



PIERIDAE ENERGY LIMITED

**ANNUAL INFORMATION FORM
FOR THE FISCAL YEAR ENDED
DECEMBER 31, 2018**

April 24, 2019

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ABBREVIATIONS AND CONVERSION TABLE

The following are abbreviations of terms used in this Annual Information Form and a conversion table from Imperial to Metric units. Additional terms relating to reserves and other oil and gas information have the meanings set forth in Appendix E – *Definitions Used for Reserve and Resource Categories*.

ABCA	<i>Business Corporations Act</i> , R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.
AIMCo	Alberta Investment Management Corporation
AIF	this annual information form of the Corporation dated April 24, 2019.
APA	<i>Partnership Act</i> , R.S.A. 2000, c. P-3, as amended, including the regulations promulgated thereunder
BCCA	<i>Company Act</i> , R.S.B.C. 1979, c. 59, as amended, including the regulations promulgated thereunder
Bcf	billion cubic feet
boe	barrels of oil equivalent
CBCA	<i>Canada Business Corporations Act</i> , R.S.C. 1985, c. C-44, as amended, including the regulations promulgated thereunder
COGE Handbook	Canadian Oil and Gas Evaluation Handbook
DFIT	diagnostic fracture injection testing
DST	drill stem test
GOR	gas-oil ratio
ITA	<i>Income Tax Act</i> , R.S.C. 1985, c 1 (5th Supp), as amended, including the regulations promulgated thereunder
LNG	liquid natural gas
McfGE	thousands of cubic feet of gas equivalent
MPR	maximum permissive rate
NGL	natural gas liquids
NBCCA	<i>Business Corporations Act</i> , S.N.B. 1981, c. B-9.1, as amended, including the regulations promulgated thereunder
NI 51-101	National Instrument 51-101
ORRI	overriding royalty interest
P&NG	petroleum and natural gas
PG	petroleum and gas
PIIP	Petroleum Initially-In-Place
QBCA	<i>Business Corporations Act</i> , C.Q.L.R. c. S-31.1, as amended, including the regulations promulgated thereunder
QCA	<i>Companies Act</i> , C.Q.L.R. c. C-38, as amended, including the regulations promulgated thereunder
SPE-PRMS	Society of Petroleum Engineers - Petroleum Resources Management System
TSXV	TSX Venture Exchange
TVD	total vertical depth
WI	working interest

Conversion Factors		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m ³) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m ³ (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m ³ (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m ³ (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m ³ (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m ³ (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10 ³ m ³) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10 ³ m ²)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10 ⁴ m ³) (ha.m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= 10 ³ m ³ /m ³ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F)	x 0.03743222	= megajoules per cubic metre (MJ/m ³) (@ 101.325 kPaa, 15°C)
\$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule (\$/GJ)
\$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= \$/10 ³ m ³ (@ 101.325 kPaa, 15°C)
\$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= \$/10 ³ m ³ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
\$/bbl	x 6.29287	= \$/m ³ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m ³ /m ³)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m ³)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m ³)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C ₃)	x 5.6339198	= cubic metres per million cubic metres (m ³ /10 ⁶ m ³)
bbl/MMcf (C ₄)	x 5.6367593	= (m ³ /10 ⁶ m ³)
bbl/MMcf (C ₅₊)	x 5.6403087	= (m ³ /10 ⁶ m ³)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres (t/10 ⁶ m ³)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C ₅₊)	x 161.3577	= millilitres per cubic metre (mL/m ³)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C ₅₊)	x 134.3584	= (mL/m ³)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa.s)

FORWARD LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management plans and assessments of future plans and operations, Pieridae Energy Limited's ("Pieridae" or the "Corporation") expected 2019 capital budget, Pieridae's future business plan and strategy, Pieridae's criteria for evaluating acquisitions and other opportunities, Pieridae's intentions with respect to future acquisitions and other opportunities, plans and timing for development of undeveloped and probable resources, timing of when the Corporation may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, wells to be drilled, the weighting of commodity expenses, expected production and performance of oil and natural gas properties, results and timing of projects, access to adequate pipeline capacity and third-party infrastructure, growth expectations, supply and demand for oil, natural gas liquids, and natural gas, industry conditions, government regulations and regimes, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute "forward-looking statements" or "forward-looking information" within the meaning of Applicable Securities Laws (as defined herein) (collectively "forward-looking statements"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue", "shall", "estimate", "expect", "propose", "might", "project", "predict", "forecast" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management.

Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of resources estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and resources estimates of Pieridae's reserves provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements, but which may prove to be incorrect. Although Pieridae believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Pieridae can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Pieridae operates; the timely receipt of any required regulatory approvals; the ability of Pieridae to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects which Pieridae has an interest in, to operate the field in a safe, efficient and effective manner; the ability of Pieridae to obtain financing on acceptable terms; the ability to replace and expand oil and natural gas resources through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Pieridae to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Pieridae operates; timing and amount of capital expenditures, future sources of funding, production levels, weather conditions, success of exploration and development activities, access to gathering, processing and pipeline systems, advancing technologies, and the ability of Pieridae to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Pieridae's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), and at Pieridae's website (www.pieridaeenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and Pieridae assumes no obligation to update or review them to reflect new events or circumstances except as required by Applicable Securities Laws.

Forward-looking statements contained herein concerning the oil and gas industry and Pieridae's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Pieridae believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Pieridae is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

PRESENTATION OF INFORMATION

The information contained in this Annual Information Form (AIF) is presented as at December 31, 2018 except where otherwise noted.

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

RESERVES AND OTHER OIL AND GAS INFORMATION

The reserves information provided in this AIF is derived from the report of Deloitte LLP (Deloitte) on Pieridae's oil and gas reserves in Western Canada effective as of December 31, 2018 and dated and prepared as of March 11, 2019 (the Deloitte Reserves Report). All of Pieridae's reserves are held by its wholly-owned subsidiary, Ikkuma Resources Corp. The Deloitte Reserves Report was prepared in accordance with the standards included in the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101).

