Tenth Avenue Petroleum Corp.
Form 51-101F1
December 31, 2016

Tenth Avenue Petroleum Corp.
Form 51-101F1
Statement of Reserves and Other Oil and Gas Information

The reserves data presented in this form is based upon the "**RESERVES ASSESSMENT AND EVALUATION OF CANADIAN OIL AND GAS PROPERTIES**" by GLJ Petroleum Consultants, with an effective date of December 31, 2016. The reserves data summarizes oil, gas and liquid reserves of Tenth Avenue Petroleum Corp. and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data meets the requirements of National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserve definitions.

All of the Company's reserves are in Western Canada. The Company has not booked reserves for its Texas assets. (El Indio #1H in Maverick County, Texas)

Abbreviations and Conversion

Terms used in NI 51-101 have the same meaning in this Form NI 51-101 F1.

Part 1 Date of Statement

1.1 Relevant Dates

1. Date of Statement: May 1, 2017
2. Effective Date of Statement: December 31, 2016
3. Preparation Date of Statement: May 1, 2017

Part 2 Disclosure of Reserves Data (Forecast Prices and Costs)

This section provides economic forecasts based on current costs and informed interpretation of posted reference prices (summarized in the following table) into the future: Historical price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Table 2.1.1

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE

As of December 31, 2016

Forecast Prices and Costs

RESERVES SUMMARY

	Light And Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
Reserves Category	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mboe	Mboe
Proved										
Producing	2	2	0	0	130	107	21	14	45	34
Developed Nonproducing	0	0	0	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0	0	0	0
Total Proved	2	2	0	0	130	107	21	14	45	34
Total Probable	1	0	0	0	44	36	7	5	15	11
Total Proved Plus Probable	3	2	0	0	174	144	28	19	60	45

NET PRESENT VALUE SUMMARY

	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%		
Reserves Category	M$	M$	M$	M$	M$	$/boe	$/Mcfe
Proved							
Producing	731	554	438	360	305		
Developed Nonproducing	0	0	0	0	0		
Undeveloped	0	0	0	0	0		
Total Proved	731	554	438	360	305		
Total Probable	324	160	88	53	36		
Total Proved Plus Probable	1,055	714	526	413	341		

NET PRESENT VALUES OF FUTURE NET REVENUE

	After Income Taxes Discounted At (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	M$	M$	M$	M$	M$
Proved					
Producing	731	554	438	360	305
Developed Nonproducing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	731	554	438	360	305
Total Probable	324	160	88	53	36
Total Proved Plus Probable	1,055	714	526	413	341

Note: Unit values are based on Company Net Reserves.

Table 2.1.3
TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
As of December 31, 2016
Forecast Prices and Costs

Total Future Net Revenue (Undiscounted)

Reserves Category	Revenue M$	Royalties M$	Operating Costs M$	Capital Development Costs M$	Abandonment Costs M$	Future Net Revenue Before Income Taxes M$	Income Tax M$	Future Net Revenue After Income Taxes M$
Proved Producing	1,450	361	296	0	62	731	-	731
Proved Developed Nonproducing	0	0	0	0	0	0	-	-
Proved Undeveloped	0	0	0	0	0	0	-	-
Total Proved	1,450	361	296	0	62	731	-	731
Total Probable	604	155	118	0	7	324	-	324
Total Proved Plus Probable	2,054	516	414	0	69	1,055	-	1,055

NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP
As of December 31, 2016
Forecast Prices and Costs

Future Net Revenue Before Income Taxes [2]
(Discounted at 10% per year)

Entity Name	Percent Value Discount M$	$/boe	$/Mcfe
Proved Producing			
Light & Medium Oil [1]	49	19.51	3.25
Total Gas	390	12.48	2.08
Total: Proved Producing	438	13.00	2.17
Total Proved			
Light & Medium Oil [1]	49	19.51	3.25
Total Gas	390	12.48	2.08
Total: Total Proved	438	13.00	2.17
Total Proved Plus Probable			
Light & Medium Oil [1]	57	18.24	3.04
Total Gas	469	11.20	1.87
Total: Total Proved Plus Probable	526	11.69	1.95

Notes:
1 Including solution gas and other by-products
2 Unit values are based on Company Net Reserves

Part 3 PRICING ASSUMPTIONS

Item 3.2.1(a) Forecast Prices Used in Estimates

The pricing assumptions used in the GLJ Report to determine net values of future net revenue (forecast) and the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101. Effective January 1, 2017.

