices received for oil and natural gas production and access to facilities and pipelines. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors. Supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on the Corporation's financial condition. TAPC does not own its own processing facilities.

It processes its gas through three facilities which are located on the NOVA Pipeline. The processing plants are: (a) Wooster meter station operated by Firenze; (b) Maddenville meter station operated by Paramount; and (c) Waskahigan meter station operated by CNRL.

TAPC ability to implement a hedging policy using, amongst others, costless collars and fixed price is limited by the agreements it has with processing plants and access to the NOVA Pipeline. All of TAPC's natural gas is transported on the NOVA Pipeline. As of December 31, 2017, TAPC processes approximately 30 e3m^3/d through the Firenze plant located on the Wooster meter station. TAPC has firm service for 7 e3m3/d. TAPC has temporarily assigned 15 e3m3/d of firm service from Maddenville to Wooster. The balance of the 8 e3m^3/d, Firenze sells the gas and pays TAPC the AECO 5A price less adjustment (processing) for the gas. TAPC was processing approximately 22 e3m^3/d through the Simonette Plant/Deep Valley of Paramount which is located at the Maddenville meter station until TAPC shut in its production at the end of September 2017. TAPC has firm service for 15 e3m^3/day and relied on Paramount to sell the 7 e3m^3/d gas and pay TAPC AECO 5A pricing. TAPC was processing approximately 5 e3m^3/day through the Waskahigan plant of CNRL at the Waskahigan meter station until August 31, 2017 when it shut in its production. TAPC does not have term service and relies on CNRL to sell its gas and CNRL pays TAPC the AECO 5A price.

Any gas sold by Firenze, Paramount and CNRL cannot be hedged. TAPC will be seeking to acquire firm service so it can hedge its production at prices higher than AECO 5A. These hedging activities could expose the Corporation to losses or gains. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Corporation's exposure to these entities.

Additional Information Concerning Abandonment and Reclamation Costs

TAPC estimates the costs to abandon and reclaim all its non-producing and producing wells, gas plants, pipelines, batteries, and other facilities. No estimate of salvage value is netted against the estimated cost. The Corporation's model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are based on internal estimates. Each well and facility are assigned an average cost for abandonment and reclamation over a 60 year period. Timing of expenditures are based on budgets and estimates of such annual activities. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of the Corporation's associated reserves and continue beyond the reserve life under the assumption that decommissioning of plant/facilities are generally mobile assets with a long useful life.

TAPC estimates that it will incur reclamation and abandonment costs. Discounted estimates are provided as part of the GLJ Report. . TAPC does not expect to incur any abandonment and reclamation costs over the next three years.

Tax Horizon

TAPC had approximately $15 million of tax pools available, primarily comprised of net operating losses, Canadian Oil and Gas Property Expense and Capital Cost Allowance deductions. It is expected, based upon current legislation, the projections contained in the GJL Report and various other assumptions that no cash income taxes are to be paid by the Corporation prior to 2016. A higher level of capital expenditures than those contained in the GJL Report, or further additional acquisitions, could further extend the estimated tax horizon.

Capital Expenditures

The following tables summarize capital expenditures (excluding capitalized general and administrative and other expenses) related to activities attributable to the Acquired Assets for the year ended December 31, 2016:

($ thousands)	December 31, 2016
Land and seismic	Nil
Drilling, completions and workovers	Nil
Well equipping and facilities	Nil
Total capital expenditures	Nil

In addition, there were no capital expenditures on the Acquired Assets related to exploration activities for the years ended December 31, 2016 or December 31, 2017.

Exploration and Development Activities

There were no exploration or development activities on the acquired assets for the year ended December 31, 2016 or 2017.

OPERATING STATEMENT FOR THE WASKAHIGAN ASSETS
FOR THE YEAR ENDED DECEMBER 31, 2016 (AUDITED)
AND DECEMBER 31, 2015 (UNAUDITED)

KPMG

KPMG LLP
205 5th Avenue SW
Suite 3100
Calgary AB
T2P 4B9
Telephone (403) 691-8000
Fax (403) 691-8008
www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Directors of Tenth Avenue Petroleum Corp.

