Dundee Energy Limited Partnership

Reserve estimation and economic evaluation

Executive summary

Effective date: December 31, 2017

Deloitte.

700, 850 – 2 Street SW
Calgary AB T2P 0R8
Canada

Tel: 403 267 1700
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www.deloitte.ca

February 28, 2018

Dundee Energy Limited Partnership
Unit B, 1030 Adelaide Street South
London, Ontario N6E 1R6

Attention: Mr. Bruce Sherley

RE: Dundee Energy Limited Partnership
Reserve estimation and economic evaluation

At your request and authorization, Deloitte LLP, has prepared an independent evaluation of certain oil and gas assets of Dundee Energy Limited Partnership (Dundee), effective December 31, 2017.

This report has been prepared for the exclusive use of Dundee Energy Limited Partnership for corporate reporting purposes and no part thereof shall be reproduced, distributed or made available to any other person, company, regulatory body or organization pursuant to Part 5 Section 5.7 of NI 51-101. Deloitte hereby gives its consent to the use of its name and to the said estimates pursuant to Part 5 Section 5.7 Item (2) of NI 51-101.

Pursuant to Part 2 Item 2.1 and 2.2 of Form NI 51-101F1, this report documents the results of the evaluation with the following tables summarizing the total corporate reserves and value: All values are in Canadian dollars unless specified.

- Table 1 – Summary of total corporate reserves and value using forecast prices and costs
- Table 2 – Reserves reconciliation

Deloitte was provided the following Canadian tax pools from Dundee Energy Limited Partnership effective December 31, 2017.

	$ Thousands	Depreciation rate, %
COGPE	$83,336.3	10
CDE	$5.5	30
CEE	$26,519.4	100
Total	**$109,861.1**	

Per NI 51-101 corporate general and administrative expenses and financing costs are not deducted.

The oil and gas reserves calculations and income projections, upon which this report is based, were estimated in accordance with the Canadian Oil and Gas Evaluation Handbook (COGEH) and National Instrument 51-101 (NI 51-101). The Evaluation procedure section included in this report details the reserves definitions, price and market demand forecasts and general procedure used by Deloitte in its determination of this evaluation. The extent and character of ownership and all factual data supplied by Dundee Oil and Gas Limited, General Partner of Dundee Energy Limited Partnership were accepted as presented (see Representation Letter attached within).

This report contains forward looking statements including expectations of future production and capital expenditures. Information concerning reserves may also be deemed to be forward looking as estimates imply that the reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e. operational risks in development, exploration and production; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimates; the uncertainty of estimates and projections relating to production, costs and expenses, political, and environmental factors) and commodity price, and exchange rate fluctuation. Present values for various discount rates documented in this report may not necessarily represent fair market value of the reserves.

A Boe conversion ratio of six (6) Mcf: one (1) barrel has been used within this report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

No value has been assigned in this evaluation for non-reserve lands.

Deloitte is pleased to present its independent reserves evaluation report for Dundee Energy Limited Partnership, effective December 31, 2017, in satisfaction of Part 2 Section 2.1 Item 2 of NI 51-101 and Form 51-101 F2, without reservation.

Yours truly,

Robin G. Bertram, P. Eng.
Partner
Deloitte LLP

/sp

Selection: Canada
Effective: December 31, 2017

TABLE 1
Summary of Marketable Reserves and Value

Dundee Energy Limited Partnership
Deloitte December 31 2017 Forecast

	PDP	PNP	PD	PUD	TP	PB	P+P
Oil (Mbbl)							
Gross Remaining	1,395	99	1,494	600	2,094	829	2,923
Company Interest	1,309	80	1,389	600	1,989	796	2,785
Working Interest	1,301	80	1,382	600	1,982	795	2,776
Royalty Interest	7	-	7	-	7	1	9
Company Net	1,109	68	1,177	503	1,680	676	2,356
Gas (MMcf)							
Gross Remaining	73,635	2,318	75,953	8,621	84,573	18,925	103,499
Company Interest	72,017	1,842	73,859	8,621	82,479	18,529	101,009
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Royalty Interest	7	-	7	-	7	1	8
Company Net	60,908	1,538	62,446	7,219	69,664	15,496	85,160
NGLs (Mbbl)							
Gross Remaining	5	-	5	3	8	3	11
Company Interest	4	-	5	3	8	2	11
Working Interest	4	-	5	3	8	2	11
Royalty Interest	-	-	-	-	-	-	-
Company Net	4	-	4	3	7	2	9
Sulphur (MLt)							
Gross Remaining	-	-	-	-	-	-	-
Company Interest	-	-	-	-	-	-	-
Working Interest	-	-	-	-	-	-	-
Royalty Interest	-	-	-	-	-	-	-
Company Net	-	-	-	-	-	-	-
BOE (Mbbl)							
Gross Remaining	13,672	485	14,158	2,040	16,198	3,986	20,184
Company Interest	13,316	387	13,704	2,040	15,744	3,887	19,631
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Royalty Interest	9	-	9	-	9	2	10
Company Net	11,264	325	11,588	1,709	13,298	3,260	16,558
Revenue (M$C)							
Undiscounted	259,308	9,564	268,872	51,980	320,852	134,952	455,805
5%	131,788	5,795	137,583	28,681	166,263	50,773	217,036
8%	97,985	4,538	102,524	21,285	123,808	33,308	157,116
10%	83,263	3,925	87,188	17,726	104,913	26,324	131,238
15%	60,382	2,860	63,242	11,635	74,877	16,259	91,136
20%	47,491	2,191	49,682	7,872	57,554	11,074	68,628

TABLE 2
Dundee Energy Limited Partnership
RESERVES RECONCILIATION SUMMARY
Working Interest
Canada

Effective December 31, 2017
Opening: Deloitte December 31, 2016 Forecast Pricing
Closing: Deloitte December 31, 2017 Forecast Pricing

	Proved Developed Producing					Total Proved					Probable					Proved + Probable				
	Light & Medium Oil	Conventional Gas	Coalbed Methane	NGL	BOE	Light & Medium Oil	Conventional Gas	Coalbed Methane	NGL	BOE	Light & Medium Oil	Conventional Gas	Coalbed Methane	NGL	BOE	Light & Medium Oil	Conventional Gas	Coalbed Methane	NGL	BOE
	Mstb	MMcf	MMcf	Mstb	Mboe	Mstb	MMcf	MMcf	Mstb	Mboe	Mstb	MMcf	MMcf	Mstb	Mboe	Mstb	MMcf	MMcf	Mstb	Mboe
Opening Balance	1,474.0	84,490.3	130.9	6.2	15,583.7	2,178.6	96,227.8	130.9	10.6	18,249.0	849.8	19,466.8	78.7	3.3	4,110.7	3,028.4	115,694.6	209.6	13.9	22,359.7
Production	-129.6	-3,676.7	-14.4	-0.3	-745.1	-129.6	-3,676.7	-14.4	-0.3	-745.1	0.0	0.0	0.0	0.0	0.0	-129.6	-3,676.7	-14.4	-0.3	-745.1
Technical Revisions																				
Technical Revisions	-32.1	-8,840.7	-35.2	-1.4	-1,512.8	-56.0	-10,094.3	-35.2	-2.1	-1,746.3	-49.8	-965.8	-52.2	-0.8	-220.2	-105.8	-11,060.1	-87.4	-2.9	-1,966.6
Working Interest Errors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Changes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Abandonment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revisions Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eval Date Rollover	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Logical Entity Change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Admin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Software Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery																				
Drilling Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Recompletion Workover	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Category Transfer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Enhanced Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exploration Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisition	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors																				
Economic Factors	-10.9	-21.1	-23.2	-0.1	-18.3	-11.3	-42.4	-23.2	-0.1	-22.3	-5.4	-9.0	10.4	0.0	-5.2	-16.8	-51.4	-12.9	-0.1	-27.6
NI 51-101 Regulations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	1,301.5	71,951.8	58.0	4.4	13,307.5	1,981.7	82,414.4	58.0	8.1	15,735.2	794.6	18,492.0	36.9	2.5	3,885.2	2,776.3	100,906.4	94.9	10.6	19,620.4

Deloitte.

Independent petroleum consultants consent

The undersigned firm of Independent Qualified Reserves Evaluators and Auditors of Calgary, Alberta, Canada has prepared an independent evaluation of reserves and future net revenues derived therefrom, of the Petroleum and Natural Gas assets of the interests of Dundee Energy Limited Partnership according to the Canadian Oil and Gas Evaluation Handbook. If required, these reserves and future net revenues were estimated using forecast prices and costs (before and after income taxes) according to the requirements of National Instrument 51-101 (NI 51-101). The effective date of this evaluation is December 31, 2017.

In the course of the evaluation, Dundee Oil and Gas Limited, the General Partner of Dundee Energy Limited Partnership provided Deloitte personnel with basic information which included land, well and accounting (product prices and operating costs) information; reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from Deloitte non confidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted.

A "Representation Letter" dated February 26, 2018 and signed by both the President and the Manager, Engineering was received from Dundee Oil and Gas Limited, the General Partner of Dundee Energy Limited Partnership prior to the finalization of this report. This letter specifically addressed the accuracy, completeness and materiality of all the data and information that was supplied to us during the course of our evaluation of Dundee Energy Limited Partnership's reserves and net present values. This letter is included within.

A field inspection and environmental/safety assessment of the properties was beyond the scope of the engagement of Deloitte and none was carried out. The "Representation Letter" received from Dundee Oil and Gas Limited, the General Partner of Dundee Energy Limited Partnership provided assurance that no additional information necessary for the completion of our assignment would have been obtained by a field inspection.

The accuracy of any reserve and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserve and production estimates presented herein are considered reasonable, and adhere to the COGE Handbook and NI 51-101 (as applicable), the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, current exchange rates, inflation, market demand and government policy which are subject to uncertainties and may in future differ materially from the forecasts herein. Present values of future net revenues documented in this report do not necessarily represent the fair market value of the reserves evaluated herein.

PERMIT TO PRACTICE

Deloitte LLP
Permit Number: P-11444

The Association of Professional Engineers
and Geoscientists of Alberta

Deloitte.

Certificate of qualification

I, R. G. Bertram, a Professional Engineer, of 700, 850 – 2nd Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am a partner of Deloitte LLP, which did prepare an evaluation of certain oil and gas assets of the interests of Dundee Energy Limited Partnership. The effective date of this evaluation is December 31, 2016.

2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Dundee Energy Limited Partnership.

3. I attended the University of Alberta and graduated with a Bachelor of Science Degree in Petroleum Engineering in 1985; that I am a Registered Professional Engineer in the Province of Alberta; and I have in excess of 32 years of engineering experience.

4. I am a Qualified Reserves Auditor as defined in the Canadian Oil and Gas Evaluation Handbook, Volume 1, Section 3.2.

5. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "R. G. Bertram"
R. G. Bertram, P. Eng.

February 28, 2018
Date

Deloitte.

Certificate of qualification

I, D. L. Horbachewski, a Professional Geologist, of 700, 850 – 2nd Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am an employee of Deloitte LLP, which did prepare an evaluation of certain oil and gas assets of the interests of Dundee Energy Limited Partnership. The effective date of this evaluation is December 31, 2017.

2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Dundee Energy Limited Partnership.

3. I attended the University of Calgary and graduated with a Bachelor of Science Degree in Geology in 1999; that I am a Registered Professional Geologist in the Province of Alberta; and I have in excess of eighteen years of evaluations experience.

4. I am a Qualified Reserves Auditor as defined in the Canadian Oil and Gas Evaluation Handbook, Volume 1, Section 3.2.

5. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "D. L. Horbachewski"
D. L. Horbachewski, P. Geol.

February 28, 2018
Date

DUNDEE
ENERGY LP

February 26, 2018

Deloitte LLP
700, 850 - 2nd Street SW
Calgary, Alberta
T2P 0R8

Re: Standard Representation Letter
Corporate Reserve Evaluation

Regarding the evaluation of our Company's oil and gas reserves and independent appraisal of the economic value of these reserves effective December 31, 2017 (the "effective date"), we herein confirm to the best of our knowledge and belief as of the effective date of the reserves evaluation, the following representations and information made to you during the course and conduct of the evaluation.

1. We (the "Client") have made available to you (the "Evaluator") certain records, information and data relating to the evaluated properties that we confirm is, with the exception of immaterial items, complete and accurate as of the effective date of the reserves evaluation including the following:

    a. accounting, financial and contractual data
    b. asset ownership and related encumbrance information
    c. details concerning product marketing, transportation and processing arrangement
    d. all technical information including geological, engineering and production and test data
    e. estimates of future abandonment and reclamation costs.

2. We confirm that all financial and accounting information provided to you is, to the best of our knowledge, both on an individual entity basis and in total, entirely consistent with that reported by our Company for public disclosure and annual audit purposes.

3. We confirm that our Company has satisfactory title to all of the assets, whether tangible, intangible or otherwise, for which accurate and current ownership information has been provided.

4. With respect to all information provided to you regarding product marketing, transportation and processing arrangements, we confirm that we have disclosed to you all anticipated changes, terminations and additions to these arrangements that could reasonably be expected to have a material impact on the evaluation of our Company's reserves and future net revenues.

5. With the possible exception of items of an immaterial nature, we confirm as of the effective date of the evaluation that:

    a. For all operated properties that you have evaluated, no changes have occurred or are reasonably expected to occur to the operating conditions or methods that have been used by our Company over the past twelve (12) months, except as disclosed to you. In the case of non-operated properties, we have advised you of any changes of which we have been made aware.
    b. This letter provides assurance that no additional information necessary for the completion of your assignment would have been obtained by a field inspection.

c. All regulatory approvals, permits and licenses required to allow continuity of future operations and production from the evaluated properties are in place and, except as disclosed to you, there are no directives, orders, penalties or regulatory rulings in effect or expected to come into effect relating to the evaluated properties.
d. Except as disclosed to you, the producing trend and status of each evaluated well or entity in effect throughout the three month period preceding the effective date of the evaluation are consistent with those that existed for the same well or entity immediately prior to this period.
e. Except as disclosed to you, we have no plans or intentions related to the ownership, development or operation of the evaluated properties that could reasonably be expected to materially affect the production levels or recovery of reserves from the evaluated properties.
f. If material changes of an adverse nature occur in the Company's operating performance subsequent to the effective date and prior to the report date, we will undertake to inform you of such material changes prior to requesting your approval for any public disclosure of reserves information.
g. Between the effective date of the report and the date of this letter, nothing has come to our attention that has materially affected or could materially affect our reserves and the economic value of these reserves that has not been disclosed to you.

Yours truly,

DUNDEE OIL AND GAS LIMITED
General Partner of DUNDEE ENERGY LP

Bruce Sherley	Frank Kuri
President	Manager, Engineering

Deloitte.