Table 1

GLJ Petroleum Consultants

Crude Oil and Natural Gas Liquids

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Effective January 1, 2017

Year	Inflation %	CADUSD Exchange Rate USD/CAD	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Constant 2017 $ USD/bbl	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Then Current USD/bbl	ICE Brent Near Month Contract Crude Oil FOB North Sea Then Current USD/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current CAD/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	WCS Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current CAD/bbl	Light Sour Crude Oil (35 API, 1.2%S) at Cromer Then Current CAD/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane CAD/bbl	Edmonton Propane CAD/bbl	Edmonton Butane CAD/bbl	Edmonton C5+ Stream Quality CAD/bbl
2007	2.1	0.9352	85.35	72.39	72.71	77.06	53.64	52.38	43.42	71.13	65.71	N/A	49.56	61.78	77.38
2008	2.4	0.9428	114.99	99.64	98.30	102.90	84.31	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.8798	69.60	61.78	62.50	66.32	60.18	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.9711	89.25	79.52	80.25	77.87	68.45	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.0115	104.91	95.12	110.86	95.53	78.59	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012	1.5	1.0009	100.94	94.21	111.71	86.60	74.42	73.13	63.64	84.51	81.37	N/A	29.04	66.70	100.84
2013	0.9	0.9711	103.41	97.96	108.77	93.47	76.33	75.01	65.11	92.30	88.13	N/A	38.88	68.81	104.70
2014	1.9	0.9055	97.24	93.00	99.71	94.58	81.08	81.03	73.73	92.68	89.67	N/A	45.53	69.20	102.44
2015	1.1	0.7831	50.04	48.78	53.60	57.20	45.50	44.82	39.25	55.49	51.87	N/A	6.49	36.75	60.42
2016	1.5	0.755	43.93	43.30	45.01	52.95	39.71	38.84	32.66	51.34	48.71	N/A	13.03	34.36	56.12
2017 Q1	2.0	0.750	54.00	54.00	56.00	68.00	52.70	52.02	45.41	66.64	63.24	11.48	29.24	48.96	70.72
2017 Q2	2.0	0.750	54.00	54.00	56.00	68.00	52.70	52.02	45.41	66.64	63.24	10.99	26.52	48.96	70.72
2017 Q3	2.0	0.750	56.00	56.00	58.00	70.67	55.33	54.63	47.96	69.25	65.72	10.99	27.56	50.88	73.49
2017 Q4	2.0	0.750	56.00	56.00	58.00	70.67	55.33	54.63	47.96	69.25	65.72	11.15	30.39	50.88	73.49
2017 Full Year	2.0	0.750	55.00	55.00	57.00	69.33	54.02	53.32	46.69	67.95	64.48	11.15	28.43	49.92	72.11
2018	2.0	0.775	57.84	59.00	61.00	72.26	57.52	56.79	50.40	70.81	67.20	9.92	26.74	54.19	74.79
2019	2.0	0.800	61.51	64.00	66.00	75.00	62.02	61.27	55.03	73.50	69.75	10.52	26.25	56.25	78.75
2020	2.0	0.825	63.14	67.00	70.00	76.36	63.76	63.00	56.96	74.84	71.02	11.27	26.73	57.27	79.80
2021	2.0	0.850	65.59	71.00	74.00	78.82	66.68	65.90	59.95	77.25	73.31	11.87	27.59	59.12	82.37
2022	2.0	0.850	67.02	74.00	77.00	82.35	70.25	69.42	63.43	80.71	76.59	12.54	28.82	61.76	86.06
2023	2.0	0.850	68.37	77.00	80.00	85.88	73.77	72.91	66.99	84.16	79.87	13.20	30.06	64.41	89.32
2024	2.0	0.850	69.64	80.00	83.00	89.41	77.34	76.45	70.48	87.62	83.15	13.56	31.29	67.06	92.99
2025	2.0	0.850	70.84	83.00	86.00	92.94	80.86	79.93	73.63	91.08	86.44	13.83	32.53	69.71	97.59
2026	2.0	0.850	72.00	86.05	89.64	95.61	84.43	83.47	77.54	93.70	88.92	14.13	33.46	71.71	99.91
2027+	2.0	0.850	72.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

A historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

Revised 2016-12-31

Table 2

GLJ Petroleum Consultants

Natural Gas and Sulphur

Price Forecast

Effective January 1, 2017

	NYMEX Henry Hub		Midwest		Alliance	Alberta Plant Gate			Saskatchewan Plant Gate			British Columbia			Alberta
	Near Month Contract		Price	AECO/NIT	Transfer Pool									Sulphur	Sulphur
			at Chicago	Spot	Spot	Spot									
	Constant	Then	Then	Then	Then	Constant	Then					Westcoast	Spot	FOB	at Plant
	2017 $	Current	Current	Current	Current	2017 $	Current	ARP	SaskEnergy	Spot	Sumas Spot	Station 2	Plant Gate	Vancouver	Gate
Year	USD/MMBtu	USD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/lt	CAD/lt
2007	8.39	7.12	6.83	6.45	N/A	7.34	6.23	6.20	6.18	6.35	6.52	6.40	6.16	81.66	42.03
2008	10.27	8.90	8.91	8.16	N/A	9.15	7.94	7.88	8.07	8.04	6.47	8.21	7.99	497.39	488.63
2009	4.69	4.16	4.05	3.99	N/A	4.27	3.79	3.85	3.87	3.83	3.80	3.90	3.70	57.06	24.57
2010	4.93	4.40	4.53	4.01	N/A	4.24	3.78	3.77	3.96	3.85	4.12	3.78	3.63	88.94	48.26
2011	4.44	4.03	4.21	3.62	N/A	3.77	3.42	3.46	3.57	3.58	3.90	3.33	3.18	217.16	171.93
2012	3.03	2.83	2.92	2.40	N/A	2.37	2.21	2.25	2.31	2.26	2.70	2.30	2.12	201.03	157.91
2013	3.93	3.73	3.81	3.18	N/A	3.12	2.96	2.98	3.09	3.10	3.71	3.14	2.94	105.74	74.02
2014	4.47	4.28	5.36	4.50	N/A	4.45	4.26	4.22	4.39	4.42	4.37	4.29	4.07	145.41	110.41
2015	2.70	2.63	2.85	2.70	N/A	2.53	2.47	2.56	2.71	2.61	2.31	1.80	1.59	139.61	128.14
2016	2.59	2.55	2.48	2.19	2.31	1.98	1.95	1.95	2.22	2.09	2.18	1.78	1.60	82.84	60.06
2017 Q1	3.70	3.70	3.85	3.55	3.55	3.30	3.30	3.30	3.40	3.45	3.45	2.95	2.78	80.00	56.67
2017 Q2	3.55	3.55	3.55	3.41	3.41	3.16	3.16	3.16	3.26	3.31	2.75	2.91	2.73	80.00	56.67
2017 Q3	3.55	3.55	3.55	3.41	3.41	3.16	3.16	3.16	3.26	3.31	2.95	2.91	2.73	90.00	70.00
2017 Q4	3.60	3.60	3.65	3.46	3.46	3.20	3.20	3.20	3.30	3.36	3.40	2.96	2.78	90.00	70.00
2017 Full Year	3.60	3.60	3.65	3.46	3.46	3.20	3.20	3.20	3.30	3.36	3.14	2.93	2.76	85.00	63.33
2018	3.14	3.20	3.25	3.10	3.10	2.79	2.85	2.85	2.95	3.00	2.80	2.70	2.52	100.00	79.03
2019	3.27	3.40	3.45	3.27	3.27	2.91	3.02	3.02	3.12	3.17	3.00	2.97	2.80	102.00	77.50
2020	3.39	3.60	3.65	3.49	3.49	3.05	3.24	3.24	3.34	3.39	3.30	3.19	3.01	104.04	76.11
2021	3.51	3.80	3.85	3.67	3.67	3.15	3.41	3.41	3.51	3.57	3.60	3.37	3.19	106.12	74.85
2022	3.62	4.00	4.05	3.86	3.86	3.26	3.60	3.60	3.70	3.76	3.80	3.56	3.38	108.24	77.34
2023	3.73	4.20	4.25	4.05	4.05	3.37	3.79	3.79	3.89	3.95	4.00	3.75	3.57	110.41	79.89
2024	3.75	4.31	4.36	4.16	4.16	3.39	3.90	3.90	4.00	4.06	4.11	3.86	3.68	112.62	82.49
2025	3.75	4.39	4.44	4.24	4.24	3.39	3.97	3.97	4.07	4.14	4.19	3.94	3.76	114.87	85.14
2026	3.75	4.48	4.53	4.32	4.32	3.40	4.06	4.06	4.16	4.22	4.28	4.02	3.84	117.17	87.85
2027+	3.75	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.40	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.

The plant gate price represents the price before raw gas gathering and processing charges are deducted.