Sproule Associates Limited (Sproule) has also prepared an evaluation of the contingent resources of Pieridae in the Haldimand area of Québec effective December 31, 2018 and dated and prepared as of January 3, 2019 (the Haldimand Resource Report). Sproule has also prepared an evaluation of the contingent resources of Pieridae in the Bourque area of Québec effective December 31, 2018 and dated and prepared as of January 3, 2019 (the Bourque Resource Report, and together with the Haldimand Resource Report, the Resource Reports). Summaries of Pieridae's resources as evaluated in the Resource Reports are appended to this AIF as Appendix A.

With respect to the disclosure of reserves contained herein relating to portions of Pieridae's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Estimates of future net, revenue, whether calculated without discount or using a discount rate, do not represent fair market value.

With respect to the discovered resources (including contingent resources) disclosed in this AIF, there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources) disclosed in this AIF, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Unless otherwise indicated, all volumes of Pieridae's reserves and resources presented herein are on a "gross" basis and all volumes of Pieridae's resources presented herein are on an unrisks basis, meaning that they have not been adjusted for the chance of commerciality.

CAUTION RESPECTING BOE

In this AIF, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CORPORATE STRUCTURE OF PIERIDAE

NAME, ADDRESS AND INCORPORATION

Pétrolia inc. ("Pétrolia"), a predecessor corporation of Pieridae, was incorporated on January 22, 2002 under the name 9112-6094 Québec Inc. pursuant to Part 1A of the QCA. Subsequently, Pétrolia changed its name to Pétrolia Inc. by Articles of Amendment dated September 10, 2002. On October 20, 2004, the 4,326,154 Class A shares issued and outstanding of Pétrolia were subdivided into 5,191,389 Class A shares. On October 21, 2004, Pétrolia filed Articles of Amendment in order to amend its share capital, convert its issued and outstanding shares into common shares and to remove the private company provisions from its Articles.

Pieridae Energy Limited ("Former Pieridae"), the other predecessor corporation of Pieridae, was incorporated on May 29, 2012 pursuant to the CBCA and was extra-provincially registered on May 31, 2012 under the ABCA. On October 4, 2012 Pieridae filed Articles of Amendment in order to consolidate the number of its then issued and outstanding common shares into a smaller number of shares on a 5.1282 to 1 basis.

On October 24, 2017, pursuant to a plan of arrangement under the CBCA (the "Pétrolia Arrangement"), Former Pieridae and Pétrolia amalgamated and continued as one corporation under the CBCA with the name Pieridae Energy Limited ("Pieridae").

On December 20, 2018, pursuant to a plan of arrangement under the Business Corporations Act (Alberta), Pieridae acquired all of the issued and outstanding shares of Ikkuma Resources Corp. Consideration consisted of the issuance of 21.6 million Pieridae common shares valued at approximately \$56.1 million.

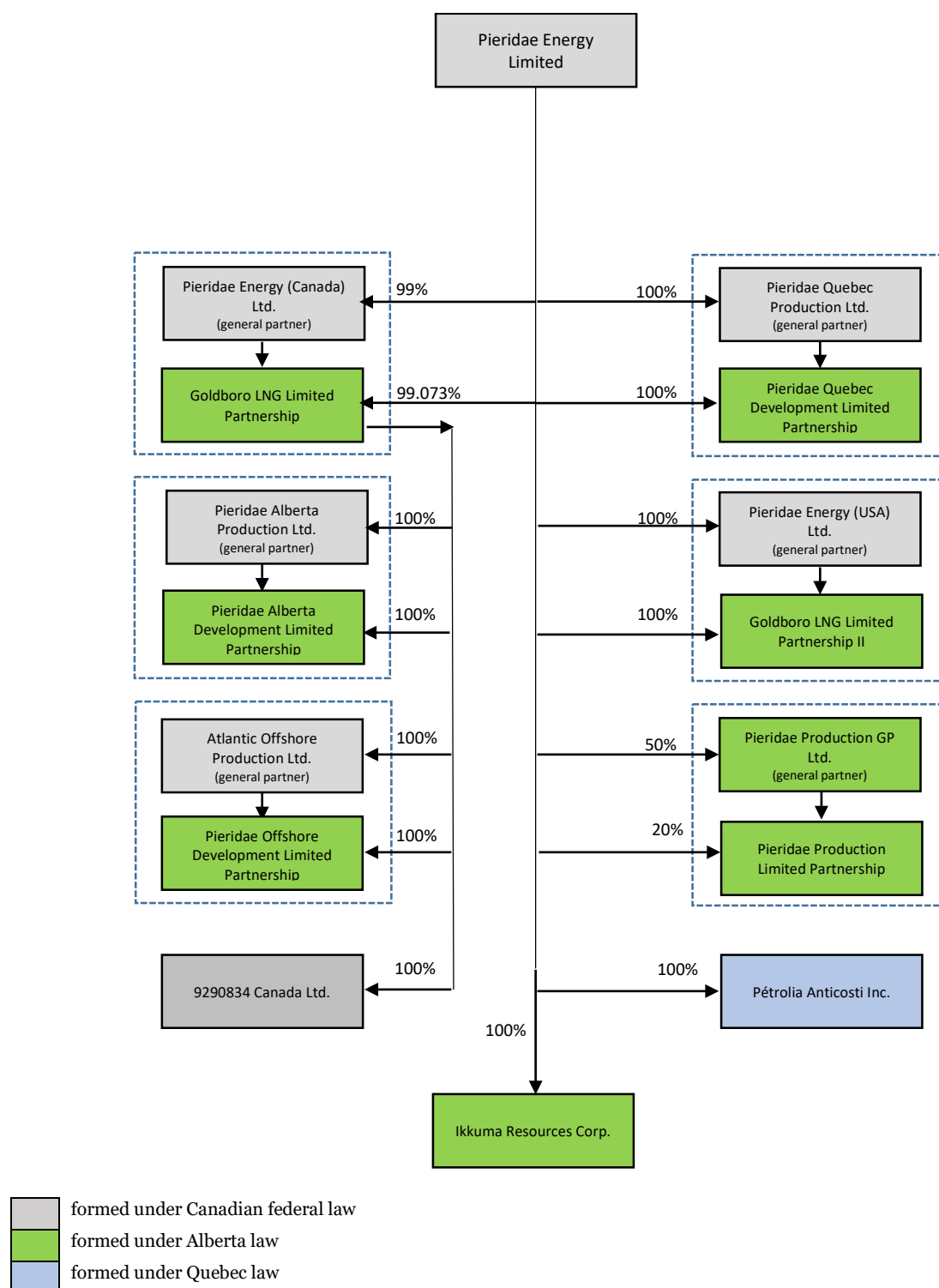
Pieridae is a reporting issuer, or the equivalent, in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland. The shares of the Corporation trade on the TSX Venture Exchange under the symbol "PEA". The registered and head office of Pieridae is located at 3100, 308 4th Avenue SW, Calgary, Alberta T2P 0H7. Its operations offices are located at 1718 Argyle Street, Suite 730, Halifax, Nova Scotia B3J 3N6 and 511, Saint-Joseph Street East, 2nd Floor, local 304, Québec City, Québec G1K 3B7.