We have audited the accompanying operating statement containing revenue, royalties, production costs, transportation and operating income of certain petroleum and natural gas properties in the Waskahigan area of the Province of Alberta for the year ended December 31, 2016 and notes comprising a summary of significant accounting policies and other explanatory information (together "the operating statement".)

Management's Responsibility for the Operating Statement

Management is responsible for the preparation and fair presentation of this operating statement in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, *Acceptable Accounting Principles and Auditing Standards*, for an operating statement of an acquired oil and gas property and for such internal control as management determines is necessary to enable the preparation of the operating statement that is free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the operating statement based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the operating statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the operating statement. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the operating statement, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the operating statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the operating statement.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the operating statement of certain oil and gas properties in the Waskahigan area of the Province of Alberta for the year ended December 31, 2016 is prepared, in all material respects, in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, *Acceptable Accounting Principles and Auditing Standards*, for an operating statement of an acquired oil and gas property.

KPMG LLP

Chartered Professional Accountants

October 13, 2017
Calgary, Canada

Tenth Avenue Petroleum Corp.

Operating Statement Containing Revenue, Royalties, Production Costs Transportation Costs, and Operating Income

For the six months ended June 30, 2017 and 2016 (unaudited) and the years ended December 31, 2016 (audited) and 2015 (unaudited)

($ Canadian *thousands*)

		Six months ended June 30,		Years ended December 31,	
		2017	**2016**	**2016**	**2015**
		(unaudited)	*(unaudited)*	*(audited)*	*(unaudited)*
Revenue					
	Revenue	$ 1,074	$ 944	$ 1,846	$ 2,452
	Royalties	(130)	(116)	(22)	5
	Total Revenue	944	828	1,824	2,457
Expense					
	Production costs	745	561	1,031	1,197
	Transportation costs	123	194	323	303
	Operating Income	**$ 76**	**$ 73**	**$ 470**	**$ 957**

See accompanying notes to the operating statement.

Tenth Avenue Petroleum Corp.

Notes to Operating Statement Containing Revenue, Royalties, Production Costs, Transportation Costs, and Operating Income

For the six months ended June 30, 2017 and 2016 (unaudited) and the years ended December 31, 2016 (audited) and 2015 (unaudited)

1. BASIS OF PRESENTATION

The operating statement containing revenue, royalties, production costs, transportation costs, and operating income related to oil and natural gas properties in the Waskahigan area (the "Properties") sold by NuVista Energy Ltd. ("NuVista") to Tenth Avenue Petroleum Corp., for the years ended December 31, 2016 and 2015 and six month period ended June 30, 2017 and 2016.

The operating statement has been prepared from the records of NuVista and reflects revenue, royalties, production costs and transportation costs based on the Properties proportional working interests. The operating statement does not include any provision for depletion and depreciation, accretion of decommissioning obligations, future capital costs, impairment of unevaluated properties, general and administrative expense, or income taxes for the properties as these amounts are based on the consolidated operations of NuVista, of which these properties form only a part.

The operating statement has been prepared in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107—*Acceptable Accounting Principles and Auditing Standards* for business statements that are an operating statement of an oil and gas property. The revenue, royalties, production costs, transportation costs and operating income reported in the operating statement for the six months ended June 30, 2017 and 2016, with the years ended December 31, 2016 and 2015 are stated in accordance with International Financial Reporting Standards.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Joint Operations

A portion of the properties are jointly owned, the operating statement only reflects NuVista's proportionate interest.

Revenue Recognition

Revenue includes oil and gas revenues that are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable.

Royalties

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with the applicable regulations and/or terms of individual royalty agreements.

Production Costs

Production costs include all the direct operating expenses related to the lifting, gathering, processing, and delivery to a sales point of the oil, natural gas, and natural gas liquids. Such costs include labor, power, chemicals, repairs and maintenance, trucking, disposal, overhead and other direct costs. Corporate based costs are excluded from the operating statement.

Transportation Costs

Transportation costs include amounts incurred to deliver oil, natural gas, and natural gas liquids to market.