NI 51-101 Form F2
Report on reserves data
by
independent qualified reserves
evaluator or auditor

To the Board of Directors of Dundee Energy Limited in respect to the assets held by Dundee Energy Limited Partnership (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year end December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent qualified reserves evaluator or auditor	Description and preparation date of evaluation report	Location of reserves (country or foreign geographic area)	Net present value of future net revenue (before income taxes, 10% discount rate)			
			Audited $M	Evaluated $M	Reviewed $M	Total $M
Deloitte LLP	Dundee Energy Limited Partnership Reserve estimation and economic evaluation December 31, 2017	Canada	-	$131,237.8	-	$131,237.8

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

Original signed by: "Robin G. Bertram"
Robin G. Bertram, P. Eng.
Partner

Execution date: February 28, 2018

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Executive summary

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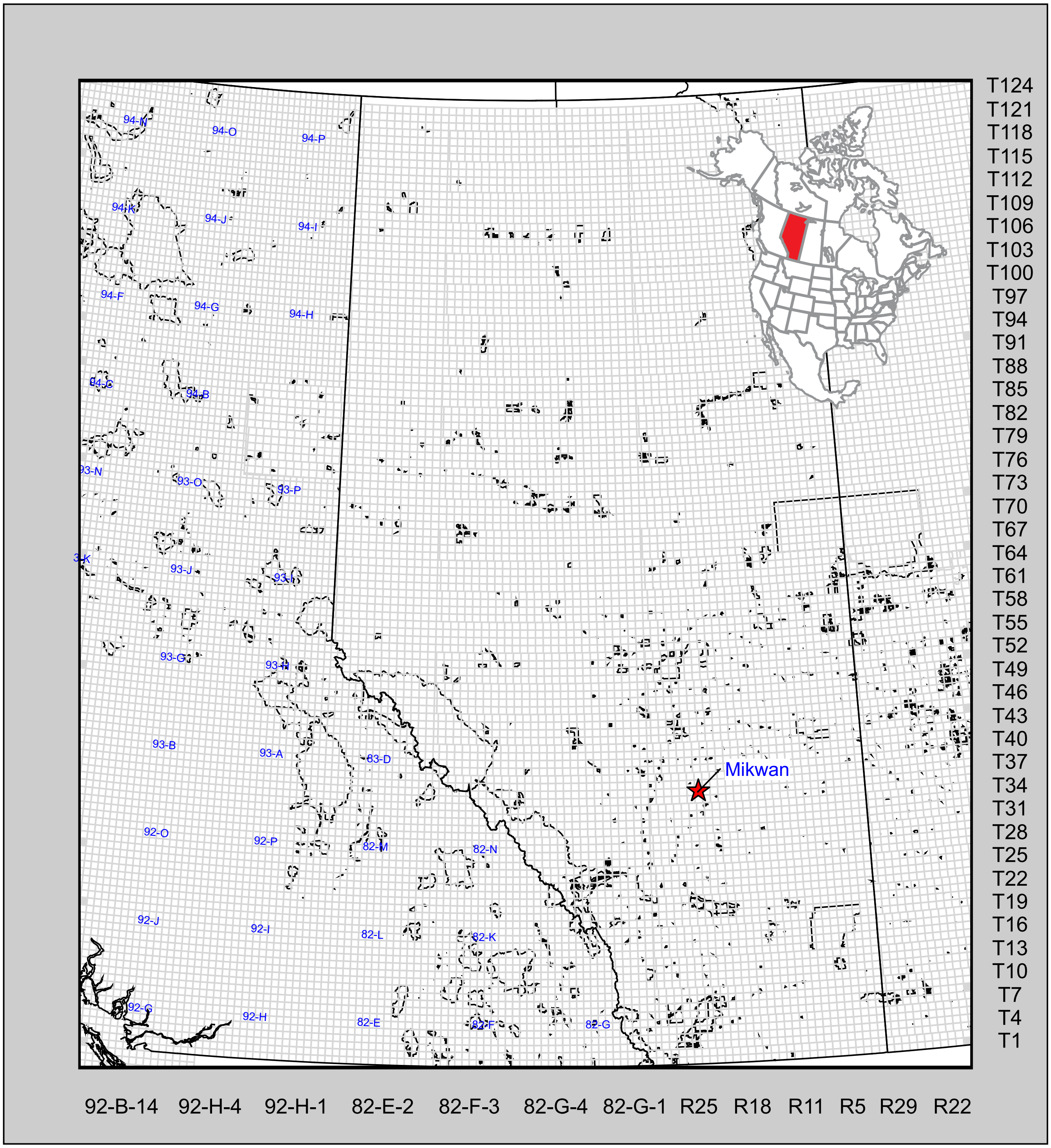
Economics

- Deloitte December 31, 2017 forecast price

Evaluation procedure

Effective date: December 31, 2017



Kilometres

0 100 200 300

0 100 200

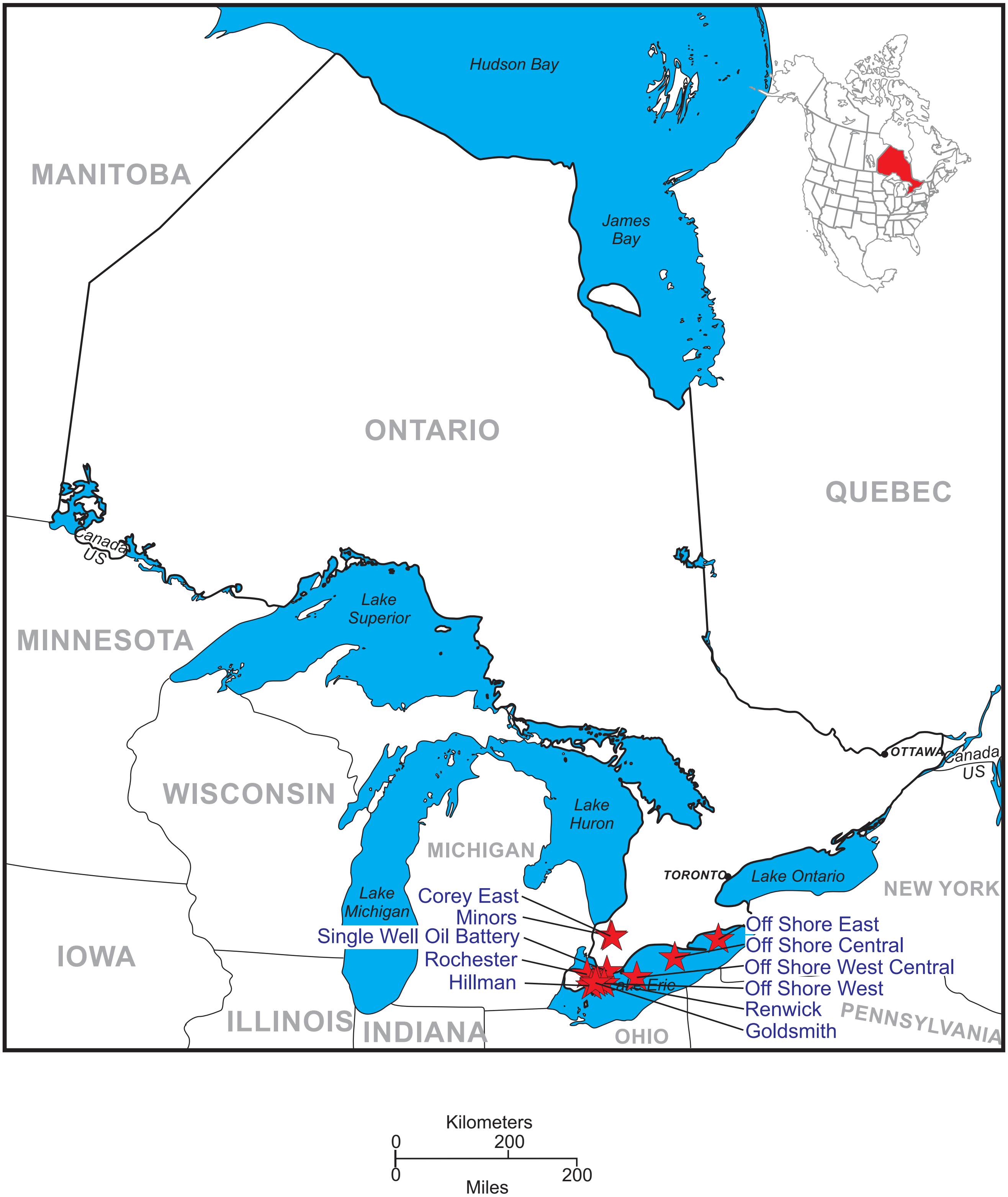
Miles

Legend
★ Evaluated Property

Deloitte.

Dundee Energy Limited Partnership
Property Location
Effective December 31, 2017

geoSCOUT www.geologic.com	By : laj	Date : 2017/01/21
	Scale = 1:7500000	Project : dun loc



Legend
★ Evaluated Property

Deloitte.

Dundee Energy Limited Partnership
Property Locations Effective December 31, 2017

By : laj		Date : 2017/01/21
Project : dun loc		
Source : http://maps.ogrslibrary.com/		

Summary of Marketable Reserves and Value

	PDP	PNP	PD	PUD	TP	PB	P+P
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Royalty Interest	-	-	-	-	-	-	-
Company Net	4	-	4	3	7	2	9
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Company Interest	-	-	-	-	-	-	-
Working Interest	-	-	-	-	-	-	-
Royalty Interest	-	-	-	-	-	-	-
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Revenue (M$C)							
Undiscounted	259,308	9,564	268,872	51,980	320,852	134,952	455,805
5%	131,788	5,795	137,583	28,681	166,263	50,773	217,036
8%	97,985	4,538	102,524	21,285	123,808	33,308	157,116
10%	83,263	3,925	87,188	17,726	104,913	26,324	131,238
15%	60,382	2,860	63,242	11,635	74,877	16,259	91,136
20%	47,491	2,191	49,682	7,872	57,554	11,074	68,628

Selection: Canada
Effective: December 31, 2017

Oil and Gas Economic Indicators

Dundee Energy Limited Partnership
Deloitte December 31 2017 Forecast

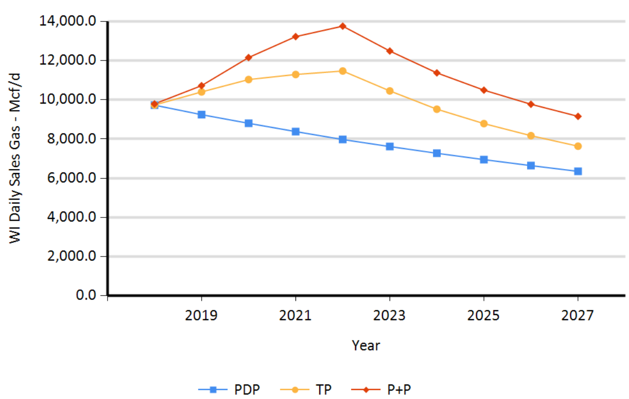
Net Present Value Before Tax (M$C)

Discount Rates	PDP	PD	TP	P+P
Undiscounted	259,308	268,872	320,852	455,805
5%	131,788	137,583	166,263	217,036
8%	97,985	102,524	123,808	157,116
10%	83,263	87,188	104,913	131,238
15%	60,382	63,242	74,877	91,136
20%	47,491	49,682	57,554	68,628

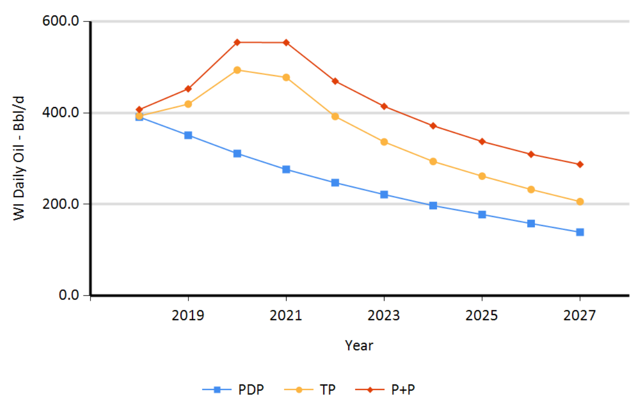
Company Interest Reserves

Product		PDP	PD	TP	P+P
Oil	(Mbbl)	1,309	1,389	1,989	2,785
Gas	(MMcf)	72,017	73,859	82,479	101,009
NGLs	(Mbbl)	4	5	8	11
Sulphur	(MLt)	-	-	-	-
BOE	**(Mbbl)**	**13,316**	**13,704**	**15,744**	**19,631**
Mcfe	**(MMcf)**	**79,897**	**82,222**	**94,463**	**117,783**

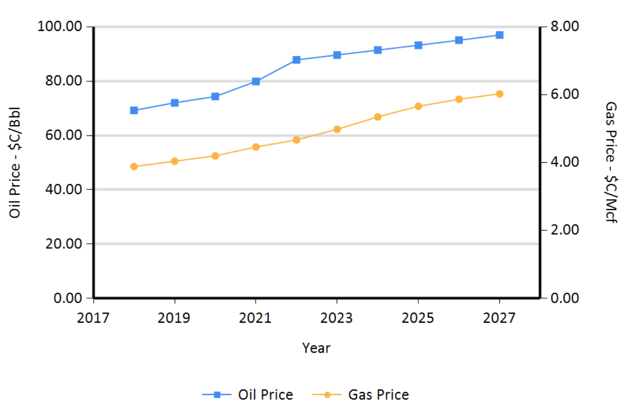
Daily Sales Gas (WI)



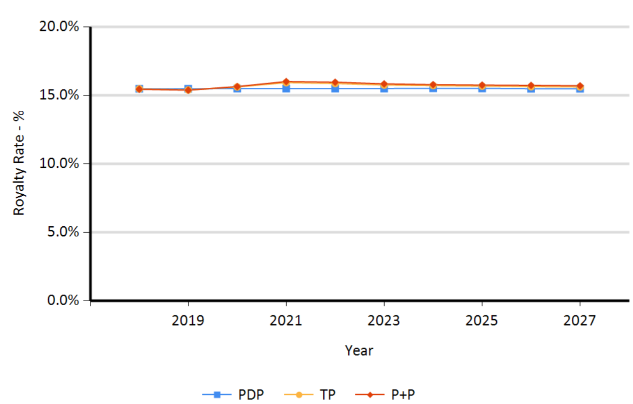
Daily Oil (WI)



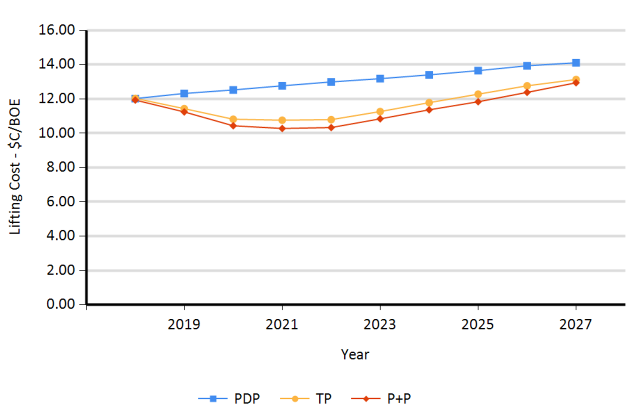
Calculated Oil and Gas Prices



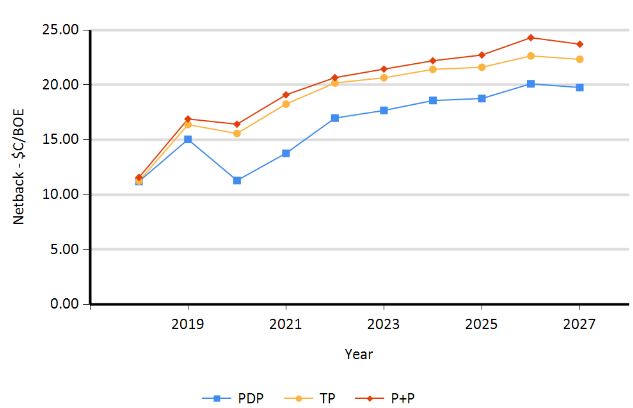
Royalty Rates



Lifting Cost



Netback



Selection: Canada
Effective: December 31, 2017

Detailed Reserves and Present Value

Dundee Energy Limited Partnership
Deloitte December 31 2017 Forecast

	Oil (Mbbl)			Sales Gas (MMcf)			NGL (Mbbl)			BOE (MBOE)			Present Values (M$C)		
Entity Description	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**0%**	**5%**	**10%**
Proved Developed Producing															
Canada															
Abandonment													($82,458.3)	($24,905.4)	($14,665.5)
Total													($82,458.3)	($24,905.4)	($14,665.5)
Alberta															
Mikwan				58.0		47.8				9.7		8.0	$19.9	$13.9	$10.1
Alberta Total				58		48				10		8	$19.9	$13.9	$10.1
Ontario															
Corey East	69.1		59.0							69.1		59.0	$3,556.2	$2,395.8	$1,773.6
Goldsmith	249.6		208.4	225.6		185.6	2.6		2.2	289.8		241.5	$11,114.4	$7,716.7	$5,833.6
Hillman	336.8		288.4	292.1		249.0				385.4		329.9	$16,758.7	$11,841.4	$9,167.2
Minors	1.2	7.4	8.4							1.2	7.4	8.4	$958.5	$394.6	$235.2
Off Shore Central				18,909.7		15,600.5				3,151.6		2,600.1	$69,612.7	$28,481.5	$16,468.8
Off Shore East				41,632.8	7.1	35,656.1				6,938.8	1.2	5,942.7	$194,344.7	$78,785.2	$44,987.0
Off Shore West				4,043.9		3,507.2				674.0		584.5	$14,582.4	$6,338.7	$3,764.9
Off Shore West Central				6,508.4		5,388.6				1,084.7		898.1	$2,732.3	$1,886.6	$1,488.6
Petrolia East	153.2		133.7							153.2		133.7	$10,338.7	$5,854.5	$3,979.1
Renwick	246.7		199.2	272.8		214.6	1.8		1.4	293.9		236.4	$8,615.6	$6,337.4	$4,975.6
Rochester	61.8		54.1							61.8		54.1	$1,401.7	$1,168.9	$1,000.5
Single Well Oil Battery	183.2		157.4	66.6		58.2				194.2		167.1	$7,730.7	$5,478.4	$4,244.3
Ontario Total	1,301	7	1,109	71,952	7	60,860	4		4	13,298	9	11,256	$341,746.6	$156,679.8	$97,918.4
Canada Total	1,301	7	1,109	72,010	7	60,908	4		4	13,308	9	11,264	$259,308.2	$131,788.3	$83,262.9
Proved Developed Producing Total	1,301	7	1,109	72,010	7	60,908	4		4	13,308	9	11,264	$259,308.2	$131,788.3	$83,262.9
Proved Developed															
Canada															
Abandonment													($82,458.3)	($24,905.4)	($14,665.5)
Total													($82,458.3)	($24,905.4)	($14,665.5)
Alberta															
Mikwan				58.0		47.8				9.7		8.0	$19.9	$13.9	$10.1
Alberta Total				58		48				10		8	$19.9	$13.9	$10.1
Ontario															
Corey East	69.1		59.0							69.1		59.0	$3,556.2	$2,395.8	$1,773.6