INTERCORPORATE RELATIONSHIPS

The following table describes the intercorporate relationships among Pieridae and its material direct and indirect subsidiaries.

Subsidiary	Jurisdiction of Incorporation or Formation	Percentage of Voting Securities (direct or indirect)
Ikkuma Resources Corp.	Alberta	100%
Pieridae Energy (Canada) Ltd.	Federal	99.073%
Goldboro LNG Limited Partnership	Alberta	99%
9290834 Canada Ltd.	Federal	100%
Pieridae Energy (USA) Ltd.	Federal	100%
Goldboro LNG Limited Partnership II	Alberta	100%
Pieridae Production GP Ltd.	Alberta	50%
Pieridae Production Limited Partnership	Alberta	20%
Atlantic Offshore Production Ltd.	Federal	100%
Pieridae Offshore Development Limited Partnership	Alberta	100%
Pieridae Alberta Production Ltd.	Federal	100%
Pieridae Alberta Development Limited Partnership	Alberta	100%
Pieridae Québec Production Ltd.	Federal	100%
Pieridae Québec Development Limited Partnership	Alberta	100%
Pétrolia Anticosti Inc.	Québec	100%

The following diagram shows the intercorporate relationships among us and our subsidiaries as of the date hereof:



Notes:

Pieridae Energy Limited holds all of its interest in each limited partnership as a limited partner in such partnership.

Pieridae Energy (Canada) Ltd.

Pieridae Energy (Canada) Ltd. (“Pieridae Canada”) is the sole general partner of Goldboro LNG Limited Partnership. Pieridae Canada was incorporated on February 14, 2012 under the CBCA and was extra-provincially registered under the ABCA on October 3, 2012 and under the Corporations Registration Act (Nova Scotia) on October 5, 2012.

Goldboro LNG Limited Partnership

Goldboro LNG Limited Partnership (“Goldboro Canada LP”) was formed on December 11, 2012 under the APA for the purposes of developing, constructing and operating the proposed Goldboro LNG Facility (excluding Train Two) and of procuring long-term conventional natural gas supply from its affiliates in Canada and transporting the natural gas to the proposed Goldboro LNG Facility for use as feed gas and fuel in the production of LNG from Train One.

9290834 Canada Ltd.

9290834 Canada Ltd. (“9290834”) was incorporated on May 11, 2015 under the CBCA and was extra-provincially registered on June 4, 2015 under the Corporations Registration Act (Nova Scotia). 9290834, in its capacity as agent and bare trustee of Pieridae Canada and Goldboro Canada LP, holds legal title to the lands on which the proposed Goldboro LNG Facility is being developed and is proposed to be constructed and operated.

Pieridae Energy (USA) Ltd.

Pieridae Energy (USA) Ltd. (“Pieridae USA”) is the sole general partner of Goldboro LNG Limited Partnership II. Pieridae USA was incorporated on August 16, 2013 under the CBCA and was extra-provincially registered under the ABCA on August 22, 2013 and under the Corporations Registration Act (Nova Scotia) on November 6, 2013.

Goldboro LNG Limited Partnership II

Goldboro LNG Limited Partnership II (“Goldboro USA LP”) was formed on September 24, 2013 under the APA for the purposes of developing, constructing and operating Train Two of the proposed Goldboro LNG Facility and of procuring long-term natural gas supply from its affiliate producers in Canada and producers in the United States and transporting the natural gas to the proposed Goldboro LNG Facility for use as feed gas and fuel in the production of LNG from Train two. No such supply agreement has been entered into by Goldboro USA LP with any such producers.

Pieridae Production GP Ltd.

Pieridae Production GP Ltd. (“Production GP”) is the sole general partner of Pieridae Production Limited Partnership. Production GP was incorporated on February 5, 2013 under the ABCA and was extra-provincially registered on March 1, 2013 under the NBBCA.

Pieridae Production Limited Partnership

Pieridae Production Limited Partnership (“Production LP”) was formed on February 27, 2013 under the APA for the purposes of acquiring and developing natural gas resource properties in New Brunswick.

Atlantic Offshore Production Ltd.