AECO/NIT Spot refers to the same-day spot price averaged over the period. Revised 2016-12-31

Item 3.2.1(a) Issuers weighted Average Historical Prices for the most recent Financial Year

The Company's weighted average prices for the year ended December 31, 2016 were as follows:

Oil (light crude)	$47.62/bbl
Natural Gas	$$1.91/mct
Liquids	$17.43/bbl
Propane	$6.87/bbl
Butane	25.92/bbl
Pentane	$47.81/bbl

Part 4 **Reconciliations of Changes in Reserves**

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of the Corporation's gross reserves based on forecast prices and costs.

TABLE FP-5A

DECEMBER 31, 2016
RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2015	2	1	2	2	1	2				24	8	32
Discoveries												
Extensions*												
Infill Drilling*												
Improved Recovery*												
Technical Revisions	1		1	1		1				-0	-1	2
Acquisitions												
Dispositions												
Economic Factors										-0	-1	-1
Production	-0	0	-0	-0	0	-0				-6	0	-6
December 31, 2016	2	1	3	2	1	3				21	7	28

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2015	133	47	180	133	47	180				48	17	65
Discoveries												
Extensions*												
Infill Drilling*												
Improved Recovery*												
Technical Revisions	16	-2	13	16	-2	13				3	-1	2
Acquisitions												
Dispositions												
Economic Factors										-0	-1	-1
Production	-18		-18	-18		-18				-6		-6
December 31, 2016	130	44	174	130	44	174				45	15	60

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions . under Infill Drilling, Improved Recovery and Extensions should be combined and reported as ''Extensions and Improved Recovery''.*

TABLE FP-5B
DECEMBER 31, 2015
RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**
December 31, 2014	2	11	13	2	11	13	0	0	0	29	9	38
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	-0	-11	-11	-0	-11	-11	0	0	0	3	-1	2
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	-4	0	-4
Production	-0	0	-0	-0	0	-0	0	0	0	-4	0	-4
December 31, 2015	2	1	2	2	1	2	0	0	0	24	8	32

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
December 31, 2014	149	60	208	149	60	208	0	0	0	56	30	86
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	27	(7)	21	27	(7)	21	0	0	0	7	(12)	(5)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	()	()
Economic Factors	(21)	(6)	(27)	(21)	(6)	(27)	0	0	0	(8)	(1)	(9)
Production	(22)	0	(22)	(22)	0	(22)	0	0	0	(8)	0	(8)
December 31, 2015	133	47	180	133	47	180	0	0	0	48	17	65

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".*

Part 5 Additional Information Relating to Reserves Data

5.1 Undeveloped Reserves Attributed at Current Year

Proved Undeveloped Reserves

L&M Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		BOE (Mbbl)	
Attributed This Year*	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
0	0	0	0	0	0	0	0	0	0

Probable Undeveloped Reserves

L&M Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		BOE (Mbbl)	
Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
0	0	0	0	0	0	0	0	0	0

* Refers to reserves first attributed in this fiscal year ending on the effective date.

BOE Factors:								
	HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
	COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

5.2 Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Tenth Avenue Petroleum Corp's reserves are evaluated by GLJ Petroleum Consultants which is an independent engineering firm. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Tenth Avenue Petroleum Corp's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company and have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com). Please refer to these documents for a discussion of these matters.

5.3 Future Development Costs

Company Annual Capital Expenditures (M$'s)
Forecast Prices and Costs

Totals

Entity Description	2016	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Subtotal	Remainder	Total	10% Discounted
Proved Producing		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved Plus Probable		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) Tenth Avenue Petroleum Corp expects that it will be able to fund the estimated future development costs from a combination of internally generated cash flow, bank debt and equity financings. The Company anticipates that the cost of future financings will be market driven.

(b) Tenth Avenue Petroleum Corp expects that the costs of funding will not significantly affect disclosed reserves or future net revenue.

Part 6 Other Oil and Gas Information

6.1 Oil & Gas Properties and Wells (as of December 31, 2016)

1. All of the Company's properties are located onshore in Western Canada.

   There are no statutory or other mandatory relinquishments, surrenders, back-ins or change in ownership obligations against these reserves.

2. All wells are in Alberta, Saskatchewan, British Columbia, Canada

Oil and Gas Properties and Wells

		Oil Wells		Gas Wells		Other	
		Gross	Net	Gross	Net	Gross	Net
Alberta	Producing	1	7%	1	35%		
	Non-producing	3	3				
	Total Alberta	0	0				
Saskatchewan	Producing	1	ORR				
British Columbia (1)	Total	0	0				

(1) Water Disposal well

6.2 Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2016.