Detailed Reserves and Present Value

	Oil (Mbbl)			Sales Gas (MMcf)			NGL (Mbbl)			BOE (MBOE)			Present Values (M$C)		
Entity Description	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**0%**	**5%**	**10%**
Goldsmith	268.3		222.9	245.8		201.3	2.9		2.4	312.1		258.8	$12,357.9	$8,520.5	$6,402.0
Hillman	374.8		321.7	316.2		270.1				427.5		366.7	$19,072.3	$13,184.3	$10,067.7
Minors	15.3	7.4	20.8	364.8		319.2				76.1	7.4	73.9	$3,187.4	$1,652.1	$1,036.8
Off Shore Central				18,909.7		15,600.5				3,151.6		2,600.1	$69,612.7	$28,481.5	$16,468.8
Off Shore East				41,632.8	7.1	35,656.1				6,938.8	1.2	5,942.7	$194,344.7	$78,785.2	$44,987.0
Off Shore West				4,043.9		3,507.2				674.0		584.5	$14,582.4	$6,338.7	$3,764.9
Off Shore West Central				7,941.2		6,570.6				1,323.5		1,095.1	$6,260.0	$4,086.7	$2,992.4
Petrolia East	153.2		133.7							153.2		133.7	$10,338.7	$5,854.5	$3,979.1
Renwick	246.7		199.2	272.8		214.6	1.8		1.4	293.9		236.4	$8,615.6	$6,337.4	$4,975.6
Rochester	71.3		62.4							71.3		62.4	$1,652.3	$1,359.2	$1,150.7
Single Well Oil Battery	183.2		157.4	66.6		58.2				194.2		167.1	$7,730.7	$5,478.4	$4,244.3
Ontario Total	1,382	7	1,177	73,794	7	62,398	5		4	13,685	9	11,580	$351,310.8	$162,474.3	$101,843.0
Canada Total	1,382	7	1,177	73,852	7	62,446	5		4	13,695	9	11,588	$268,872.4	$137,582.8	$87,187.6
Proved Developed Total	1,382	7	1,177	73,852	7	62,446	5		4	13,695	9	11,588	$268,872.4	$137,582.8	$87,187.6
Total Proved															
Canada															
Abandonment													($82,458.3)	($24,905.4)	($14,665.5)
Total													($82,458.3)	($24,905.4)	($14,665.5)
Alberta															
Mikwan				58.0		47.8				9.7		8.0	$19.9	$13.9	$10.1
Alberta Total				58		48				10		8	$19.9	$13.9	$10.1
Ontario															
Corey East	69.1		59.0							69.1		59.0	$3,556.2	$2,395.8	$1,773.6
Goldsmith	618.3		508.2	539.8		440.9	6.3		5.2	714.6		586.8	$33,708.5	$21,233.6	$15,160.0
Hillman	374.8		321.7	316.2		270.1				427.5		366.7	$19,072.3	$13,184.3	$10,067.7
Minors	15.3	7.4	20.8	364.8		319.2				76.1	7.4	73.9	$3,187.4	$1,652.1	$1,036.8
Off Shore Central				21,934.9		18,096.3				3,655.8		3,016.1	$73,887.7	$31,186.5	$18,119.1
Off Shore East				43,379.6	7.1	37,184.5				7,229.9	1.2	6,197.4	$196,397.5	$79,679.0	$45,135.7
Off Shore West				5,627.0		4,835.4				937.8		805.9	$17,768.0	$7,752.8	$4,339.2
Off Shore West Central				9,912.8		8,197.2				1,652.1		1,366.2	$10,302.3	$6,096.3	$4,054.8
Petrolia East	403.2		351.8							403.2		351.8	$27,412.3	$14,799.4	$9,511.2
Renwick	246.7		199.2	272.8		214.6	1.8		1.4	293.9		236.4	$8,615.6	$6,337.4	$4,975.6

Detailed Reserves and Present Value

	Oil (Mbbl)			Sales Gas (MMcf)			NGL (Mbbl)			BOE (MBOE)			Present Values (M$C)		
Entity Description	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**WI**	**RI**	**Net**	**0%**	**5%**	**10%**
Rochester	71.3		62.4							71.3		62.4	$1,652.3	$1,359.2	$1,150.7
Single Well Oil Battery	183.2		157.4	66.6		58.2				194.2		167.1	$7,730.7	$5,478.4	$4,244.3
Ontario Total	1,982	7	1,680	82,414	7	69,616	8		7	15,726	9	13,290	$403,290.7	$191,154.9	$119,568.9
Canada Total	1,982	7	1,680	82,472	7	69,664	8		7	15,735	9	13,298	$320,852.3	$166,263.4	$104,913.4
Total Proved Total	1,982	7	1,680	82,472	7	69,664	8		7	15,735	9	13,298	$320,852.3	$166,263.4	$104,913.4
Total Proved Plus Probable															
Canada															
Abandonment													($82,690.6)	($24,843.6)	($14,630.6)
Total													($82,690.6)	($24,843.6)	($14,630.6)
Alberta															
Mikwan				94.9		78.2				15.8		13.0	$59.7	$36.3	$23.7
Alberta Total				95		78				16		13	$59.7	$36.3	$23.7
Ontario															
Corey East	113.8		97.1							113.8		97.1	$6,776.2	$3,590.9	$2,352.6
Goldsmith	786.8		646.3	691.7		564.7	8.1		6.6	910.2		747.1	$45,233.1	$26,526.7	$18,277.7
Hillman	546.5		468.0	466.6		397.4				624.3		534.2	$30,833.9	$18,733.2	$13,368.2
Minors	22.8	8.9	28.8	542.9		475.1				113.3	8.9	108.0	$4,875.7	$2,198.9	$1,284.2
Off Shore Central				26,330.1		21,722.3				4,388.4		3,620.4	$92,945.4	$37,766.4	$21,244.4
Off Shore East				48,200.7	7.6	41,317.6				8,033.4	1.3	6,886.3	$228,487.4	$88,701.7	$48,930.1
Off Shore West				7,153.8		6,127.9				1,192.3		1,021.3	$24,318.8	$10,256.4	$5,600.7
Off Shore West Central				16,996.8		14,050.8				2,832.8		2,341.8	$34,712.6	$15,544.7	$8,892.2
Petrolia East	536.4		468.0							536.4		468.0	$41,014.1	$19,289.9	$11,691.1
Renwick	337.4		273.1	382.0		301.9	2.5		2.0	403.6		325.4	$12,387.0	$8,291.8	$6,144.3
Rochester	167.8		146.8							167.8		146.8	$4,923.9	$3,418.5	$2,600.4
Single Well Oil Battery	264.9		227.8	141.7		124.0				288.5		248.4	$11,927.5	$7,524.5	$5,458.7
Ontario Total	2,776	9	2,356	100,906	8	85,082	11		9	19,605	10	16,545	$538,435.6	$241,843.6	$145,844.7
Canada Total	2,776	9	2,356	101,001	8	85,160	11		9	19,620	10	16,558	$455,804.7	$217,036.3	$131,237.8
Total Proved Plus Probable Total	2,776	9	2,356	101,001	8	85,160	11		9	19,620	10	16,558	$455,804.7	$217,036.3	$131,237.8

Dundee Energy Limited Partnership
NI 51-101 FORECAST CASE
OIL AND GAS RESERVES SUMMARY
Deloitte December 31, 2017 Forecast Pricing
Canada

Effective December 31, 2017

VOLUMES IN IMPERIAL UNITS

	Oil		Natural Gas							
	Light/Medium Crude		Conventional		Coalbed Methane		Natural Gas Liquids		Total BOE	
CATEGORY	WI Gross Mstb	Co. Share Net Mstb	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross Mstb	Co. Share Net Mstb	WI Gross Mboe	Co. Share Net Mboe
PDP	1,301.5	1,108.6	71,951.8	60,859.8	58.0	47.8	4.4	3.6	13,307.5	11,263.5
PDNP	80.3	68.4	1,841.9	1,538.0	0.0	0.0	0.2	0.2	387.5	324.9
PUD	600.0	503.3	8,620.7	7,218.6	0.0	0.0	3.4	2.8	2,040.2	1,709.3
TP	1,981.7	1,680.3	82,414.4	69,616.4	58.0	47.8	8.1	6.6	15,735.2	13,297.6
PB	794.6	675.5	18,492.0	15,465.3	36.9	30.4	2.5	2.0	3,885.2	3,260.2
P+P	2,776.3	2,355.9	100,906.4	85,081.7	94.9	78.2	10.6	8.6	19,620.4	16,557.8

VOLUMES IN METRIC UNITS

	Oil		Natural Gas							
	Light/Medium Crude		Conventional		Coalbed Methane		Natural Gas Liquids		Total BOE	
CATEGORY	WI Gross E^3m^3	Co. Share Net E^3m^3	WI Gross E^6m^3	Co. Share Net E^6m^3	WI Gross E^6m^3	Co. Share Net E^6m^3	WI Gross E^3m^3	Co. Share Net E^3m^3	WI Gross E^3m^3e	Co. Share Net E^3m^3e
PDP	206.8	176.2	2,027.2	1,714.7	1.6	1.3	0.7	0.6	2,114.7	1,789.9
PDNP	12.8	10.9	51.9	43.3	0.0	0.0	0.0	0.0	61.6	51.6
PUD	95.3	80.0	242.9	203.4	0.0	0.0	0.5	0.4	324.2	271.6
TP	314.9	267.0	2,321.9	1,961.4	1.6	1.3	1.3	1.0	2,500.5	2,113.1
PB	126.3	107.4	521.0	435.7	1.0	0.9	0.4	0.3	617.4	518.1
P+P	441.2	374.4	2,842.9	2,397.1	2.7	2.2	1.7	1.4	3,117.9	2,631.2

Dundee Energy Limited Partnership
NI 51-1010 FORECAST CASE
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
Deloitte December 31, 2017 Forecast Pricing
Canada

Effective December 31, 2017

	Before Income Tax					After Income Tax					Unit Value Before Income Tax
RESERVES CATEGORY	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	Discounted at 10% $/boe
Proved Developed Producing	259,308.2	131,788.3	83,262.9	60,381.6	47,490.8	209,551.4	116,488.9	76,988.3	57,308.4	45,812.5	7.39
Proved Developed Non-Producing	9,564.2	5,794.5	3,924.6	2,860.3	2,190.9	7,029.7	4,374.6	3,057.3	2,299.1	1,812.8	12.08
Proved Undeveloped	51,979.9	28,680.6	17,725.8	11,635.3	7,872.2	38,067.0	20,961.7	12,861.7	8,342.8	5,541.0	10.37
Proved	320,852.3	166,263.4	104,913.4	74,877.3	57,553.9	254,648.1	141,825.2	92,907.3	67,950.4	53,166.3	7.89
Probable	134,952.4	50,772.9	26,324.4	16,258.8	11,073.6	99,242.0	37,331.3	19,373.0	11,989.6	8,190.8	8.07
Proved Plus Probable	455,804.7	217,036.3	131,237.8	91,136.1	68,627.6	353,890.1	179,156.6	112,280.4	79,940.0	61,357.1	7.93

*Unit value calculation based on Net BOE reserves

Dundee Energy Limited Partnership
NI 51-1010 FORECAST CASE
TOTAL FUTURE NET REVENUE - WITH CORPORATE TAX POOLS
Deloitte December 31, 2017 Forecast Pricing
Canada

Effective December 31, 2017

CATEGORY	Revenue* M$	Royalties M$	Operating Costs M$	Investment Costs M$	Well Abandonment Costs M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Proved Developed Producing	621,300.9	95,480.0	183,904.8	0.0	82,607.9	259,308.2	49,756.8	209,551.4
Proved Developed Non-Producing	19,050.9	3,003.3	6,195.4	288.0	0.0	9,564.2	2,534.5	7,029.7
Proved Undeveloped	109,988.6	17,833.7	21,694.5	16,015.5	2,465.1	51,979.9	13,912.9	38,067.0
Proved	750,340.4	116,317.0	211,794.6	16,303.5	85,073.0	320,852.3	66,204.2	254,648.1
Probable	238,328.1	37,683.8	60,139.2	4,637.8	914.9	134,952.4	35,710.4	99,242.0
Proved Plus Probable	988,668.5	154,000.8	271,933.8	20,941.3	85,987.9	455,804.7	101,914.6	353,890.1

* Revenue includes product revenue and other income from facilities, wells and corporate if specified.

Dundee Energy Limited Partnership
NI 51-101 FORECAST CASE
FUTURE NET REVENUE BY PRODUCTION TYPE
Deloitte December 31, 2017 Forecast Pricing
Canada

Effective December 31, 2017

	FUTURE NET REVENUE BEFORE INCOME TAXES* 10% M$	UNIT VALUE Primary Product Only	
TOTAL PROVED			
Conventional Natural Gas	64,581.3	0.94	$/Mcf
Coal Bed Methane	-13.4	-0.28	$/Mcf
Light and Medium Crude Oil	40,345.5	24.02	$/bbl
Total	104,913.4	8.02	$/BOE
TOTAL PROVED + PROBABLE			
Conventional Natural Gas	77,660.3	0.93	$/Mcf
Coal Bed Methane	3.8	0.05	$/Mcf
Light and Medium Crude Oil	53,573.7	22.75	$/bbl
Total	131,237.8	8.07	$/BOE

*Primary product type and all associated by-products are included

Dundee Energy Limited Partnership
NI 51-101 FORECAST CASE
RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
Canada

Effective December 31, 2017

Opening: Deloitte December 31, 2016 Forecast Pricing
Closing: Deloitte December 31, 2017 Forecast Pricing

	Light & Medium Oil			Conventional Gas			Coalbed Methane			Natural Gas Liquids		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	Mstb	Mstb	Mstb
Opening Balance	2,178.6	849.8	3,028.4	96,227.8	19,466.8	115,694.6	130.9	78.7	209.6	10.6	3.3	13.9
Production	-129.6	0.0	-129.6	-3,676.7	0.0	-3,676.7	-14.4	0.0	-14.4	-0.3	0.0	-0.3
Technical Revisions	-56.0	-49.8	-105.8	-10,094.3	-965.8	-11,060.1	-35.2	-52.2	-87.4	-2.1	-0.8	-2.9
Extensions & Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquistions	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-11.3	-5.4	-16.8	-42.4	-9.0	-51.4	-23.2	10.4	-12.9	-0.1	0.0	-0.1
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	1,981.7	794.6	2,776.3	82,414.4	18,492.0	100,906.4	58.0	36.9	94.9	8.1	2.5	10.6

Dundee Energy Limited Partnership
Economics Detail - Before Tax
Results as of January 1, 2018
Proved Developed Producing
Dundee Energy Limited Partnership

		WI Share Oil				WI Share Sales Gas				WI Share Condensate				WI Share Liquids				WI Other	
Year	WI Wells	Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	Cal Day Rate Mcf/d	Volume MMcf	Avg. Price $C/Mcf	Sales Revenue MM$C	Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	Sales Revenue MM$C	WI Sales Revenue MM$C
2018	507.12	390.6	142.6	69.21	9.9	9,722.7	3,548.8	3.88	13.8	-	-	-	-	1.2	0.5	40.79	0.0	-	23.7
2019	499.43	350.9	128.1	72.01	9.2	9,238.1	3,371.9	4.04	13.6	-	-	-	-	1.1	0.4	42.61	0.0	-	22.9
2020	470.93	311.0	113.8	74.33	8.5	8,798.1	3,220.1	4.20	13.5	-	-	-	-	1.0	0.4	44.04	0.0	-	22.0
2021	445.15	276.1	100.8	79.87	8.0	8,374.6	3,056.7	4.46	13.6	-	-	-	-	0.9	0.3	48.02	0.0	-	21.7
2022	421.47	247.1	90.2	87.80	7.9	7,970.0	2,909.1	4.67	13.6	-	-	-	-	0.9	0.3	53.91	0.0	-	21.5
2023	398.98	221.3	80.8	89.61	7.2	7,610.7	2,777.9	4.98	13.8	-	-	-	-	0.8	0.3	55.33	0.0	-	21.1
2024	378.68	197.1	72.1	91.40	6.6	7,269.2	2,660.5	5.35	14.2	-	-	-	-	0.7	0.3	56.75	0.0	-	20.8
2025	354.19	177.7	64.9	93.20	6.0	6,946.4	2,535.4	5.66	14.3	-	-	-	-	0.7	0.2	58.22	0.0	-	20.4
2026	333.01	157.9	57.7	95.04	5.5	6,639.4	2,423.4	5.87	14.2	-	-	-	-	0.6	0.2	59.71	0.0	-	19.7
2027	319.11	139.0	50.7	96.93	4.9	6,346.8	2,316.6	6.02	14.0	-	-	-	-	0.5	0.2	61.23	0.0	-	18.9
2028	301.62	124.3	45.5	98.89	4.5	6,068.6	2,221.1	6.18	13.7	-	-	-	-	0.5	0.2	62.78	0.0	-	18.2
2029	284.14	111.3	40.6	100.86	4.1	5,803.2	2,118.2	6.28	13.3	-	-	-	-	0.4	0.2	64.39	0.0	-	17.4
2030	261.92	98.2	35.9	102.86	3.7	5,550.4	2,025.9	6.44	13.0	-	-	-	-	0.4	0.1	66.06	0.0	-	16.7
2031	246.45	89.4	32.6	104.89	3.4	5,314.5	1,939.8	6.55	12.7	-	-	-	-	0.3	0.1	67.70	0.0	-	16.1
2032	233.47	79.7	29.2	106.96	3.1	5,088.8	1,862.5	6.70	12.5	-	-	-	-	0.3	0.1	69.39	0.0	-	15.6
Rem.	214.49	16.9	216.1	124.01	26.8	2,583.3	33,021.9	8.98	296.7	-	-	-	-	0.1	0.7	79.24	0.1	-	323.5
50.00 yr			**1,301.5**	**91.76**	**119.4**		**72,009.8**	**6.95**	**500.7**		**-**	**-**	**-**		**4.4**	**56.90**	**0.3**	**-**	**620.3**