Atlantic Offshore Production Ltd. (“Atlantic Production”) is the sole general partner of Pieridae Offshore Development Limited Partnership. Atlantic Production was incorporated on September 23, 2015 under the CBCA and was extra-provincially registered on September 25, 2015 under the ABCA and on September 28, 2015 under the Companies Act (Nova Scotia). Atlantic Production is presently inactive.

Pieridae Offshore Development Limited Partnership

Pieridae Offshore Development Limited Partnership (“Offshore Development LP”) was formed on October 20, 2015 under the APA for the purposes of acquiring and developing natural gas resource properties in Nova Scotia and offshore Nova Scotia. Offshore Development LP is presently inactive.

Pieridae Alberta Production Ltd.

Pieridae Alberta Production Ltd. (“Alberta Production”) is the sole general partner of Pieridae Alberta Development Limited Partnership. Alberta Production was incorporated on June 6, 2018 under the CBCA and was extra-provincially registered on June 7, 2018 under the ABCA. Alberta Production is presently inactive.

Pieridae Alberta Development Limited Partnership

Pieridae Alberta Development Limited Partnership (“Alberta Development LP”) was formed on June 29, 2018 under the APA for the purposes of acquiring and developing natural gas resource properties in Western Canada. Alberta Development LP is presently inactive.

Pieridae Québec Production Ltd.

Pieridae Québec Production Ltd. (“Québec Production”) is the sole general partner of Pieridae Québec Development Limited Partnership. Québec Production was incorporated on December 27, 2017 under the CBCA and was extra-provincially registered on January 9, 2018 under the QBCA.

Pieridae Québec Development Limited Partnership

Pieridae Québec Development Limited Partnership (“Québec Development LP”) was formed on April 13, 2018 under the APA for the purposes of acquiring and developing natural gas resource properties in Québec. Québec Development LP holds the resource properties formerly held by Pétrolia Inc.

Pétrolia Anticosti Inc.

Pétrolia Anticosti inc. (“Pétrolia Anticosti”) was incorporated on March 17, 2014 under the to the QBCA and currently provides services in relation to the demobilization of infrastructure and the capping of wells necessitated by the Anticosti Settlement.

Ikkuma Resources Corp.

Ikkuma Resources Corp. (“Ikkuma”) is a wholly-owned subsidiary of Pieridae. It was acquired by Pieridae on December 20, 2018, through a plan of arrangement under the ABCA. Ikkuma was initially incorporated pursuant to the provisions of the BCCA but subsequently continued out of British Columbia and into Alberta and continues to be governed by the provisions of the ABCA.

GENERAL DEVELOPMENT OF THE BUSINESS

HISTORY OF FORMER PIERIDAE PRIOR TO AMALGAMATION

The following is a summary description of the major events which influenced the general development of Former Pieridae and which are material to the current business of the Corporation, for the financial years ending on December 31, 2016, and for part of the financial year completed on December 31, 2017 until its amalgamation with Pétrolia on October 24, 2017.

2016

On February 5, 2016, the US Department of Energy issued the Order No. 3768 authorizing the annual export, using the capacity of the U.S. portion of the Maritimes & Northeast Pipeline that is in service as of February 5, 2016, of up to 292 Bcf natural gas sourced from the United States to Canada for liquefaction in Canada and re-export as LNG to countries with which the United States does not have a free-trade agreement. This authorization is for a period of twenty years commencing on the earlier of the date of first commercial re-export and February 5, 2023. The volume of natural gas that is authorized for export under Order No. 3768 is not additive to the volume of natural gas that is authorized for export under Order No. 3639.

On May 20, 2016, the Export Licence GL-313 and Import Licence GI-314 issued by the NEB on August 13, 2015 were officially approved by Order in Council No. P.C. 2016-391.

2017

On May 3, 2017, Former Pieridae completed the successful negotiation of a collective agreement affecting 15 of the relevant trade unions in Nova Scotia which will be relied upon to construct the Goldboro LNG Facility.

On July 28, 2017, the Labour Board (Nova Scotia) issued the orders LB-1322 and LB-1323 declaring that the collective agreement is a project agreement with effect commencing July 27, 2017 in accordance with subsection 5(3) of the Construction Project Labour Relations Act (Nova Scotia).

On October 24, 2017 the deadline for the commencement of work on the Project Site imposed by paragraph 1.3 of the environmental assessment approval issued by the Minister of the Environment of Nova Scotia of the proposed Goldboro LNG Facility was extended from March 21, 2018 to March 21, 2019. On November 9, 2018 the Government of Nova Scotia confirmed that this condition was satisfied by the clearing of the Project Site in early 2018.

HISTORY OF PÉTROLIA PRIOR TO AMALGAMATION

The following is a summary description of the major events which influenced the general development of Pétrolia and which are material to the current business of the Corporation, for the financial years completed on December 31, 2016, and for part of the financial year completed on December 31, 2017 until its amalgamation with Pieridae on October 24, 2017.

2016

On May 18, 2016, Pétrolia announced the commencement of long-term production testing on Haldimand 4. Pétrolia was issued all the necessary government approvals to begin such production test. The Corporation and its then partner Québénergie Inc. (“Québénergie”) approved the long-term test program.

On July 15, 2016, Pétrolia confirmed that it had closed the second phase of the financing for the Bourque project by Ressources Québec for a total amount of \$8,500,000. This investment constituted a direct participation in the four permits related to the Bourque property in the amount of \$2,000,000 in cash and a contribution of \$6,500,00, by way of calls for funds, to carry out the exploration program. This investment allowed Ressources Québec to obtain an additional 38.88% interest in Pétrolia's participation and a 1.32% of TUGLIQ Énergie Corp.'s ("TUGLIQ Energy") participation in such permits. The proceeds of this financing are used by Pétrolia to carry out the exploration program on the Bourque property. Following the completion of this second phase of financing of the Bourque property, Pétrolia's participation in the joint venture amounted to 51.03 %, Ressources Québec to 45 % and TUGLIQ Energy to 3.97 %.