Unproved properties (acres)

		Gross	Net	Commitments
NIL				

6.3 Forward Contracts

The Company has no Forward Contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs (Cdn wells only)

	Year										Totals		
Entity Description	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Subtotal**	**Remainder**	**Total**	**10% Discounted**
Proved Producing	0	0	6	0	0	0	1	0	0	7	0	7	
Total Proved	0	0	6	0	0	0	1	0	0	7	0	7	
Total Proved Plus Probable	0	0	6	0	0	0	1	0	0	7	0	7	

a. The Company estimates abandonment and reclamation costs on a well by well basis.

b. The Company expects to incur abandonment and reclamation costs on 1 net Canadian wells and 1 Texas wells.

c. The Company has estimated its Cdn well abandonment and reclamation costs to be $65,000 undiscounted (to be completed in summer 2016)

d. There are no amounts for abandonment costs for wells not deducted from future revenue.

e. The Company anticipates abandoning an interest in 0 Cdn well(s) at a cost of $0 within the next three years.

6.5 Tax Horizon

As the Company does not yet have any significant production, it is not required to pay income taxes for the year ending December 31, 2016. Further, the Company does not expect to be taxable in the immediately foreseeable future.

At December 31, 2016, the Company has $19,414,000 of available non-capital loss carry forwards in the US and Canada to reduce taxable income for income tax purposes.

The Company has the following tax pool balances: CDE $269,259; COGPE $1,220,614

6.6.1.1 Costs Incurred in 2016

Costs Incurred

Property acquisition-proved properties	$ Nil
Property acquisition-unproved properties	$ Nil
Exploration (does not include Texas wells)	$ Nil
Development (lease and well equipment)(does not include Texas wells)	$ Nil

6.7 Exploration and Development Activities

1 Viking oil well was drilled and completed in 2012/2013. The El Indio #1H well was drilled in Texas in 2011.

6.8 Production Estimates

The volume of Cdn production estimated for 2017 reflected in the estimates of future and net revenue disclosed under Part 2 is:

SUMMARY OF FIRST YEAR PRODUCTION AND OIL AND GAS RESERVES

	S/B 2017 Average Daily Production										Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Entity Description	**Company Gross bbl/d**	**Company Net bbl/d**	**Company Gross bbl/d**	**Company Net bbl/d**	**Company Gross Mcf/d**	**Company Net Mcf/d**	**Company Gross bbl/d**	**Company Net bbl/d**	**Company Gross bbl/d**	**Company Net bbl/d**	**Company Gross Mbbl**	**Company Net Mbbl**	**Company Gross Mbbl**	**Company Net Mbbl**	**Company Gross MMcf**	**Company Net MMcf**	**Company Gross Mbbl**	**Company Net Mbbl**	**Company Gross Mboe**	**Company Net Mboe**
Proved Producing Canadian Assets	1	1	0	0	43	36	6	4	14	11	2	2	0	0	130	107	21	14	45	34
Total: Proved Producing	**1**	**1**	**0**	**0**	**43**	**36**	**6**	**4**	**14**	**11**	**2**	**2**	**0**	**0**	**130**	**107**	**21**	**14**	**45**	**34**
Proved Developed Nonproducing Canadian Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Proved Developed Nonproducing	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Proved Undeveloped Canadian Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total: Proved Undeveloped	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Proved Canadian Assets	1	1	0	0	43	36	6	4	14	11	2	2	0	0	130	107	21	14	45	34
Total: Total Proved	**1**	**1**	**0**	**0**	**43**	**36**	**6**	**4**	**14**	**11**	**2**	**2**	**0**	**0**	**130**	**107**	**21**	**14**	**45**	**34**
Total Probable Canadian Assets	0	0	0	0	0	0	0	0	0	0	1	0	0	0	44	36	7	5	15	11
Total: Total Probable	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**44**	**36**	**7**	**5**	**15**	**11**
Total Proved Plus Probable Canadian Assets	1	1	0	0	44	37	6	4	14	11	3	2	0	0	174	144	28	28	60	45
Total: Total Proved Plus Probable	**1**	**1**	**0**	**0**	**44**	**37**	**6**	**4**	**14**	**11**	**3**	**2**	**0**	**0**	**174**	**144**	**19**	**19**	**60**	**45**

BOE Factors:							
HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

Note: Does not include any production from Texas assets.

6.9 Production History

The following table summarizes the Corporation's average daily Cdn production volumes during the year ended December 31, 2016 by production type.

Table 6.9.1
Production History – Year ended December 31, 2016

	Oil		**Gas**		**Other – NGL, Propane, Butane and Pentane**	
	(Bbls/day)	Aggregate Bbl	(mcf/day)	Aggregate mcf	(Bbls/day)	Aggregate Bbls
Canadian	1.17	426	50	18,350	7.29	2,662

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