	Crown Royalties			Freehold Royalties				Indian Royalties			Overriding Royalties						
Year	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Mineral Tax M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	Unadj. Royalty M$C	Royalty Deduction M$C	Royalty Payable M$C	NPI Payable M$C	Other Burdens M$C	Total Roy. & Burden M$C	Total Roy. & Burden %
2018	0.9	0.2	0.7	2,964.7	-	2,964.7	-	-	-	-	650.9	-	650.9	47.1	-	3,663.4	15.5
2019	0.9	0.2	0.7	2,864.2	-	2,864.2	-	-	-	-	627.6	-	627.6	47.7	-	3,540.2	15.5
2020	0.9	0.2	0.8	2,754.5	-	2,754.5	-	-	-	-	602.8	-	602.8	48.3	-	3,406.3	15.5
2021	0.9	0.1	0.8	2,716.4	-	2,716.4	-	-	-	-	592.4	-	592.4	50.4	-	3,360.0	15.5
2022	0.9	0.1	0.8	2,693.6	-	2,693.6	-	-	-	-	587.0	-	587.0	51.3	-	3,332.6	15.5
2023	0.9	0.1	0.8	2,640.1	-	2,640.1	-	-	-	-	572.9	-	572.9	53.6	-	3,267.4	15.5
2024	0.9	0.1	0.8	2,607.2	-	2,607.2	-	-	-	-	565.4	-	565.4	56.6	-	3,230.1	15.5
2025	0.9	0.1	0.8	2,553.8	-	2,553.8	-	-	-	-	550.3	-	550.3	58.5	-	3,163.3	15.5
2026	0.8	0.1	0.7	2,466.7	-	2,466.7	-	-	-	-	525.0	-	525.0	58.4	-	3,050.9	15.5
2027	0.8	0.1	0.7	2,363.2	-	2,363.2	-	-	-	-	500.2	-	500.2	57.8	-	2,921.9	15.5
2028	0.7	0.1	0.7	2,282.0	-	2,282.0	-	-	-	-	479.0	-	479.0	57.1	-	2,818.8	15.5
2029	0.5	0.1	0.5	2,180.3	-	2,180.3	-	-	-	-	456.2	-	456.2	55.9	-	2,692.9	15.5
2030	0.4	0.0	0.3	2,096.2	-	2,096.2	-	-	-	-	439.0	-	439.0	56.1	-	2,591.6	15.5
2031	0.4	0.0	0.3	2,018.0	-	2,018.0	-	-	-	-	422.9	-	422.9	54.9	-	2,496.1	15.5
2032	0.3	0.0	0.3	1,953.1	-	1,953.1	-	-	-	-	406.7	-	406.7	55.0	-	2,415.1	15.5
Rem.	0.0	0.0	0.0	40,466.2	-	40,466.2	-	-	-	-	7,624.7	-	7,624.7	1,438.3	-	49,529.3	15.3
50.00 yr	**11.2**	**1.6**	**9.6**	**77,620.4**	**-**	**77,620.4**	**-**	**-**	**-**	**-**	**15,602.9**	**-**	**15,602.9**	**2,247.1**	**-**	**95,480.0**	**15.4**

											Capital Costs					Before Tax Cash Flow		
Year	WI Sales Revenue MM$C	Royalty Revenue MM$C	Co. Share Revenue MM$C	Total Roy. & Burden MM$C	Net Revenue MM$C	Operating Costs MM$C	Abandon. & Salvage MM$C	Other Revenue MM$C	Sask Cap Surch MM$C	Net Op. Income MM$C	COGPE MM$C	CEE MM$C	CDE MM$C	CCA MM$C	Total MM$C	BTCF MM$C	Cum. MM$C	NPV @ 10.00 % MM$C
2018	23.7	0.0	23.7	3.7	20.0	8.8	3.0	-	-	8.2	-	-	-	-	-	8.2	8.2	7.9
2019	22.9	0.0	22.9	3.5	19.4	8.5	0.5	-	-	10.4	-	-	-	-	-	10.4	18.6	9.0
2020	22.0	0.0	22.0	3.4	18.6	8.2	3.1	-	-	7.4	-	-	-	-	-	7.4	26.0	5.8
2021	21.7	0.0	21.7	3.4	18.4	7.8	2.2	-	-	8.4	-	-	-	-	-	8.4	34.4	6.0
2022	21.5	0.0	21.5	3.3	18.2	7.5	1.0	-	-	9.8	-	-	-	-	-	9.8	44.2	6.4
2023	21.1	0.0	21.1	3.3	17.8	7.2	1.1	-	-	9.6	-	-	-	-	-	9.6	53.8	5.7
2024	20.8	0.0	20.9	3.2	17.6	6.9	1.1	-	-	9.6	-	-	-	-	-	9.6	63.4	5.2
2025	20.4	0.0	20.4	3.2	17.3	6.7	1.5	-	-	9.2	-	-	-	-	-	9.2	72.5	4.5
2026	19.7	0.0	19.7	3.1	16.7	6.4	1.0	-	-	9.3	-	-	-	-	-	9.3	81.8	4.1
2027	18.9	0.0	18.9	2.9	16.0	6.2	1.2	-	-	8.6	-	-	-	-	-	8.6	90.4	3.5
2028	18.2	0.0	18.3	2.8	15.4	5.9	2.8	-	-	6.6	-	-	-	-	-	6.6	97.1	2.4
2029	17.4	0.0	17.4	2.7	14.7	5.7	0.7	-	-	8.4	-	-	-	-	-	8.4	105.4	2.8
2030	16.7	0.0	16.8	2.6	14.2	5.4	0.7	-	-	8.0	-	-	-	-	-	8.0	113.5	2.4
2031	16.1	0.0	16.1	2.5	13.6	5.3	1.2	-	-	7.1	-	-	-	-	-	7.1	120.6	2.0
2032	15.6	0.0	15.6	2.4	13.2	5.0	0.5	-	-	7.7	-	-	-	-	-	7.7	128.3	1.9
Rem.	323.5	0.6	324.2	49.5	274.6	82.4	61.2	-	-	131.0	-	-	-	-	-	131.0	259.3	13.6
50.00 yr	**620.3**	**1.0**	**621.3**	**95.5**	**525.8**	**183.9**	**82.6**	**-**	**-**	**259.3**	**-**	**-**	**-**	**-**	**-**	**259.3**	**259.3**	**83.3**

Country/Province	Canada
Mineral Owner	N/A
Prod. Category	N/A
Incentive	N/A
Econ. Calc. Date	Jan 2017
Avg. WI Share	97.33 %
Econ. Life/To Aban.	50.00 yr / 50.00 yr
Econ. RLI	17.61 yr
Price Deck	Deloitte December 31 2017 Forecast
Price Set	N/A
Economic Limit	N/A
COS / COO	100.0 % / 100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	<multiple>

	Remaining Reserves					Net Revenue NPV (MM$C)					
Product	Gross	WI	RI	Co. Share	Net	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Oil (Mbbl)	1,395.3	1,301.5	7.4	1,308.9	1,108.6	102.0	67.8	56.4	50.7	40.7	34.1
Sales Gas (MMcf)	73,634.6	72,009.8	7.1	72,016.9	60,907.6	423.6	186.9	134.7	113.0	80.5	62.8
Condensate (Mbbl)	-	-	-	-	-	-	-	-	-	-	-
Liquids (Mbbl)	4.6	4.4	-	4.4	3.6	0.2	0.1	0.1	0.1	0.1	0.1
Other Equiv. (MBOE)	-	-	-	-	-	-	-	-	-	-	-
Other						-	-	-	-	-	-
Total (MBOE)	**13,672.3**	**13,307.5**	**8.6**	**13,316.1**	**11,263.5**	**525.8**	**254.9**	**191.2**	**163.9**	**121.3**	**96.9**
Total BTCF						**259.3**	**131.8**	**98.0**	**83.3**	**60.4**	**47.5**

Dundee Energy Limited Partnership
Economics Detail - After Tax
Results for 2018 Taxation Year
Proved Developed Producing
Dundee Energy Limited Partnership

Year	Revenue: WI Sales Revenue MM$C	Revenue: Royalty Revenue MM$C	Revenue: Other Revenue MM$C	Revenue: Total Revenue MM$C	Royalties & Expenses: Crown Royalty Payable MM$C	Royalties & Expenses: Other Royalty Payable MM$C	Royalties & Expenses: Op. Costs, Aband, Salvage & Taxes MM$C	Royalties & Expenses: Total Royalties & Expenses MM$C	Taxable Income Before Deductions MM$C	Deductions: Tax Pools Available MM$C	Deductions: Non-capital Loss Carry-forward MM$C	Deductions: Claim MM$C	Taxable Income MM$C
2018	23.7	0.0	-	23.7	0.0	3.7	11.8	15.5	8.2	34.9	-	8.2	-
2019	22.9	0.0	-	22.9	0.0	3.5	9.0	12.5	10.4	7.5	26.6	10.4	-
2020	22.0	0.0	-	22.0	0.0	3.4	11.3	14.7	7.4	6.8	23.7	7.4	-
2021	21.7	0.0	-	21.7	0.0	3.4	9.9	13.3	8.4	6.1	23.1	8.4	-
2022	21.5	0.0	-	21.5	0.0	3.3	8.4	11.8	9.8	5.5	20.8	9.8	-
2023	21.1	0.0	-	21.1	0.0	3.3	8.2	11.5	9.6	4.9	16.5	9.6	-
2024	20.8	0.0	-	20.9	0.0	3.2	8.0	11.3	9.6	4.4	11.8	9.6	-
2025	20.4	0.0	-	20.4	0.0	3.2	8.1	11.3	9.2	4.0	6.6	9.2	-
2026	19.7	0.0	-	19.7	0.0	3.1	7.4	10.4	9.3	3.6	1.5	5.1	4.2
2027	18.9	0.0	-	18.9	0.0	2.9	7.3	10.3	8.6	3.2	-	3.2	5.4
2028	18.2	0.0	-	18.3	0.0	2.8	8.8	11.6	6.6	2.9	-	2.9	3.7
2029	17.4	0.0	-	17.4	0.0	2.7	6.4	9.1	8.4	2.6	-	2.6	5.8
2030	16.7	0.0	-	16.8	0.0	2.6	6.2	8.7	8.0	2.4	-	2.4	5.7
2031	16.1	0.0	-	16.1	0.0	2.5	6.5	9.0	7.1	2.1	-	2.1	5.0
2032	15.6	0.0	-	15.6	0.0	2.4	5.5	7.9	7.7	1.9	-	1.9	5.8
Rem.	323.5	0.6	-	324.2	0.0	49.5	143.6	193.1	131.0	16.7	-	16.7	152.2
50.00 yr	**620.3**	**1.0**	**-**	**621.3**	**0.0**	**95.5**	**266.5**	**362.0**	**259.3**	**109.4**		**109.4**	**187.8**

Year	Capital Cost Allowance: Initial Balance MM$C	Capital Cost Allowance: Additions MM$C	Capital Cost Allowance: Depn. Rate %	Capital Cost Allowance: Expense Claim MM$C	Cdn. Oil & Gas Property Expense: Initial Balance MM$C	Cdn. Oil & Gas Property Expense: Additions MM$C	Cdn. Oil & Gas Property Expense: Expense Claim MM$C	Canadian Exploration Expense: Initial Balance MM$C	Canadian Exploration Expense: Additions MM$C	Canadian Exploration Expense: Expense Claim MM$C	Canadian Development Expense: Initial Balance MM$C	Canadian Development Expense: Additions MM$C	Canadian Development Expense: Expense Claim MM$C	Foreign Expl. Expense: Initial Balance MM$C	Foreign Expl. Expense: Expense Claim MM$C	COGPE, CEE, CDE, FEDE, CCA MM$C
2018	-	-	-	-	83.3	-	8.3	26.5	-	26.5	0.0	-	0.0	-	-	34.9
2019	-	-	-	-	75.0	-	7.5	-	-	-	0.0	-	0.0	-	-	7.5
2020	-	-	-	-	67.5	-	6.8	-	-	-	0.0	-	0.0	-	-	6.8
2021	-	-	-	-	60.8	-	6.1	-	-	-	0.0	-	0.0	-	-	6.1
2022	-	-	-	-	54.7	-	5.5	-	-	-	0.0	-	0.0	-	-	5.5
2023	-	-	-	-	49.2	-	4.9	-	-	-	0.0	-	0.0	-	-	4.9
2024	-	-	-	-	44.3	-	4.4	-	-	-	0.0	-	0.0	-	-	4.4
2025	-	-	-	-	39.9	-	4.0	-	-	-	0.0	-	0.0	-	-	4.0
2026	-	-	-	-	35.9	-	3.6	-	-	-	0.0	-	0.0	-	-	3.6
2027	-	-	-	-	32.3	-	3.2	-	-	-	0.0	-	0.0	-	-	3.2
2028	-	-	-	-	29.1	-	2.9	-	-	-	0.0	-	0.0	-	-	2.9
2029	-	-	-	-	26.2	-	2.6	-	-	-	0.0	-	0.0	-	-	2.6
2030	-	-	-	-	23.5	-	2.4	-	-	-	0.0	-	0.0	-	-	2.4
2031	-	-	-	-	21.2	-	2.1	-	-	-	0.0	-	0.0	-	-	2.1
2032	-	-	-	-	19.1	-	1.9	-	-	-	0.0	-	0.0	-	-	1.9
Rem.	-	-		-	17.2	-	16.7	-	-	-	0.0	-	0.0	-	-	16.7
50.00 yr		**-**		**-**		**-**	**82.9**		**-**	**26.5**		**-**	**0.0**		**-**	**109.4**

Year	Federal: Taxable Income MM$C	Federal: Tax Rate %	Federal: Tax Payable MM$C	Provincial: Taxable Income MM$C	Provincial: Tax Rate %	Provincial: Tax Payable MM$C	Cash Flow: BTCF MM$C	Cash Flow: Total Tax Payable MM$C	Cash Flow: ATCF MM$C	Cash Flow: Cum. ATCF MM$C	Cash Flow: NPV @ 10.00 % MM$C
2018	-	-	-	-	-	-	8.2	-	8.2	8.2	7.9
2019	-	-	-	-	-	-	10.4	-	10.4	18.6	9.0
2020	-	-	-	-	-	-	7.4	-	7.4	26.0	5.8
2021	-	-	-	-	-	-	8.4	-	8.4	34.4	6.0
2022	-	-	-	-	-	-	9.8	-	9.8	44.2	6.4
2023	-	-	-	-	-	-	9.6	-	9.6	53.8	5.7
2024	-	-	-	-	-	-	9.6	-	9.6	63.4	5.2
2025	-	-	-	-	-	-	9.2	-	9.2	72.5	4.5
2026	4.2	15.0	0.6	4.2	11.5	0.5	9.3	1.1	8.2	80.7	3.6
2027	5.4	15.0	0.8	5.4	11.5	0.6	8.6	1.4	7.2	87.9	2.9
2028	3.7	15.0	0.6	3.7	11.5	0.4	6.6	1.0	5.7	93.5	2.1
2029	5.8	15.0	0.9	5.8	11.5	0.7	8.4	1.5	6.8	100.4	2.3
2030	5.7	15.0	0.8	5.7	11.5	0.7	8.0	1.5	6.5	106.9	2.0
2031	5.0	15.0	0.7	5.0	11.5	0.6	7.1	1.3	5.8	112.7	1.6
2032	5.8	15.0	0.9	5.8	11.5	0.7	7.7	1.5	6.2	118.9	1.6
Rem.	152.2	15.0	22.8	152.2	11.5	17.5	131.0	40.3	90.7	209.6	10.5
50.00 yr	**187.8**	**15.0**	**28.2**	**187.8**	**11.5**	**21.6**	**259.3**	**49.8**	**209.6**	**209.6**	**77.0**