On July 15, 2016, Pétrolia issued 4,629,626 flow-through shares at the price of \$0.27 per share (pre-consolidation) amounting to \$1,250,015 in gross proceeds. The proceeds from these private placements were used by Pétrolia to incur exploration costs in Canada on Pétrolia's properties located in the province of Québec.

On September 2, 2016, Pétrolia confirmed the existence of a functional oil reservoir comprised of natural fractures on the Haldimand property as well as the suspension of the production test for the Haldimand No. 4 well, started in May 2016.

On September 26, 2016, Pétrolia announced the commencement of the operations leading to the drilling of the lateral section of Bourque No. 1. The drilling of the horizontal leg of the reservoir was followed by logging and completion. The lower open hole section of the well was permanently abandoned through the installation of 4 cement plugs. Thereafter, the drilling rig was moved a few metres ("m") away towards the enlarged portion of the Bourque No. 1 site in order to drill a third well (Bourque HZ No. 3).

On October 27, 2016, Pétrolia issued 6,077,579 flow-through shares at the price of \$0.19 per share (pre-consolidation) amounting to \$1,154,740 in gross proceeds. The proceeds from these private placements were used by Pétrolia to incur exploration costs in Canada on Pétrolia's properties located in the province of Québec.

On December 23, 2016, Pétrolia announced that the most recent step in the process of verifying the presence of resources on the Bourque property, namely the re-entry and completion of Bourque No. 1 as well as an additional drilling (Bourque HZ No. 3), was completed on time and within the budget. This drilling revealed the presence of gas and oil in the Forillon formation. The Bourque HZ No. 3 completion program was delayed in order to analyze the data collected on Bourque No. 1 and to finalize the plan for production tests. As a result, Pétrolia demobilized the equipment until spring 2017. In the meantime, measuring instruments were installed in the wells in order to continue collecting data and the site was secured for the rest of the season.

2017

During the first quarter of the fiscal year 2017, the Québec government confirmed its support for Anticosti's designation as a UNESCO World Heritage Site. Following this announcement, the Québec government-initiated negotiations with Pétrolia and its partners in Anticosti Hydrocarbons L.P. with the aim of ending oil and natural gas exploration on Anticosti Island. On July 24, 2017, the Government of Québec adopted an order in council, published in the Gazette officielle du Québec and effective July 28, 2017, prohibiting the exploration and development of oil and gas on Anticosti Island. It also announced the conclusion of agreements with certain companies involved in oil and gas exploration on Anticosti Island, particularly Junex inc. as well as Corridor Resources Inc. and Saint-Aubin E&P (Québec) Inc., two of the partners of Anticosti Hydrocarbons L.P.

On March 17, 2017, Pétrolia issued 5,222,223 flow-through shares at the price of \$0.18 per share (pre-consolidation) for gross proceeds of \$940,000. The proceeds from these private placements were used by Pétrolia to incur exploration costs in Canada on Pétrolia's properties located in the province of Québec.

On September 29, 2017, the Government of Québec and Pétrolia entered into a settlement agreement concerning the cessation of oil & gas exploration and development activities on Anticosti Island. The cessation of work, the end of the exploration program, as well as the termination of the operator contract held by Pétrolia Anticosti Inc. were negotiated in return for a \$20.4 million financial compensation for Pétrolia, which held a 21.67% interest in the Anticosti project and \$150,000 for Pétrolia Anticosti Inc. Under this agreement, the Government of Québec obtained the rights to certain of Pétrolia's exploration and evaluation assets on Anticosti Island and will assume the financial obligations related to the future restoration of these properties, for which a net liability of \$152,677 was recorded as at September 29, 2017, consisting of exploration and evaluation assets of \$147,975 and a provision for site restoration of \$300,652. Also, under this agreement, the Government of Québec undertook to vote, through Ressources Québec, in favour of the proposed arrangement with Pieridae as well as to sign the support and pooling agreement and the same escrow agreement as the other Pétrolia insiders.

On October 23, 2017, Pétrolia acquired complete control of the Haldimand project. Previously, it had a 50% interest with Québénergie holding the other 50%.

AMALGAMATION OF FORMER PIERIDAE AND PÉTROLIA

On May 15, 2017 Former Pieridae and Pétrolia entered into a definitive agreement providing for an amalgamation by way of plan of arrangement pursuant to which Pétrolia and Former Pieridae amalgamated to form a new entity to be named Pieridae Energy Limited (the "PEL Arrangement"). The completion of the PEL Arrangement resulted in a reverse takeover of the Corporation as defined in the policies of the TSX Venture Exchange. The Amalgamation was subject to the receipt of shareholder and court approvals and regulatory approval. At meetings of their respective shareholders held on October 7, 2017 for Pétrolia and September 26, 2017 for Former Pieridae, shareholders of both Pétrolia and Former Pieridae approved the Amalgamation. On October 11, 2017, the Superior Court of Québec issued a final order approving the Amalgamation.

In connection with the Arrangement, Former Pieridae raised net proceeds of \$24,632,500 in a brokered subscription receipt financing, in which 2,052,130 subscription receipts of Former Pieridae were converted into common shares of Former Pieridae, which in turn were subsequently converted into common shares of the Corporation in accordance with the exchange mechanics described as follows.