Cash Flow NPV (MM$C)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Before Tax Cash Flow	259.3	131.8	98.0	83.3	60.4	47.5
Tax Payable	49.8	15.3	8.7	6.3	3.1	1.7
After Tax Cash Flow	209.6	116.5	89.3	77.0	57.3	45.8

Dundee Energy Limited Partnership
Economics Detail - Before Tax
Results as of January 1, 2018
Total Proved
Dundee Energy Limited Partnership

Year	WI Wells	WI Share Oil: Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	WI Share Sales Gas: Cal Day Rate Mcf/d	Volume MMcf	Avg. Price $C/Mcf	Sales Revenue MM$C	WI Share Condensate: Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	WI Share Liquids: Cal Day Rate bbl/d	Volume Mbbl	Avg. Price $C/bbl	Sales Revenue MM$C	WI Other: Sales Revenue MM$C	WI Sales Revenue MM$C
2018	507.12	392.9	143.4	69.21	9.9	9,728.8	3,551.0	3.88	13.8	-	-	-	-	1.2	0.5	40.79	0.0	-	23.7
2019	500.93	419.0	152.9	71.98	11.0	10,397.4	3,795.1	4.04	15.3	-	-	-	-	1.6	0.6	42.12	0.0	-	26.4
2020	485.43	493.5	180.6	74.17	13.4	11,028.5	4,036.4	4.20	16.9	-	-	-	-	2.3	0.8	43.29	0.0	-	30.4
2021	466.15	477.3	174.2	79.63	13.9	11,287.2	4,119.8	4.46	18.4	-	-	-	-	2.2	0.8	47.50	0.0	-	32.3
2022	444.47	391.9	143.0	87.54	12.5	11,464.5	4,184.5	4.66	19.5	-	-	-	-	1.7	0.6	53.77	0.0	-	32.1
2023	421.98	336.3	122.8	89.34	11.0	10,448.8	3,813.8	4.98	19.0	-	-	-	-	1.4	0.5	55.24	0.0	-	30.0
2024	400.68	293.6	107.5	91.13	9.8	9,516.9	3,483.2	5.34	18.6	-	-	-	-	1.2	0.5	56.70	0.0	-	28.4
2025	376.19	261.5	95.5	92.92	8.9	8,782.0	3,205.4	5.66	18.1	-	-	-	-	1.1	0.4	58.20	0.0	-	27.0
2026	355.01	232.3	84.8	94.76	8.0	8,166.5	2,980.8	5.86	17.5	-	-	-	-	1.0	0.4	59.71	0.0	-	25.5
2027	341.11	205.9	75.2	96.65	7.3	7,630.4	2,785.1	6.02	16.8	-	-	-	-	0.9	0.3	61.25	0.0	-	24.1
2028	323.12	185.2	67.8	98.61	6.7	7,161.5	2,621.1	6.18	16.2	-	-	-	-	0.8	0.3	62.83	0.0	-	22.9
2029	305.64	167.3	61.1	100.57	6.1	6,742.9	2,461.2	6.28	15.5	-	-	-	-	0.7	0.2	64.47	0.0	-	21.6
2030	283.42	149.9	54.7	102.58	5.6	6,365.9	2,323.6	6.44	15.0	-	-	-	-	0.6	0.2	66.15	0.0	-	20.6
2031	267.95	137.3	50.1	104.61	5.2	6,021.7	2,197.9	6.54	14.4	-	-	-	-	0.6	0.2	67.81	0.0	-	19.6
2032	253.97	124.2	45.5	106.68	4.9	5,710.2	2,089.9	6.70	14.0	-	-	-	-	0.5	0.2	69.52	0.0	-	18.9
Rem.	233.99	33.1	422.7	129.98	54.9	2,724.2	34,823.6	8.93	310.8	-	-	-	-	0.1	1.6	89.40	0.1	-	365.9
50.00 yr			**1,981.7**	**95.44**	**189.1**		**82,472.4**	**6.79**	**559.8**		**-**	**-**	**-**		**8.1**	**60.45**	**0.5**	**-**	**749.4**

Year	Crown Royalties: Unadj. Royalty MM$C	Royalty Deduction MM$C	Royalty Payable MM$C	Freehold Royalties: Unadj. Royalty MM$C	Royalty Deduction MM$C	Royalty Payable MM$C	Mineral Tax MM$C	Indian Royalties: Unadj. Royalty MM$C	Royalty Deduction MM$C	Royalty Payable MM$C	Overriding Royalties: Unadj. Royalty MM$C	Royalty Deduction MM$C	Royalty Payable MM$C	NPI Payable MM$C	Other Burdens MM$C	Total Roy. & Burden MM$C	Total Roy. & Burden %
2018	0.0	0.0	0.0	3.0	-	3.0	-	-	-	-	0.7	-	0.7	0.0	-	3.7	15.5
2019	0.0	0.0	0.0	3.3	-	3.3	-	-	-	-	0.7	-	0.7	0.0	-	4.1	15.4
2020	0.0	0.0	0.0	3.8	-	3.8	-	-	-	-	0.9	-	0.9	0.0	-	4.7	15.6
2021	0.0	0.0	0.0	4.0	-	4.0	-	-	-	-	1.0	-	1.0	0.1	-	5.1	15.9
2022	0.0	0.0	0.0	4.0	-	4.0	-	-	-	-	1.0	-	1.0	0.1	-	5.1	15.9
2023	0.0	0.0	0.0	3.8	-	3.8	-	-	-	-	0.9	-	0.9	0.1	-	4.7	15.7
2024	0.0	0.0	0.0	3.6	-	3.6	-	-	-	-	0.9	-	0.9	0.1	-	4.5	15.7
2025	0.0	0.0	0.0	3.4	-	3.4	-	-	-	-	0.8	-	0.8	0.1	-	4.2	15.7
2026	0.0	0.0	0.0	3.2	-	3.2	-	-	-	-	0.7	-	0.7	0.1	-	4.0	15.6
2027	0.0	0.0	0.0	3.0	-	3.0	-	-	-	-	0.7	-	0.7	0.1	-	3.8	15.6
2028	0.0	0.0	0.0	2.9	-	2.9	-	-	-	-	0.6	-	0.6	0.1	-	3.6	15.6
2029	0.0	0.0	0.0	2.7	-	2.7	-	-	-	-	0.6	-	0.6	0.1	-	3.4	15.6
2030	0.0	0.0	0.0	2.6	-	2.6	-	-	-	-	0.6	-	0.6	0.1	-	3.2	15.6
2031	0.0	0.0	0.0	2.5	-	2.5	-	-	-	-	0.5	-	0.5	0.1	-	3.1	15.6
2032	0.0	0.0	0.0	2.4	-	2.4	-	-	-	-	0.5	-	0.5	0.1	-	2.9	15.6
Rem.	0.0	0.0	0.0	45.8	-	45.8	-	-	-	-	9.1	-	9.1	1.4	-	56.3	15.4
50.00 yr	**0.0**	**0.0**	**0.0**	**93.8**	**-**	**93.8**	**-**	**-**	**-**	**-**	**20.3**	**-**	**20.3**	**2.2**	**-**	**116.3**	**15.5**

Year	WI Sales Revenue MM$C	Royalty Revenue MM$C	Co. Share Revenue MM$C	Total Roy. & Burden MM$C	Net Revenue MM$C	Operating Costs MM$C	Abandon. & Salvage MM$C	Other Revenue MM$C	Sask Cap Surch MM$C	Net Op. Income MM$C	Capital Costs: COGPE MM$C	CEE MM$C	CDE MM$C	CCA MM$C	Total MM$C	Before Tax Cash Flow: BTCF MM$C	Cum. MM$C	NPV @ 10.00 % MM$C
2018	23.7	0.0	23.8	3.7	20.1	8.9	3.0	-	-	8.3	-	-	-	0.0	0.0	8.3	8.3	7.9
2019	26.4	0.0	26.4	4.1	22.3	9.0	0.5	-	-	12.9	0.0	-	7.0	1.5	8.5	4.4	12.7	3.7
2020	30.4	0.0	30.4	4.7	25.7	9.2	3.1	-	-	13.3	0.0	-	1.8	0.1	1.9	11.4	24.1	9.0
2021	32.3	0.0	32.3	5.1	27.2	9.3	2.2	-	-	15.7	-	-	3.7	0.6	4.3	11.5	35.5	8.2
2022	32.1	0.0	32.1	5.1	27.0	9.1	1.0	-	-	17.0	-	-	1.5	0.2	1.7	15.3	50.9	10.0
2023	30.0	0.0	30.0	4.7	25.3	8.5	1.1	-	-	15.7	-	-	-	-	-	15.7	66.5	9.3
2024	28.4	0.0	28.5	4.5	24.0	8.1	1.1	-	-	14.7	-	-	-	-	-	14.7	81.3	7.9
2025	27.0	0.0	27.0	4.2	22.8	7.7	1.5	-	-	13.6	-	-	-	-	-	13.6	94.9	6.7
2026	25.5	0.0	25.6	4.0	21.6	7.4	1.0	-	-	13.2	-	-	-	-	-	13.2	108.1	5.9
2027	24.1	0.0	24.1	3.8	20.3	7.1	1.2	-	-	12.1	-	-	-	-	-	12.1	120.1	4.9
2028	22.9	0.0	22.9	3.6	19.4	6.8	2.8	-	-	9.7	-	-	-	-	-	9.7	129.8	3.6
2029	21.6	0.0	21.6	3.4	18.3	6.5	0.7	-	-	11.1	-	-	-	-	-	11.1	140.9	3.7
2030	20.6	0.0	20.6	3.2	17.4	6.2	0.7	-	-	10.4	-	-	-	-	-	10.4	151.3	3.2
2031	19.6	0.0	19.7	3.1	16.6	6.1	1.3	-	-	9.2	-	-	-	-	-	9.2	160.5	2.5
2032	18.9	0.0	18.9	2.9	16.0	5.8	0.6	-	-	9.6	-	-	-	-	-	9.6	170.2	2.4
Rem.	365.9	0.6	366.5	56.3	310.2	96.0	63.5	-	-	150.7	-	-	-	-	-	150.7	320.9	16.0
50.00 yr	**749.4**	**1.0**	**750.3**	**116.3**	**634.0**	**211.8**	**85.1**	**-**	**-**	**337.2**	**0.1**	**-**	**13.9**	**2.3**	**16.3**	**320.9**	**320.9**	**104.9**

Country/Province	Canada
Mineral Owner	N/A
Prod. Category	N/A
Incentive	N/A
Econ. Calc. Date	Jan 2017
Avg. WI Share	97.14 %
Econ. Life/To Aban.	50.00 yr / 50.00 yr
Econ. RLI	20.86 yr
Price Deck	Deloitte December 31 2017 Forecast
Price Set	N/A
Economic Limit	N/A
COS / COO	100.0 % / 100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	<multiple>

Product	Remaining Reserves: Gross	WI	RI	Co. Share	Net	Net Revenue NPV (MM$C): 0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Oil (Mbbl)	2,094.0	1,981.7	7.4	1,989.1	1,680.3	160.6	100.0	81.4	72.4	56.8	46.8
Sales Gas (MMcf)	84,573.4	82,472.4	7.1	82,479.5	69,664.3	473.0	218.1	159.7	134.9	97.0	75.6
Condensate (Mbbl)	-	-	-	-	-	-	-	-	-	-	-
Liquids (Mbbl)	8.2	8.1	-	8.1	6.6	0.4	0.2	0.2	0.2	0.1	0.1
Other Equiv. (MBOE)	-	-	-	-	-	-	-	-	-	-	-
Other						-	-	-	-	-	-
Total (MBOE)	**16,197.7**	**15,735.2**	**8.6**	**15,743.8**	**13,297.6**	**634.0**	**318.3**	**241.2**	**207.5**	**153.9**	**122.5**
Total BTCF						**320.9**	**166.3**	**123.8**	**104.9**	**74.9**	**57.6**

Dundee Energy Limited Partnership
Economics Detail - After Tax
Results for 2018 Taxation Year
Total Proved
Dundee Energy Limited Partnership

	Revenue				Royalties & Expenses					Deductions			
Year	WI Sales Revenue MM$C	Royalty Revenue MM$C	Other Revenue MM$C	Total Revenue MM$C	Crown Royalty Payable MM$C	Other Royalty Payable MM$C	Op. Costs, Aband, Salvage & Taxes MM$C	Total Royalties & Expenses MM$C	Taxable Income Before Deductions MM$C	Tax Pools Available MM$C	Non-capital Loss Carry-forward MM$C	Claim MM$C	Taxable Income MM$C
2018	23.7	0.0	-	23.8	0.0	3.7	11.8	15.5	8.3	34.9	-	8.3	-
2019	26.4	0.0	-	26.4	0.0	4.1	9.5	13.5	12.9	9.8	26.6	12.9	-
2020	30.4	0.0	-	30.4	0.0	4.7	12.3	17.1	13.3	9.1	23.5	13.3	-
2021	32.3	0.0	-	32.3	0.0	5.1	11.4	16.6	15.7	8.9	19.2	15.7	-
2022	32.1	0.0	-	32.1	0.0	5.1	10.0	15.1	17.0	8.0	12.4	17.0	-
2023	30.0	0.0	-	30.0	0.0	4.7	9.6	14.3	15.7	6.7	3.4	10.1	5.5
2024	28.4	0.0	-	28.5	0.0	4.5	9.2	13.7	14.7	5.7	-	5.7	9.0
2025	27.0	0.0	-	27.0	0.0	4.2	9.2	13.4	13.6	4.9	-	4.9	8.7
2026	25.5	0.0	-	25.6	0.0	4.0	8.4	12.4	13.2	4.2	-	4.2	8.9
2027	24.1	0.0	-	24.1	0.0	3.8	8.3	12.0	12.1	3.7	-	3.7	8.4
2028	22.9	0.0	-	22.9	0.0	3.6	9.7	13.2	9.7	3.2	-	3.2	6.4
2029	21.6	0.0	-	21.6	0.0	3.4	7.2	10.6	11.1	2.8	-	2.8	8.2
2030	20.6	0.0	-	20.6	0.0	3.2	7.0	10.2	10.4	2.5	-	2.5	7.9
2031	19.6	0.0	-	19.7	0.0	3.1	7.4	10.4	9.2	2.2	-	2.2	7.0
2032	18.9	0.0	-	18.9	0.0	2.9	6.3	9.3	9.6	2.0	-	2.0	7.6
Rem.	365.9	0.6	-	366.5	0.0	56.3	159.5	215.9	150.7	17.0	-	17.0	172.0
50.00 yr	**749.4**	**1.0**	**-**	**750.3**	**0.0**	**116.3**	**296.9**	**413.2**	**337.2**	**125.7**		**125.7**	**249.8**

	Capital Cost Allowance				Cdn. Oil & Gas Property Expense			Canadian Exploration Expense			Canadian Development Expense			Foreign Expl. Expense		
Year	Initial Balance MM$C	Additions MM$C	Depn. Rate %	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Expense Claim MM$C	COGPE, CEE, CDE, FEDE, CCA MM$C
2018	-	0.0	12.5	0.0	83.3	-	8.3	26.5	-	26.5	0.0	-	0.0	-	-	34.9
2019	0.0	1.5	11.9	0.2	75.0	0.0	7.5	-	-	-	0.0	7.0	2.1	-	-	9.8
2020	1.3	0.1	21.8	0.3	67.5	0.0	6.8	-	-	-	4.9	1.8	2.0	-	-	9.1
2021	1.1	0.6	18.2	0.3	60.8	-	6.1	-	-	-	4.7	3.7	2.5	-	-	8.9
2022	1.4	0.2	21.1	0.3	54.7	-	5.5	-	-	-	5.8	1.5	2.2	-	-	8.0
2023	1.2	-	21.8	0.3	49.2	-	4.9	-	-	-	5.1	-	1.5	-	-	6.7
2024	0.9	-	21.1	0.2	44.3	-	4.4	-	-	-	3.6	-	1.1	-	-	5.7
2025	0.7	-	20.3	0.2	39.9	-	4.0	-	-	-	2.5	-	0.8	-	-	4.9
2026	0.6	-	19.3	0.1	35.9	-	3.6	-	-	-	1.8	-	0.5	-	-	4.2
2027	0.5	-	18.2	0.1	32.3	-	3.2	-	-	-	1.2	-	0.4	-	-	3.7
2028	0.4	-	17.1	0.1	29.1	-	2.9	-	-	-	0.9	-	0.3	-	-	3.2
2029	0.3	-	15.8	0.1	26.2	-	2.6	-	-	-	0.6	-	0.2	-	-	2.8
2030	0.3	-	14.5	0.0	23.6	-	2.4	-	-	-	0.4	-	0.1	-	-	2.5
2031	0.2	-	13.2	0.0	21.2	-	2.1	-	-	-	0.3	-	0.1	-	-	2.2
2032	0.2	-	12.0	0.0	19.1	-	1.9	-	-	-	0.2	-	0.1	-	-	2.0
Rem.	0.2	-		0.1	17.2	-	16.7	-	-	-	0.1	-	0.1	-	-	17.0
50.00 yr		**2.3**		**2.3**		**0.1**	**83.0**		**-**	**26.5**		**13.9**	**13.9**		**-**	**125.7**