On October 24, 2017, the PEL Arrangement became effective with the issuance, by Corporations Canada, of a Certificate of Arrangement. Pursuant to the Arrangement, the common shares in the capital of Pétrolia (the "Pétrolia Shares") were consolidated (the "Consolidation") on the basis of one (1) post-Consolidation Pétrolia Share for each twelve (12) Pétrolia Shares held by a Pétrolia shareholder (a "Pétrolia Shareholder") (subject to rounding). Former Pieridae issued to the holders ("Former Pieridae Shareholders") of common shares in the capital of Former Pieridae ("Former Pieridae Shares") 2,205,752 common shares in the capital of Pieridae ("Pieridae Shares") for each one (1) Former Pieridae Share held by a Former Pieridae Shareholder (subject to rounding), for aggregate consideration of 40,750,339 Pieridae Shares issuable to Former Pieridae Shareholders in exchange for the 18,474,574 Former Pieridae Shares which were outstanding at the effective time of the PEL Arrangement. Similarly, at the effective time of the PEL Arrangement, Pieridae issued to the Pétrolia Shareholders one (1) Pieridae Share for each one (1) Pétrolia Share held by a Pétrolia Shareholder in exchange for the 9,043,724 Pétrolia Shares (on a post-Consolidation basis) which were outstanding at the effective time of the PEL Arrangement. Each Pieridae Share issued to Former Pieridae Shareholders or to Pétrolia Shareholders pursuant to the PEL Arrangement were issued at a deemed price of \$5.667 per Pieridae Share (on a post-Consolidation basis).

After giving effect to the PEL Arrangement, there were approximately 49,794,063 Pieridae Shares issued and outstanding (calculated on a non-diluted basis).

On November 2, 2017, the Pieridae Shares commenced trading on the TSX Venture Exchange under the symbol “PEA”.

HISTORY OF IKKUMA

The following is a summary description of the major events which influenced the general development of Ikkuma and which are material to the current business of the Corporation, for the financial years completed on December 31, 2016, and 2017, and for part of the financial year completed on December 31, 2018 until its acquisition by Pieridae on December 20, 2018.

2016

On April 7, 2016, Ikkuma closed the acquisition of certain natural gas assets located in the Foothills of Alberta for cash consideration of \$2.5 million.

On May 12, 2016, Ikkuma announced the closing of a \$10 million bought deal private placement of Common Shares on a “flow-through” basis pursuant to the Income Tax Act (Canada) (“Flow-Through Shares”). Ikkuma issued 14,085,000 Flow-Through Shares at a price of \$0.71 per -Through Share.

On August 25, 2016, Ikkuma announced that its Credit Facilities were reduced to \$40 million.

2017

On May 15, 2017, Ikkuma completed a \$45 million second lien secured term loan with Alberta Investment Management Corporation (“AIMCo”), bearing interest at 7.25% per annum and maturing on March 31, 2022 (the “Second Lien Facility”). The proceeds from the Second Lien Facility were made available in a single draw and amounts borrowed under the Second Lien Facility that are repaid or prepaid are not available for re-borrowing. In addition, for no additional consideration, Ikkuma issued warrants to purchase Common Shares to AIMCo, entitling AIMCo to acquire up to 6.75 million Common Shares for a period of three years, at an exercise price of \$0.86 per Common Share (the “AIMCo Warrants”). Net proceeds from the Second Lien Facility was used to pay down all outstanding indebtedness under the Credit Facilities.

On May 25, 2017, Ikkuma entered into an amended and restated credit agreement with respect to the Credit Facilities (the “Amended and Restated Credit Agreement”) whereby the borrowing base was re-determined at \$25.0 million and the maturity date was extended to May 31, 2019.

On May 30, 2017, Ikkuma announced that it anticipated capital spending between \$20.0 and \$29.0 for 2017, and that \$10.0 million of that amount had been spent to date.

In September 2017, Ikkuma announced the closing of the non-brokered private placement of Flow-Through Shares pursuant to which 15,091,221 Flow-Through Shares were issued at a price of \$0.82 per share for gross proceeds of \$12.4 million. The gross proceeds from the \$0.82 Flow-Through Offering will be used by Ikkuma to incur Canadian exploration expenses prior to December 31, 2018.

On October 23, 2017, Ikkuma announced that it had closed the deposition of 51% of its interest in a trunk-line and associated facilities for a cash consideration in the amount of \$20 million.

On December 21, 2017, Ikkuma announced that it had closed the acquisition of certain assets located in the Alberta Foothills as well as in the British Columbia Deep Basin for a cash consideration in the amount of \$29.7 million. The acquisition more than tripled Ikkuma's production and expanded the existing crude oil development drilling inventory to more than 200 low-risk drilling locations.

2018

On May 15, 2018 Ikkuma announced that it had entered into a non-binding letter of intent to sell certain midstream assets for a purchase price of \$30 million, subject to customary adjustments, pending execution of a definitive purchase and sale agreement.

On July 5, 2018 Ikkuma announced that it had entered into a purchase and sale agreement on July 4, 2018 to sell certain midstream assets in the Alberta foothills to an undisclosed purchaser for a total cash consideration of \$23.0 million, subject to customary adjustments. The Infrastructure Asset Sale was subject to standard industry closing conditions, as well as approval from the purchaser's Board of Directors and due diligence reviews.

On August 24, 2018 Ikkuma announced that it had entered into a definitive agreement dated August 23, 2018 providing for the acquisition by Pieridae of all of the issued and outstanding shares of Ikkuma to be affected by way of a plan of arrangement under section 193 of the ABCA. The Arrangement Agreement also provided for the transfer, prior to the effective date of the Arrangement, by Ikkuma of certain interests in Cardium light oil-focused Alberta Foothills properties to a newly formed private corporation, Briko Energy Corp. ("ExploreCo"), contingent on customary regulatory approvals by the Alberta Energy Regulator ("AER").

On October 11, 2018 Ikkuma announced it closed a conveyance and sale agreement for the sale of a non-core dormant midstream facility in the Alberta foothills to an undisclosed purchaser for a total consideration of \$2.0 million, subject to customary adjustments.