	Federal			Provincial			Cash Flow				
Year	Taxable Income MM$C	Tax Rate %	Tax Payable MM$C	Taxable Income MM$C	Tax Rate %	Tax Payable MM$C	BTCF MM$C	Total Tax Payable MM$C	ATCF MM$C	Cum. ATCF MM$C	NPV @ 10.00 % MM$C
2018	-	-	-	-	-	-	8.3	-	8.3	8.3	7.9
2019	-	-	-	-	-	-	4.4	-	4.4	12.7	3.7
2020	-	-	-	-	-	-	11.4	-	11.4	24.1	9.0
2021	-	-	-	-	-	-	11.5	-	11.5	35.5	8.2
2022	-	-	-	-	-	-	15.3	-	15.3	50.9	10.0
2023	5.5	15.0	0.8	5.5	11.5	0.6	15.7	1.5	14.2	65.1	8.4
2024	9.0	15.0	1.4	9.0	11.5	1.0	14.7	2.4	12.4	77.4	6.7
2025	8.7	15.0	1.3	8.7	11.5	1.0	13.6	2.3	11.3	88.7	5.5
2026	8.9	15.0	1.3	8.9	11.5	1.0	13.2	2.4	10.8	99.5	4.8
2027	8.4	15.0	1.3	8.4	11.5	1.0	12.1	2.2	9.8	109.4	4.0
2028	6.4	15.0	1.0	6.4	11.5	0.7	9.7	1.7	8.0	117.3	2.9
2029	8.2	15.0	1.2	8.2	11.5	0.9	11.1	2.2	8.9	126.2	3.0
2030	7.9	15.0	1.2	7.9	11.5	0.9	10.4	2.1	8.3	134.6	2.5
2031	7.0	15.0	1.0	7.0	11.5	0.8	9.2	1.8	7.4	142.0	2.0
2032	7.6	15.0	1.1	7.6	11.5	0.9	9.6	2.0	7.6	149.6	1.9
Rem.	172.0	15.0	25.8	172.0	11.5	19.8	150.7	45.6	105.1	254.6	12.3
50.00 yr	**249.8**	**15.0**	**37.5**	**249.8**	**11.5**	**28.7**	**320.9**	**66.2**	**254.6**	**254.6**	**92.9**

	Cash Flow NPV (MM$C)					
	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Before Tax Cash Flow	320.9	166.3	123.8	104.9	74.9	57.6
Tax Payable	66.2	24.4	15.6	12.0	6.9	4.4
After Tax Cash Flow	254.6	141.8	108.2	92.9	68.0	53.2

Dundee Energy Limited Partnership

Economics Detail - Before Tax
Results as of January 1, 2018
Total Proved + Probable
Dundee Energy Limited Partnership

Year	WI Wells	WI Share Oil Cal Day Rate bbl/d	WI Share Oil Volume Mbbl	WI Share Oil Avg. Price $C/bbl	WI Share Oil Sales Revenue MM$C	WI Share Sales Gas Cal Day Rate Mcf/d	WI Share Sales Gas Volume Bcf	WI Share Sales Gas Avg. Price $C/Mcf	WI Share Sales Gas Sales Revenue MM$C	WI Share Condensate Cal Day Rate bbl/d	WI Share Condensate Volume Mbbl	WI Share Condensate Avg. Price $C/bbl	WI Share Condensate Sales Revenue MM$C	WI Share Liquids Cal Day Rate bbl/d	WI Share Liquids Volume Mbbl	WI Share Liquids Avg. Price $C/bbl	WI Share Liquids Sales Revenue MM$C	WI Other Sales Revenue MM$C	WI Sales Revenue MM$C
2018	503.12	407.0	148.6	69.23	10.3	9,785.8	3.6	3.88	13.9	-	-	-	-	1.3	0.5	40.79	0.0	-	24.2
2019	498.93	452.4	165.1	71.99	11.9	10,718.1	3.9	4.04	15.8	-	-	-	-	1.7	0.6	42.12	0.0	-	27.7
2020	492.25	554.0	202.8	74.19	15.0	12,151.2	4.4	4.20	18.7	-	-	-	-	2.5	0.9	43.28	0.0	-	33.7
2021	480.98	553.5	202.0	79.66	16.1	13,218.2	4.8	4.46	21.5	-	-	-	-	2.5	0.9	47.50	0.0	-	37.6
2022	464.30	469.1	171.2	87.57	15.0	13,751.4	5.0	4.66	23.4	-	-	-	-	2.0	0.7	53.77	0.0	-	38.4
2023	445.80	414.1	151.1	89.37	13.5	12,482.7	4.6	4.98	22.7	-	-	-	-	1.7	0.6	55.24	0.0	-	36.2
2024	424.68	371.6	136.0	91.18	12.4	11,367.7	4.2	5.34	22.2	-	-	-	-	1.5	0.5	56.70	0.0	-	34.7
2025	400.19	337.2	123.1	93.00	11.4	10,488.5	3.8	5.65	21.6	-	-	-	-	1.3	0.5	58.20	0.0	-	33.1
2026	379.01	309.2	112.9	94.87	10.7	9,767.9	3.6	5.86	20.9	-	-	-	-	1.2	0.4	59.71	0.0	-	31.6
2027	369.11	287.2	104.8	96.80	10.1	9,151.8	3.3	6.02	20.1	-	-	-	-	1.1	0.4	61.25	0.0	-	30.3
2028	356.62	265.6	97.2	98.77	9.6	8,606.7	3.2	6.18	19.5	-	-	-	-	1.0	0.4	62.82	0.0	-	29.1
2029	333.14	242.6	88.6	100.74	8.9	8,117.4	3.0	6.28	18.6	-	-	-	-	0.9	0.3	64.44	0.0	-	27.6
2030	313.17	224.6	82.0	102.77	8.4	7,688.7	2.8	6.44	18.1	-	-	-	-	0.9	0.3	66.10	0.0	-	26.5
2031	296.70	209.0	76.3	104.80	8.0	7,297.2	2.7	6.54	17.4	-	-	-	-	0.8	0.3	67.75	0.0	-	25.4
2032	283.72	195.9	71.7	106.90	7.7	6,933.1	2.5	6.70	17.0	-	-	-	-	0.8	0.3	69.45	0.0	-	24.7
Rem.	268.24	65.9	843.0	135.07	113.9	3,571.5	45.7	9.04	412.5	-	-	-	-	0.2	3.0	90.61	0.3	-	526.7
50.00 yr			**2,776.3**	**101.93**	**283.0**		**101.0**	**6.97**	**703.9**		**-**	**-**	**-**		**10.6**	**64.27**	**0.7**	**-**	**987.5**

Year	Crown Royalties Unadj. Royalty MM$C	Crown Royalties Royalty Deduction MM$C	Crown Royalties Royalty Payable MM$C	Freehold Royalties Unadj. Royalty MM$C	Freehold Royalties Royalty Deduction MM$C	Freehold Royalties Royalty Payable MM$C	Freehold Royalties Mineral Tax MM$C	Indian Royalties Unadj. Royalty MM$C	Indian Royalties Royalty Deduction MM$C	Indian Royalties Royalty Payable MM$C	Overriding Royalties Unadj. Royalty MM$C	Overriding Royalties Royalty Deduction MM$C	Overriding Royalties Royalty Payable MM$C	NPI Payable MM$C	Other Burdens MM$C	Total Roy. & Burden MM$C	Total Roy. & Burden %
2018	0.0	0.0	0.0	3.0	-	3.0	-	-	-	-	0.7	-	0.7	0.0	-	3.7	15.4
2019	0.0	0.0	0.0	3.5	-	3.5	-	-	-	-	0.7	-	0.7	0.0	-	4.3	15.4
2020	0.0	0.0	0.0	4.2	-	4.2	-	-	-	-	1.0	-	1.0	0.0	-	5.3	15.6
2021	0.0	0.0	0.0	4.7	-	4.7	-	-	-	-	1.3	-	1.3	0.1	-	6.0	16.0
2022	0.0	0.0	0.0	4.8	-	4.8	-	-	-	-	1.3	-	1.3	0.1	-	6.1	16.0
2023	0.0	0.0	0.0	4.5	-	4.5	-	-	-	-	1.1	-	1.1	0.1	-	5.7	15.8
2024	0.0	0.0	0.0	4.3	-	4.3	-	-	-	-	1.1	-	1.1	0.1	-	5.5	15.8
2025	0.0	0.0	0.0	4.1	-	4.1	-	-	-	-	1.0	-	1.0	0.1	-	5.2	15.7
2026	0.0	0.0	0.0	4.0	-	4.0	-	-	-	-	1.0	-	1.0	0.1	-	5.0	15.7
2027	0.0	0.0	0.0	3.8	-	3.8	-	-	-	-	0.9	-	0.9	0.1	-	4.8	15.7
2028	0.0	0.0	0.0	3.6	-	3.6	-	-	-	-	0.9	-	0.9	0.1	-	4.6	15.7
2029	0.0	0.0	0.0	3.4	-	3.4	-	-	-	-	0.8	-	0.8	0.1	-	4.3	15.7
2030	0.0	0.0	0.0	3.3	-	3.3	-	-	-	-	0.8	-	0.8	0.1	-	4.1	15.6
2031	0.0	0.0	0.0	3.2	-	3.2	-	-	-	-	0.7	-	0.7	0.1	-	4.0	15.6
2032	0.0	0.0	0.0	3.1	-	3.1	-	-	-	-	0.7	-	0.7	0.1	-	3.8	15.6
Rem.	0.0	0.0	0.0	65.9	-	65.9	-	-	-	-	13.9	-	13.9	1.8	-	81.6	15.5
50.00 yr	**0.0**	**0.0**	**0.0**	**123.6**	**-**	**123.6**	**-**	**-**	**-**	**-**	**27.8**	**-**	**27.8**	**2.6**	**-**	**154.0**	**15.6**

Year	WI Sales Revenue MM$C	Royalty Revenue MM$C	Co. Share Revenue MM$C	Total Roy. & Burden MM$C	Net Revenue MM$C	Operating Costs MM$C	Abandon. & Salvage MM$C	Other Revenue MM$C	Sask Cap Surch MM$C	Net Op. Income MM$C	Capital Costs COGPE MM$C	Capital Costs CEE MM$C	Capital Costs CDE MM$C	Capital Costs CCA MM$C	Capital Costs Total MM$C	Before Tax Cash Flow BTCF MM$C	Before Tax Cash Flow Cum. MM$C	Before Tax Cash Flow NPV @ 10.00 % MM$C
2018	24.2	0.0	24.2	3.7	20.5	8.9	3.0	-	-	8.6	-	-	0.1	0.0	0.1	8.5	8.5	8.1
2019	27.7	0.0	27.7	4.3	23.5	9.2	0.5	-	-	13.8	0.0	-	7.8	1.6	9.5	4.4	12.9	3.7
2020	33.7	0.0	33.8	5.3	28.5	9.9	3.1	-	-	15.5	0.0	-	3.3	0.4	3.7	11.8	24.7	9.3
2021	37.6	0.0	37.7	6.0	31.6	10.3	2.1	-	-	19.2	-	-	5.2	0.8	6.0	13.2	37.9	9.5
2022	38.4	0.0	38.5	6.1	32.3	10.4	1.1	-	-	20.8	-	-	1.5	0.2	1.7	19.2	57.1	12.5
2023	36.2	0.0	36.2	5.7	30.5	9.9	1.1	-	-	19.5	-	-	-	-	-	19.5	76.6	11.6
2024	34.7	0.0	34.7	5.5	29.2	9.4	1.4	-	-	18.4	-	-	-	-	-	18.4	95.1	9.9
2025	33.1	0.0	33.1	5.2	27.9	9.0	1.6	-	-	17.3	-	-	-	-	-	17.3	112.4	8.5
2026	31.6	0.0	31.7	5.0	26.7	8.8	0.7	-	-	17.2	-	-	-	-	-	17.2	129.6	7.7
2027	30.3	0.0	30.3	4.8	25.6	8.6	1.3	-	-	15.7	-	-	-	-	-	15.7	145.3	6.4
2028	29.1	0.0	29.1	4.6	24.5	8.3	2.4	-	-	13.9	-	-	-	-	-	13.9	159.1	5.1
2029	27.6	0.0	27.6	4.3	23.3	7.9	0.6	-	-	14.7	-	-	-	-	-	14.7	173.9	4.9
2030	26.5	0.0	26.5	4.1	22.4	7.7	0.8	-	-	13.9	-	-	-	-	-	13.9	187.8	4.2
2031	25.4	0.0	25.5	4.0	21.5	7.5	1.3	-	-	12.7	-	-	-	-	-	12.7	200.5	3.5
2032	24.7	0.0	24.7	3.8	20.9	7.3	0.5	-	-	13.1	-	-	-	-	-	13.1	213.6	3.3
Rem.	526.7	0.8	527.4	81.6	445.8	138.9	64.7	-	-	242.2	-	-	-	-	-	242.2	455.8	23.1
50.00 yr	**987.5**	**1.2**	**988.7**	**154.0**	**834.7**	**271.9**	**86.0**	**-**	**-**	**476.7**	**0.1**	**-**	**17.9**	**3.0**	**20.9**	**455.8**	**455.8**	**131.2**

Country/Province	Canada
Mineral Owner	N/A
Prod. Category	N/A
Incentive	N/A
Econ. Calc. Date	Jan 2017
Avg. WI Share	97.21 %
Econ. Life/To Aban.	50.00 yr / 50.00 yr
Econ. RLI	25.81 yr
Price Deck	Deloitte December 31 2017 Forecast
Price Set	N/A
Economic Limit	N/A
COS / COO	100.0 % / 100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	<multiple>

Product	Remaining Reserves Gross	Remaining Reserves WI	Remaining Reserves RI	Remaining Reserves Co. Share	Remaining Reserves Net	Net Revenue NPV (MM$C) 0.00 %	Net Revenue NPV (MM$C) 5.00 %	Net Revenue NPV (MM$C) 8.00 %	Net Revenue NPV (MM$C) 10.00 %	Net Revenue NPV (MM$C) 15.00 %	Net Revenue NPV (MM$C) 20.00 %
Oil (Mbbl)	2,923.4	2,776.3	8.9	2,785.1	2,355.9	240.4	133.3	104.1	90.8	68.8	55.4
Sales Gas (Bcf)	103.5	101.0	0.0	101.0	85.2	593.7	261.5	188.1	157.6	111.4	85.8
Condensate (Mbbl)	-	-	-	-	-	-	-	-	-	-	-
Liquids (Mbbl)	10.8	10.6	-	10.6	8.6	0.6	0.3	0.2	0.2	0.2	0.1
Other Equiv. (MBOE)	-	-	-	-	-	-	-	-	-	-	-
Other						-	-	-	-	-	-
Total (MBOE)	**20,183.9**	**19,620.4**	**10.1**	**19,630.6**	**16,557.8**	**834.7**	**395.1**	**292.5**	**248.6**	**180.3**	**141.3**
Total BTCF						**455.8**	**217.0**	**157.1**	**131.2**	**91.1**	**68.6**

Dundee Energy Limited Partnership

Economics Detail - After Tax

Results for 2018 Taxation Year

Total Proved + Probable

Dundee Energy Limited Partnership

	Revenue				Royalties & Expenses					Deductions			
Year	WI Sales Revenue MM$C	Royalty Revenue MM$C	Other Revenue MM$C	Total Revenue MM$C	Crown Royalty Payable MM$C	Other Royalty Payable MM$C	Op. Costs, Aband, Salvage & Taxes MM$C	Total Royalties & Expenses MM$C	Taxable Income Before Deductions MM$C	Tax Pools Available MM$C	Non-capital Loss Carry-forward MM$C	Claim MM$C	Taxable Income MM$C
2018	24.2	0.0	-	24.2	0.0	3.7	11.8	15.6	8.6	34.9	-	8.6	-
2019	27.7	0.0	-	27.7	0.0	4.3	9.7	13.9	13.8	10.1	26.3	13.8	-
2020	33.7	0.0	-	33.8	0.0	5.3	13.0	18.2	15.5	9.8	22.5	15.5	-
2021	37.6	0.0	-	37.7	0.0	6.0	12.4	18.4	19.2	9.9	16.8	19.2	-
2022	38.4	0.0	-	38.5	0.0	6.1	11.5	17.6	20.8	8.7	7.4	16.2	4.6
2023	36.2	0.0	-	36.2	0.0	5.7	11.0	16.7	19.5	7.3	-	7.3	12.3
2024	34.7	0.0	-	34.7	0.0	5.5	10.8	16.3	18.4	6.1	-	6.1	12.3
2025	33.1	0.0	-	33.1	0.0	5.2	10.6	15.8	17.3	5.2	-	5.2	12.1
2026	31.6	0.0	-	31.7	0.0	5.0	9.5	14.5	17.2	4.4	-	4.4	12.8
2027	30.3	0.0	-	30.3	0.0	4.7	9.9	14.6	15.7	3.8	-	3.8	11.9
2028	29.1	0.0	-	29.1	0.0	4.6	10.7	15.2	13.9	3.3	-	3.3	10.5
2029	27.6	0.0	-	27.6	0.0	4.3	8.5	12.8	14.7	2.9	-	2.9	11.8
2030	26.5	0.0	-	26.5	0.0	4.1	8.5	12.6	13.9	2.6	-	2.6	11.4
2031	25.4	0.0	-	25.5	0.0	4.0	8.8	12.8	12.7	2.3	-	2.3	10.4
2032	24.7	0.0	-	24.7	0.0	3.8	7.7	11.6	13.1	2.0	-	2.0	11.1
Rem.	526.7	0.8	-	527.4	0.0	81.6	203.6	285.2	242.2	17.1	-	17.0	263.3
50.00 yr	**987.5**	**1.2**	**-**	**988.7**	**0.0**	**154.0**	**357.9**	**511.9**	**476.7**	**130.3**		**130.3**	**384.6**

	Capital Cost Allowance				Cdn. Oil & Gas Property Expense			Canadian Exploration Expense			Canadian Development Expense			Foreign Expl. Expense		
Year	Initial Balance MM$C	Additions MM$C	Depn. Rate %	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Additions MM$C	Expense Claim MM$C	Initial Balance MM$C	Expense Claim MM$C	COGPE, CEE, CDE, FEDE, CCA MM$C
2018	-	0.0	12.5	0.0	83.3	-	8.3	26.5	-	26.5	0.0	0.1	0.0	-	-	34.9
2019	0.0	1.6	11.9	0.2	75.0	0.0	7.5	-	-	-	0.1	7.8	2.4	-	-	10.1
2020	1.4	0.4	20.5	0.4	67.5	0.0	6.8	-	-	-	5.5	3.3	2.6	-	-	9.8
2021	1.5	0.8	18.8	0.4	60.8	-	6.1	-	-	-	6.2	5.2	3.4	-	-	9.9
2022	1.8	0.2	22.0	0.4	54.7	-	5.5	-	-	-	8.0	1.5	2.8	-	-	8.7
2023	1.6	-	22.6	0.3	49.2	-	4.9	-	-	-	6.6	-	2.0	-	-	7.3
2024	1.2	-	22.0	0.3	44.3	-	4.4	-	-	-	4.6	-	1.4	-	-	6.1
2025	0.9	-	21.3	0.2	39.9	-	4.0	-	-	-	3.2	-	1.0	-	-	5.2
2026	0.7	-	20.4	0.2	35.9	-	3.6	-	-	-	2.3	-	0.7	-	-	4.4
2027	0.6	-	19.5	0.1	32.3	-	3.2	-	-	-	1.6	-	0.5	-	-	3.8
2028	0.5	-	18.4	0.1	29.1	-	2.9	-	-	-	1.1	-	0.3	-	-	3.3
2029	0.4	-	17.3	0.1	26.2	-	2.6	-	-	-	0.8	-	0.2	-	-	2.9
2030	0.3	-	16.0	0.1	23.6	-	2.4	-	-	-	0.5	-	0.2	-	-	2.6
2031	0.3	-	14.8	0.0	21.2	-	2.1	-	-	-	0.4	-	0.1	-	-	2.3
2032	0.2	-	13.5	0.0	19.1	-	1.9	-	-	-	0.3	-	0.1	-	-	2.0
Rem.	0.2	-		0.2	17.2	-	16.7	-	-	-	0.2	-	0.2	-	-	17.1
50.00 yr		**3.0**		**3.0**		**0.1**	**83.0**		**-**	**26.5**		**17.9**	**17.9**		**-**	**130.3**

	Federal			Provincial			Cash Flow				
Year	Taxable Income MM$C	Tax Rate %	Tax Payable MM$C	Taxable Income MM$C	Tax Rate %	Tax Payable MM$C	BTCF MM$C	Total Tax Payable MM$C	ATCF MM$C	Cum. ATCF MM$C	NPV @ 10.00 % MM$C
2018	-	-	-	-	-	-	8.5	-	8.5	8.5	8.1
2019	-	-	-	-	-	-	4.4	-	4.4	12.9	3.7
2020	-	-	-	-	-	-	11.8	-	11.8	24.7	9.3
2021	-	-	-	-	-	-	13.2	-	13.2	37.9	9.5
2022	4.6	15.0	0.7	4.6	11.5	0.5	19.2	1.2	18.0	55.9	11.7
2023	12.3	15.0	1.8	12.3	11.5	1.4	19.5	3.3	16.3	72.1	9.7
2024	12.3	15.0	1.9	12.3	11.5	1.4	18.4	3.3	15.2	87.3	8.2
2025	12.1	15.0	1.8	12.1	11.5	1.4	17.3	3.2	14.1	101.4	6.9
2026	12.8	15.0	1.9	12.8	11.5	1.5	17.2	3.4	13.8	115.2	6.2
2027	11.9	15.0	1.8	11.9	11.5	1.4	15.7	3.1	12.5	127.8	5.1
2028	10.5	15.0	1.6	10.5	11.5	1.2	13.9	2.8	11.1	138.8	4.1
2029	11.8	15.0	1.8	11.8	11.5	1.4	14.7	3.1	11.6	150.4	3.9
2030	11.4	15.0	1.7	11.4	11.5	1.3	13.9	3.0	10.9	161.4	3.3
2031	10.4	15.0	1.6	10.4	11.5	1.2	12.7	2.8	9.9	171.3	2.7
2032	11.1	15.0	1.7	11.1	11.5	1.3	13.1	2.9	10.2	181.5	2.6
Rem.	263.3	15.0	39.5	263.3	11.5	30.3	242.2	69.8	172.4	353.9	17.5
50.00 yr	**384.6**	**15.0**	**57.7**	**384.6**	**11.5**	**44.2**	**455.8**	**101.9**	**353.9**	**353.9**	**112.3**

Cash Flow NPV (MM$C)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
Before Tax Cash Flow	455.8	217.0	157.1	131.2	91.1	68.6
Tax Payable	101.9	37.9	24.4	19.0	11.2	7.3
After Tax Cash Flow	353.9	179.2	132.7	112.3	79.9	61.4

Evaluation procedure

Definitions and methodology

Effective as of December 2017

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Procedure

Deloitte has prepared estimates of resources and reserves in accordance with the process published in The Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1, 2nd Edition. The reader is referred to the Handbook for a complete description of the particular process quoted as follows.

Resources or reserves evaluation

A "Resources or Reserves evaluation" is the process whereby a qualified reserves evaluator estimates the quantities and values of oil and gas resources or reserves by interpreting and assessing all available pertinent data. The value of an oil and gas asset is a function of the ability or potential ability of that asset to generate future net revenue, and it is measured using a set of forward-looking assumptions regarding resources or reserves, production, prices, and costs. Evaluations of oil and gas assets, in particular reserves, include a discounted cash flow analysis of estimated future net revenue.

Reserves audit

A "Reserves audit" is the process carried out by a qualified reserves auditor that results in a reasonable assurance, in the form of an opinion, that the reserves information has in all material respects been determined and presented according to the principles and definitions adopted by the Society of Petroleum Evaluation Engineers (SPEE) (Calgary Chapter), and Association of Professional Engineers and Geoscientists of Alberta (APEGA) and are, therefore free of material mis-statement.

The reserves evaluations prepared by the company have been audited, not for the purpose of verifying exactness, but the reserves information, company policies, procedures, and methods used in estimating the reserves will be examined in sufficient detail so that Deloitte can express an opinion as to whether, in the aggregate, the reserves information presented by the company are reasonable.

Deloitte may require its own independent evaluation of the reserves information for a small number of properties, or for a large number of properties as tests for the reasonableness of the company's evaluations. The tests to be applied to the company's evaluations insofar as their methods and controls and the properties selected to be re-evaluated will be determined by Deloitte, in its sole judgment, to arrive at an opinion as to the reasonableness of the company's evaluations.

Reserves review

A "Reserves review" is the process whereby a reserves auditor conducts a high-level assessment of reserves information to determine if it is plausible. The steps consist primarily of enquiry, analytical procedure, analysis, review of historical reserves performance, and discussion with the company's reserves management staff.

"Plausible" means the reserves data appear to be worthy of belief based on the information obtained by the independent qualified reserves auditor in carrying out the aforementioned steps. Negative assurance can be given by the independent reserves auditor, but an opinion cannot. For example, "Nothing came to my attention that would indicate the reserves information has not been prepared and presented in accordance with principles and definitions adopted by the SPEE (Calgary Chapter), and APEGA (Practice Standard for the Evaluation of Oil and Gas Reserves for Public Disclosure).

Reviews do not require examination of the detailed document that supports the reserves information, unless this information does not appear to be plausible.

Resource and reserve definitions

Resource classification

Resources and reserves in this evaluation are classified by Deloitte in accordance with the definitions in Volume 1, Section 5 of the Canadian Oil and Gas Evaluation Handbook, Second Edition.

The term "resources" encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, total resources are equivalent to total petroleum-initially-in-place ("PIIP").

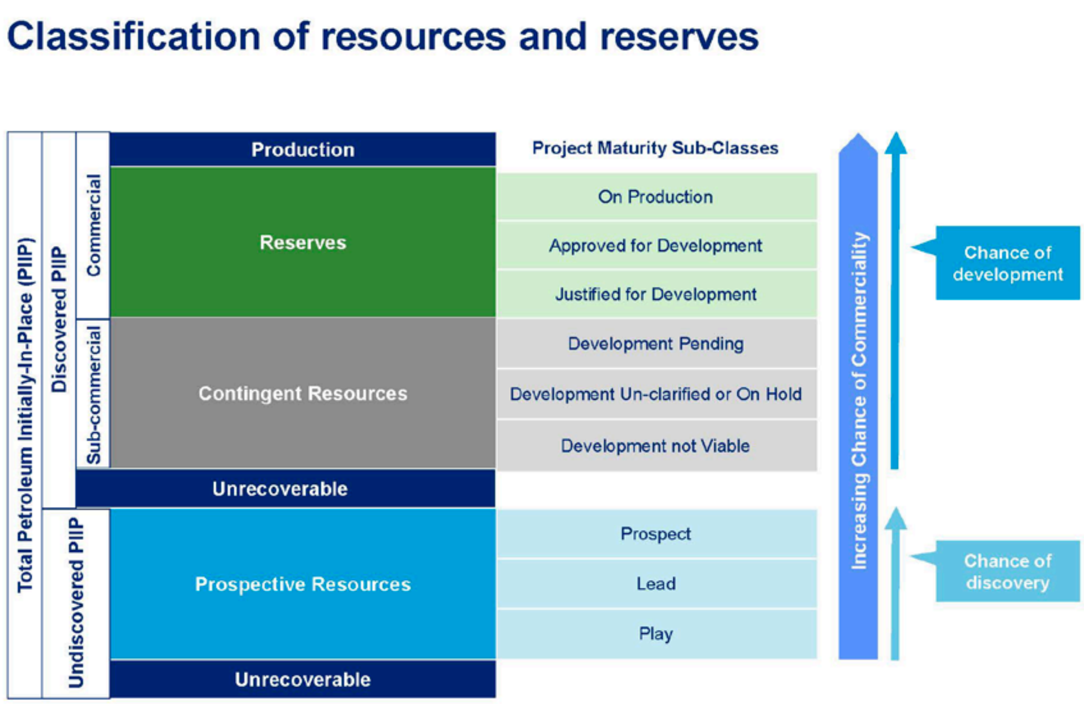

Image adapted from: SPE-PRMS, 2007

Total petroleum-initially-in-place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Discovered petroleum-initially-in-place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum-initially-in-place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Production is the cumulative quantity of petroleum that has been recovered at a given date.

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: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on development and production status. Refer to the full definitions on reserves in Section 5.4 of COGEH.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Refer to COGEH and Figure 5-1.

Unrecoverable is that portion of discovered and undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered petroleum-initially-in-place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum-initially-in-place is referred to as prospective resources; the remainder as unrecoverable.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Refer to COGEH and Figure 5-1.

Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in criteria associated with their classification. For example, the sum of reserves, contingent resources, and prospective resources may be referred to as remaining recoverable resources. When resources categories are combined, it is important that each component of the summation also be provided, and it should be made clear whether and how the components in the summation were adjusted for risk.

Uncertainty ranges

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.

Best estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.

High estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

Assessing commerciality

In order to assign recoverable resources of any category, a development plan consisting of one or more projects needs to be defined. In-place quantities for which a feasible project cannot be defined using established technology or technology under development are classified as unrecoverable. In this context "technology under development" refers to technology that has been developed and verified by testing as feasible for future commercial applications to the subject reservoir. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. In most cases recovery efficiency will be largely based on analogous projects.

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality". The chance of commerciality varies in different categories of recoverable resources as follows:

> **Reserves**: To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.
>
> **Contingent resources:** Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development". For contingent resources the chance of commerciality is equal to the chance of development.
>
> **Prospective Resources:** Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery". Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components – the chance of discovery and the chance of development.

Economic status

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to sub-classify contingent resources by economic status.

> **Economic contingent resources** are those contingent resources that are currently economically recoverable.
>
> **Sub-economic contingent resources** are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is "undetermined" (i.e., "contingent resources – economic status undetermined").

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e. specified economic conditions, which are generally accepted as being reasonable (refer to COGEH Volume 2, Section 5.8).

Reserve categories

Reserves are classified by Deloitte in accordance with the following definitions published by COGEH and which meet the standards established by National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities and found in Appendix 1 to Companion Policy 51-101 CP, Part 2 Definition of Reserves.

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:

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

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

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

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and production status

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

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

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

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of certainty for reported reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest – level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Resource and reserve estimation

Deloitte generally assigns reserves to properties via deterministic methods. Probabilistic estimation techniques are typically used where there is a low degree of certainty in the information available and is generally used in resource evaluations. This will be stated within the detailed property reports.

Deterministic

Reserves and resources were estimated either by i) volumetric, ii) decline curve analysis, iii) material balance techniques, or iv) performance predictions.

Volumetric reserves were estimated using the wellbore net pay and an assigned drainage area or, where sufficient data was available, the reservoir volumes calculated from isopach maps. Reservoir rock and fluid data were obtained from available core analysis, well logs, PVT data, gas analysis, government sources, and other published information either on the evaluated pool or from a similar reservoir in the immediate area. In mature (producing) reservoirs decline curve analysis and/or material balance was utilized in all applicable evaluations.

Probabilistic

Because of the uncertainty inherent in reservoir parameters, probabilistic analysis, which is based on statistical techniques, provides a formulated approach by which to obtain a reasonable assessment of the petroleum-initially in place (PIIP) and/or the recoverable resource. Probabilistic analysis involves generating a range of possible outcomes for each unknown parameter and their associated probability of occurrence. When probabilistic analysis is applied to resource estimation, it provides a range of possible PIIPs or recoverable resources.

In preparing a resource estimate, Deloitte assesses the following volumetric parameters: areal extent, net pay thickness, porosity, hydrocarbon saturation, reservoir temperature, reservoir pressure, gas compressibility factor, recovery factor, and surface loss. A team of professional engineers and geologists experienced in probabilistic resource evaluation considers each of the parameters individually to estimate the most reasonable range of values. Working from existing data, the team discusses and agrees on the low (P_{90}) and high (P_{10}) values for each parameter. To help test the reasonableness of the proposed range, a minimum (P_{99}) and maximum (P_1) value are also extrapolated from the low and high values. After ranges have been established for each parameter, these independent distributions are used to determine a P_{90}, P_{50}, and P_{10} result which comprise Deloitte’s estimated range of PIIP or recoverable resource.

It is important to note that the process used to determine the final P_{10}, P_{90}, and P_{50} results involves multiplying the various volumetric parameters together. This yields results which require adjustments to maintain an appropriate probability of occurrence. For example, when calculating total reservoir volume (Area x Pay), the chance of getting a volume greater than the P_{10} Area x P_{10} Pay is less than 10 percent – the chance of getting the calculated result is only 3.5 percent ($p_{3.5}$). As you multiply additional P_{10} values, the probability of achieving the calculated value becomes less likely. Similarly, multiplying P_{90} parameters together will yield a result that has a probability greater than P_{90}. As such, when multiplying independent distributions together the results must be adjusted via interpolation to determine final P_{90} and P_{10} values.