On November 14, 2018 Ikkuma announced the previously announced (July 5, 2018) purchase and sale agreement to sell certain midstream assets in the Alberta foothills was terminated.

On November 15, 2018, Ikkuma announced that it has completed a financing for a \$20 million senior secured term loan (the "Term Loan") with Alberta Investment Management Corporation ("AIMCo"). The Term Loan bore annual interest at 9.5% and matured on the earliest of the closing of the acquisition by Pieridae and March 31, 2022. Proceeds from the Term Loan were used to repay Ikkuma's existing syndicated credit facility of \$4 million and proceed with Ikkuma's flow-through drilling program of \$12 million to be spent by December 31, 2018. As a result of completing the Term Loan with AIMCo and repaying all outstanding bank debt, Ikkuma terminated its amended and restated syndicated credit agreement with its banking syndicate.

DEVELOPMENTS IN 2018

The following is a summary description of the major events which influenced the general development of Pieridae, and which are material to the current business of the Corporation, for the financial year completed on December 31, 2018.

Appointment of Financial Advisors

On February 27, 2018, Pieridae announced it had engaged Morgan Stanley & Co, LLC and SG Americas Securities, LLC (“SG”) to serve as financial advisors for the Corporation’s Goldboro LNG Project (as hereinafter defined). In August 2018 Pieridae announced the appointment of KfW IPEX-Bank (“KfW”) as an additional adviser to assist it in finalizing a multibillion US dollar untied loan guarantee from the German federal government under its Bundesgarantien für ungebundene Finanzkredite (“UFK”) program. Subsequent to year end the engagement with Morgan Stanley & Co, LLC was terminated on mutually acceptable terms. Pieridae continues to work with SG and KfW on the debt financing of the Goldboro project.

Sale and Purchase Agreement

On May 7, 2018, Pieridae announced that it had entered into a term sheet to negotiate a binding liquefied natural gas (LNG) sale and purchase agreement (“SPA”) to supply Canadian-sourced liquefied natural gas to Europe from the Second Train of the Goldboro LNG.

Under the term sheet with Pieridae, the offtaker, AXPO Trading A.G., will purchase up to 1 million tonnes per annum of LNG. This arrangement is proposed to begin from the Start of Commercial Deliveries (currently estimated to be the first quarter of 2023) and last for a 10-year period.

Appointment of New Directors

On June 27, 2018, the Corporation announced the election of M. Kjell Pedersen as a new independent director. On December 21, 2018 the Corporation appointed M. Tim de Freitas as a new non-independent director.

Arrangement with Ikkuma

On August 24, 2018, Pieridae and Ikkuma announced they had entered into a definitive agreement dated August 23, 2018 (the “Arrangement Agreement”) providing for the acquisition by Pieridae of all of the issued and outstanding shares of Ikkuma to be effected by way of a plan of arrangement (the “IKK Arrangement”) under section 193 of the ABCA.

On December 20, 2018, the Corporation and Ikkuma announced that they had completed the arrangement, whereby Pieridae acquired all of the issued and outstanding shares of Ikkuma. Consideration consisted of the issuance of 21.6 million Pieridae common shares valued at approximately \$56.1 million. The completion of the IKK Arrangement provides Pieridae with ownership of an extensive area of producing and gas-prone reserves and resource properties situated primarily in the central Alberta Foothills and northeast British Columbia. It also represents a transformative step in the execution of Pieridae’s integrated business model, as the Corporation shifts to becoming an upstream natural gas producer, in addition to being an LNG development company. Pursuant to the IKK Arrangement, Pieridae acquired the natural gas properties at metrics significantly below the cost of similar reserves and resources in other parts of North America. The Corporation also acquired deep expertise in the exploration and development of these assets, as it looks to expand its portfolio of natural gas assets in the Western Canadian Sedimentary Basin and exploit its properties in Québec. This is expected to provide Pieridae with a long term, competitive advantage for delivering LNG to European and other markets. Pieridae issued 21.6 million shares to close the acquisition. Pieridae shareholders own approximately 71 percent of the Corporation as at December 31, 2018.

On completion of the Arrangement, each shareholder of Ikkuma received, for each common share of Ikkuma, 0.1926 of a common share of Pieridae and 0.1 of a share of ExploreCo (with Ikkuma shareholders holding 100% of ExploreCo upon completion of the Arrangement). The exchange ratio valued the shares of Ikkuma at \$0.86 per share (excluding the value of ExploreCo shares), representing a premium of 188% to the closing price of \$0.30 per share as of August 23, 2018 of Ikkuma common shares on the TSX Venture Exchange. Pieridae shareholders owned approximately 70% of the outstanding shares of the Corporation after completion of the transaction.

Appointment of CFO

Mario Racicot resigned as the chief financial officer of Pieridae on September 1, 2018 and on September 14, 2018 Pieridae announced the appointment of Ms. Melanie Litoski as Chief Financial Officer (“CFO”) of Pieridae. See “Directors and Executive Officers” in this document for additional information regarding Ms. Litoski.

Government of Québec adopts new oil & gas regulation

On September 20, 2018 the Government of Québec adopted new regulations aimed at Québec oil and gas development. The new regulations curtail oil and gas development within a 1,000-metre radius of any urban area. The new regulations adversely impact many of Pieridae’s properties in Québec. Pieridae is working with the Québec government to mitigate and manage these impacts.

Additional Conditional Loan Support from the German Government

Pieridae announced on October 29, 2018 that its proposed financing of upstream activities within the Goldboro LNG Project has received a written confirmation of eligibility in principle for up to US \$1.5 billion of untied loan guarantee by the German federal government under its UFK program (Bundesgarantien für ungebundene Finanzkredite). This confirmation satisfies a condition to completion of the Arrangement and marks an important milestone in advancing the integrated Goldboro LNG Project towards a final investment decision. This prospective US \$1.5 billion German government loan guarantee in relation to the proposed financing of conventional upstream natural gas development is in addition to a like confirmation of UFK eligibility that was previously announced, namely for up to US \$3 billion of prospective German government loan guarantees in relation to the proposed financing of the construction of the Goldboro LNG Facility (excluding Train Two) and all associated facilities.