The results appearing in this report represent interpolated P_{90} and P_{10} values. As defined by COGEH (and the Petroleum Resource Management System "PRMS"), the P_{50} estimate is the "best estimate" for reporting purposes.

Production forecasts

Production forecasts were based on historical trends or by comparison with other wells in the immediate area producing from similar reservoirs. Non-producing gas reserves were forecast to come on-stream within the first two years from the effective date under direct sales pricing and deliverability assumptions, if a tie-in point to an existing gathering system was in close proximity (approximately two miles). If the tie-in point was of a greater distance (and dependent on the reserve volume and risk) the reserves were forecast to come on-stream in years three or four from the effective date. These on-stream dates were used when the company could not provide specific on-stream date information.

For reserve volumes that meet all reserve category rules but are behind casing and waiting on depletion of the producing zone, these volumes are forecast to be brought on-stream following the end of the existing production.

Land schedule and maps

The evaluated company provided schedules of land ownership which included lessor and lessee royalty burdens. The land data was accepted as factual and no investigation of title by Deloitte was made to verify the records.

Well maps included within this report represent all of the company's interests that were evaluated in the specified area.

Geology

An initial review of each property is undertaken to establish the produced maturity of the reservoir being evaluated. Where extensive production history exists a geologic analysis is not conducted since the remaining hydrocarbons can be determined by productivity analysis.

For properties that are not of a mature production nature a geologic review is conducted. This work consists of:

- Developing a regional understanding of the play,
- Assessing reservoir parameters from the nearest analogous production,
- Analysis of all relevant well data including logs, cores, and tests to measure net formation thickness (pay), porosity, and initial water saturation, and
- Auditing of client mapping or developing maps to meet Deloitte's need to establish volumetric hydrocarbons-in-place.

Procedures specific to the project are discussed in the body of the report.

Royalties and taxes

General

All royalties and taxes, including the lessor and overriding royalties, are based on government regulations, negotiated leases or farm-out agreements, that were in effect as of the evaluation effective date. If regulations change, the net after royalty recoverable reserve volumes may differ materially.

Deloitte utilizes a variety of reserves and valuation products in determining the result sets.

Capital and operating considerations

Operating and capital costs were based on current costs escalated to the date the cost was incurred, and are in current year dollars. The economic runs provide the escalated dollar costs as found in the Pricing Table 1 in the Price and Market Demand section.

Reserves estimated to meet the standards of NI 51-101 for constant prices and costs (optional), are based on unescalated operating and capital costs.

Capital costs were either provided by the Company (and reviewed by Deloitte for reasonableness); or determined by Deloitte taking into account well capability, facility requirement, and distance to markets. Facility expenditures for shut-in gas are forecast to occur prior to the well's first production.

Operating costs were determined from historical data on the property as provided by the evaluated Company. If this data was not available or incomplete, the costs were based on Deloitte experience and historical database. Operating costs are defined into three types.

The first type, variable ($/Unit), covers the costs directly associated with the product production. Costs for processing, gathering and compression are based on raw gas volumes. Over the life of the project the costs are inflated in escalated runs to reflect the increase in costs over time. In a constant dollar review the costs remain flat over the project life.

The second type, fixed plant or battery ($/year), is again a fixed component over the project life and reflects any gas plant or battery operating costs allocated back to the evaluated group. The plant or battery can also be run as a separate group and subsequently consolidated at the property level.

The third type takes the remaining costs that are not associated with the first two and assigns them to the well based on a fixed and variable component. A split of 65 percent fixed and 35 percent variable assumes efficiencies of operation over time, i.e.: the well operator can reduce the number of monthly visits as the well matures, workovers may be delayed, well maintenance can also be reduced. The basic assumption is that the field operator will continue to find efficiencies to reduce the costs over time to maintain the overall $/Boe cost. Thus as the production drops over time the 35 percent variable cost will account for these efficiencies. If production is flat all the costs will also remain flat. Both the fixed and variable costs in this type are inflated in the escalated case and held constant in the constant dollar review. These costs also include property taxes, lease rentals, government fees, and administrative overhead.

In reserve evaluations conducted for purposes of NI 51-101, or, if an economic analysis was prepared for a resource evaluation, well abandonment and reclamation costs have been included and these costs were either provided by the company (and reviewed by Deloitte for reasonableness) or based on area averages (only the base abandonment costs were utilized and no consideration for groundwater protection, vent flow repair costs, or gas migration costs were considered). If there were multiple events to abandon the costs were increased by a 25 percent factor. Site reclamation costs were based on information provided by the company or based on area averages. For undeveloped reserve estimates for undrilled locations, both abandonment and site reclamation costs are also included for the purpose of determining whether reserves should be attributed to that property in the first year in which the reserves are considered for attribution to the property.

Price and market demand forecasts

Base case forecast effective December 31, 2017

The attached price and market forecasts have been prepared by Deloitte, based on information available from numerous government agencies, industry publications, oil refineries, natural gas marketers, and industry trends.

The prices are Deloitte’s best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

In preparing the price forecast Deloitte considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The base forecast for both oil and gas is based on NYMEX futures in US dollars.

The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are Deloitte’s interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Deloitte Resource Evaluation & Advisory
Canadian Domestic Forecast
Base Case Forecast Effective December 31 2017

					Crude Oil Pricing							Natural Gas Liquids Pricing Edmonton Par Prices				Natural Gas Pricing							Sulphur
		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	WTI at Cushing Oklahoma US$/bbl Real	WTI at Cushing Oklahoma US$/bbl Current	Edmonton City Gate C$/bbl Real	Edmonton City Gate C$/bbl Current	WCS 20.5 Deg. API Hardisty C$/bbl Current	Bow River 25 Deg. API Hardisty C$/bbl Current	Heavy Oil 12 Deg. API Hardisty C$/bbl Current	Ethane C$/bbl Current	Propane C$/bbl Current	Butane C$/bbl Current	Pentanes + Condensate C$/bbl Current	Alberta Reference Average Price C$/mcf Current	Alberta AECO Average Price C$/mcf Real	Alberta AECO Average Price C$/mcf Current	B.C. Direct Stn. 2 Sales C$/mcf Current	NYMEX Henry Hub US$/Mcf Real	NYMEX Henry Hub US$/Mcf Current	Ontario Dawn Reference Point C$/mcf Current	Alberta Plant Gate C$/lt Current
H	2007	2.4%	2.4%	0.997	$96.23	$91.69	$94.44	$89.98	$50.19	$50.95	$31.47	$18.35	$60.24	$77.79	$98.37	$6.17	$6.79	$6.47	$6.75	$7.46	$7.11	$7.47	$143.08
i	2008	2.4%	2.4%	0.943	$102.31	$99.57	$105.62	$102.80	$82.95	$83.90	$73.08	$22.59	$56.96	$83.54	$109.77	$7.88	$8.38	$8.16	$8.20	$9.11	$8.86	$9.88	$303.83
s	2009	0.3%	0.3%	0.880	$62.95	$61.65	$67.49	$66.10	$58.66	$59.80	$54.40	$11.61	$34.62	$56.21	$69.49	$3.85	$4.04	$3.96	$4.17	$4.03	$3.95	$4.80	($5.08)
t	2010	1.8%	1.8%	0.971	$83.24	$79.40	$81.58	$77.80	$67.22	$68.18	$60.62	$11.53	$45.19	$68.79	$84.02	$3.76	$4.20	$4.01	$4.01	$4.60	$4.39	$4.79	$56.94
o	2011	2.9%	2.9%	1.012	$99.24	$94.88	$99.92	$95.54	$77.12	$78.42	$69.60	$10.30	$52.41	$86.98	$105.24	$3.46	$3.80	$3.63	$3.34	$4.18	$4.00	$4.34	$101.60
r	2012	1.5%	1.5%	1.001	$96.47	$94.11	$88.74	$86.57	$73.10	$74.41	$64.07	$6.73	$30.80	$75.47	$99.67	$2.25	$2.45	$2.39	$2.29	$2.82	$2.75	$3.11	$126.81
i	2013	0.9%	0.9%	0.972	$100.76	$97.91	$96.08	$93.36	$74.97	$76.29	$65.49	$8.68	$38.54	$77.44	$103.52	$2.98	$3.27	$3.17	$3.11	$3.84	$3.73	$4.13	$62.17
c	2014	1.9%	1.9%	0.906	$96.15	$93.26	$96.91	$94.00	$81.06	$81.49	$73.70	$12.46	$42.93	$59.43	$101.47	$4.22	$4.64	$4.50	$4.16	$4.53	$4.39	$5.76	$88.99
a	2015	1.1%	1.1%	0.783	$49.96	$48.69	$58.49	$57.00	$44.80	$45.23	$39.63	$7.49	$5.35	$33.70	$55.15	$2.56	$2.76	$2.69	$1.81	$2.70	$2.63	$3.72	$107.45
l	2016	1.4%	1.4%	0.755	$43.79	$43.15	$52.98	$52.22	$38.90	$39.23	$34.08	$6.04	$8.71	$31.45	$52.43	$1.93	$2.19	$2.16	$1.75	$2.55	$2.52	$3.46	$45.40
2	12 Mths H	1.6%	1.6%	0.771	$50.84	$50.84	$62.11	$62.11	$50.85	$51.17	$45.03	$6.06	$27.56	$40.96	$62.85	$2.19	$2.16	$2.16	$1.55	$2.99	$2.99	$3.96	$35.21
0	0 Mths F	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1																							
7	Avg.	N/A	N/A	0.771	$50.84	$50.84	$62.11	$62.11	$50.85	$51.17	$45.03	$6.06	$27.56	$40.96	$62.85	$2.19	$2.16	$2.16	$1.55	$2.99	$2.99	$3.96	$35.21
F	2018	0.0%	0.0%	0.780	$55.00	$55.00	$65.40	$65.40	$46.40	$55.40	$41.40	$5.60	$39.25	$42.50	$68.65	$2.25	$2.00	$2.00	$1.25	$2.80	$2.80	$3.85	$35.00
o	2019	2.0%	2.0%	0.800	$57.50	$58.65	$66.90	$68.25	$50.90	$55.00	$45.80	$6.45	$37.55	$44.35	$71.65	$2.55	$2.25	$2.30	$1.75	$2.90	$2.95	$4.00	$35.70
r	2020	2.0%	2.0%	0.825	$60.00	$62.40	$67.90	$70.65	$55.05	$57.10	$49.85	$7.70	$35.30	$45.95	$74.20	$3.00	$2.65	$2.75	$2.35	$3.10	$3.25	$4.15	$36.40
e	2021	2.0%	2.0%	0.850	$65.00	$69.00	$71.75	$76.15	$60.20	$62.35	$57.05	$8.35	$34.30	$49.50	$79.95	$3.25	$2.80	$2.95	$2.55	$3.30	$3.50	$4.40	$37.15
c	2022	2.0%	2.0%	0.850	$70.00	$75.75	$77.65	$84.05	$67.80	$70.00	$64.55	$8.95	$33.60	$54.60	$88.25	$3.45	$2.95	$3.20	$2.75	$3.40	$3.70	$4.60	$37.90
a	2023	2.0%	2.0%	0.850	$70.00	$77.30	$77.65	$85.75	$69.15	$71.40	$65.85	$9.60	$34.30	$55.70	$90.05	$3.70	$3.10	$3.40	$3.00	$3.55	$3.90	$4.90	$38.65
s	2024	2.0%	2.0%	0.850	$70.00	$78.85	$77.65	$87.45	$70.55	$72.80	$67.20	$10.60	$34.95	$56.80	$91.85	$4.05	$3.35	$3.75	$3.30	$3.75	$4.20	$5.25	$39.40
t	2025	2.0%	2.0%	0.850	$70.00	$80.40	$77.65	$89.20	$71.95	$74.25	$68.50	$11.45	$35.65	$57.95	$93.70	$4.35	$3.55	$4.10	$3.60	$3.90	$4.50	$5.55	$40.20
	2026	2.0%	2.0%	0.850	$70.00	$82.00	$77.65	$91.00	$73.40	$75.75	$69.90	$11.85	$36.40	$59.10	$95.55	$4.50	$3.60	$4.20	$3.75	$3.95	$4.65	$5.75	$41.00
	2027	2.0%	2.0%	0.850	$70.00	$83.65	$77.65	$92.80	$74.85	$77.25	$71.30	$12.20	$37.10	$60.30	$97.45	$4.65	$3.65	$4.35	$3.90	$4.00	$4.80	$5.90	$41.85
	2028	2.0%	2.0%	0.850	$70.00	$85.35	$77.65	$94.65	$76.35	$78.80	$72.70	$12.45	$37.85	$61.50	$99.40	$4.75	$3.65	$4.45	$3.95	$4.00	$4.90	$6.05	$42.65
	2029	2.0%	2.0%	0.850	$70.00	$87.05	$77.65	$96.55	$77.90	$80.40	$74.15	$12.70	$38.60	$62.75	$101.40	$4.85	$3.65	$4.55	$4.05	$4.00	$4.95	$6.15	$43.50
	2030	2.0%	2.0%	0.850	$70.00	$88.80	$77.65	$98.50	$79.45	$82.00	$75.65	$12.95	$39.40	$64.00	$103.45	$4.95	$3.65	$4.65	$4.10	$4.00	$5.05	$6.30	$44.40
	2031	2.0%	2.0%	0.850	$70.00	$90.55	$77.65	$100.45	$81.05	$83.65	$77.15	$13.20	$40.15	$65.25	$105.50	$5.05	$3.65	$4.70	$4.20	$4.00	$5.15	$6.40	$45.30
	2032	2.0%	2.0%	0.850	$70.00	$92.35	$77.65	$102.45	$82.65	$85.30	$78.70	$13.45	$40.95	$66.55	$107.60	$5.15	$3.65	$4.80	$4.30	$4.00	$5.30	$6.55	$46.20
	2033	2.0%	2.0%	0.850	$70.00	$94.20	$77.65	$104.50	$84.30	$87.00	$80.30	$13.75	$41.80	$67.90	$109.75	$5.25	$3.65	$4.90	$4.35	$4.00	$5.40	$6.65	$47.10
	2034	2.0%	2.0%	0.850	$70.00	$96.10	$77.65	$106.60	$86.00	$88.75	$81.90	$14.00	$42.60	$69.25	$111.95	$5.35	$3.65	$5.00	$4.45	$4.00	$5.50	$6.80	$48.05
	2035	2.0%	2.0%	0.850	$70.00	$98.00	$77.65	$108.75	$87.75	$90.55	$83.50	$14.30	$43.50	$70.65	$114.20	$5.45	$3.65	$5.10	$4.55	$4.00	$5.60	$6.95	$49.00
	2036	2.0%	2.0%	0.850	$70.00	$100.00	$77.65	$110.90	$89.50	$92.35	$85.20	$14.55	$44.35	$72.05	$116.45	$5.55	$3.65	$5.20	$4.65	$4.00	$5.70	$7.05	$50.00
	2037	2.0%	2.0%	0.850	$70.00	$102.00	$77.65	$113.10	$91.25	$94.20	$86.90	$14.85	$45.25	$73.50	$118.80	$5.70	$3.65	$5.30	$4.75	$4.00	$5.85	$7.20	$51.00
	2037+	2.0%	2.0%	0.850	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	0.0%	2.0%	2.0%	2.0%

Notes:
- All prices are in Canadian dollars except WTI and NYMEX gas which are in U.S. dollars
- Edmonton city gate prices based on historical light oil par prices posted by the government of Alberta and Net Energy differential futures (40 Deg. API < 0.5% Sulphur)
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point
- 1 Mcf is equivalent to 1 mmbtu
- Real prices listed in 2017 dollars with no escalation considered
- Alberta gas prices, except AECO, include an average cost of service to the plant gate
- NGL prices have been switched from a mix reference to a spec reference

Glossary of terms

Deloitte subscribes to the Glossary of Terms as defined by the Canadian Oil and Gas Evaluation Handbook, Volume 2.

In this report, any reference to M$ means thousands and MM$ means millions.

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Dundee Energy Limited Partnership

Reserve estimation and economic evaluation

Detailed properties

Effective date: December 31, 2017

Deloitte.

Dundee Energy Limited Partnership

Reserve estimation and economic evaluation

Effective date: December 31, 2017

(Click on property name to open detail report)

1. Executive summary

Alberta

2. Mikwan, Alberta

Ontario

3. Corey East, Ontario
4. Goldsmith, Ontario
5. Hillman, Ontario
6. Off Shore Central, Ontario
7. Off Shore East, Ontario
8. Off Shore West, Ontario
9. Off Shore West Central, Ontario
10. Petrolia East, Ontario
11. Renwick, Ontario
12. Rochester, Ontario
13. Single Well Oil Battery, Ontario
14. Minors, Ontario