The terms and conditions of both guarantees are yet to be negotiated in the context of an overall project financing. Given that the rationale of Germany’s UFK program is to enhance security of commodity supply, the actual grant of the guarantees will be subject to, among other things, a commitment that a specified amount of LNG produced annually from Train One of the proposed Goldboro LNG facility over a term of twenty years will be delivered to, and be regasified in, Europe. In 2013, Uniper Global Commodities S.E. entered into a twenty-year agreement with Goldboro Canada LP to purchase approximately 5 million tons per annum of LNG produced from Train One of the proposed Goldboro LNG Facility. This agreement was subsequently amended on February 3, 2016, June 2, 2017 and November 1, 2018 thereby extending the deadline imposed on Pieridae for satisfying certain conditions thereunder. The amendment of this agreement on November 1, 2018 satisfies a condition to the completion of the Arrangement.

Permit to Construct the Goldboro LNG Facility

The Nova Scotia Utility and Review Board issued the permit to construct the Goldboro LNG Facility on November 5, 2018. Pieridae expects to proceed to satisfy each of the associated conditions of that permit and to commence the construction of the Goldboro LNG Facility as soon as a positive financial investment decision is taken by Pieridae. In anticipation of the commencement of construction, Pieridae has engaged

Hatch Ltd. (“Hatch”) to act as its engineering adviser. Hatch was selected due to its core competencies in the conversion, storage, handling and transportation of LNG, which is critical to ensuring a well-thought-out plan that incorporates all aspects of the project site. Hatch has a global network of approximately 9,000 professionals spanning over 150 countries in various sectors including energy and infrastructure. Pieridae is also continuing to engage with First Nations so that the Mi’kmaq people will realize on the opportunities contemplated by the Memorandum of Understanding signed in August 2013.

BUSINESS OF THE CORPORATION

DESCRIPTION OF THE BUSINESS

Pieridae’s mission is to build shareholder value by becoming the first fully integrated independent LNG producer in Canada. The Pieridae’s business activities are centred on the development of the following fields of the energy sector: (a) the production and procurement of Canadian and U.S. natural gas, (b) the processing and liquefaction of that natural gas in the production of LNG at the Goldboro LNG facility, a facility owned by Pieridae and (c) the sale of the LNG to customers for export to international markets and to specific markets in North America (collectively, the “Goldboro LNG Project”). Value will be created to the extent that the price for LNG in international markets (which is often oil influenced) exceeds the cost of the natural gas production and procurement in the North American market and related costs including transportation, liquefaction, shipping and regasification.

Pieridae’s business model is based upon the traditional integrated model for the LNG industry which is characterized by the ownership of both natural gas resources and liquefaction capacity. In terms of liquefaction capacity, the Corporation is developing a natural gas liquefaction facility to be situated on the Atlantic Ocean coast in the Municipality of the District of Guysborough, Nova Scotia (the “Goldboro LNG Project”).

The Goldboro LNG Facility will include (a) one, or possibly two, LNG plants (namely, “Train One” and possibly “Train Two”), each with the capacity to produce approximately 5 million tonnes of LNG annually, (b) a power plant which will generate the electricity required to produce LNG, (c) two LNG storage tanks and (d) marine structures and a jetty which will be equipped to accommodate two LNG carriers, each with a capacity of up to 250,000 m³ of LNG.

This integrated model allows for more flexible management and mitigation of risks along the value chain. This project is at its development stage and Pieridae is seeking to secure sales, procurement, transportation, financing and get all regulatory approval for a final investment decision.

Pieridae’s management team is comprised of an experienced team of professionals in all key operational areas of the organization. See “*Directors and Officers*” in this AIF.

As at December 31, 2018, a total of 63 persons were employed by the Corporation.

SOCIAL AND ENVIRONMENTAL POLICIES

The Corporation has adopted policies relating to health, safety and environmental matters. The Corporation’s objective is to pursue its business strategy while ensuring that its operations meet applicable safety standards and account for environmental and social impacts. Occupational and community health and safety are key concerns in the planning and performance of exploration work. Special attention is also paid to local community and business relationships, as well as environmental protection.

In Alberta, the Corporation's Senior Vice President, Engineering oversees all of the Health, Safety and Environmental policy development, implementation and enforcement. She reports regularly to the Board of Directors.

In Québec, the Corporation has appointed a Head of Community Relations to build ties with the community and strengthen Pieridae's partnerships with the economic and social stakeholders in the regions where it operates. It has also established monitoring committees in a joint initiative with the municipalities having the mandate to facilitate the exchange and dissemination of project information. The committees hold meetings quarterly, or more frequently as needed.

In Nova Scotia, under the Environmental Assessment Approval, the Corporation has established a Community Liaison Committee and Fisheries Advisory Committee. In addition, the Corporation has developed a complaint resolution plan, along with a Mi'kmaq Communication Plan, Community Communication Plan, and Archaeology and Heritage Resources Monitoring and Contingency Plan which are updated periodically.

PROTECTION OF ENVIRONMENT

The Corporation's operations are regulated by laws, act and regulations with respect to, among others, environmental protection. Environmental consequences are difficult to identify, whether in terms of level, timeline or impact. Pieridae is operating in accordance with the applicable environmental protection laws, act and regulations in force.

COMPETITION

The oil and gas and LNG industry are extremely competitive in every aspect. The Corporation competes with other companies that have greater financial resources, more staff and a larger portfolio of facilities than those of Pieridae. Competition could affect the Corporation's ability to acquire properties or capital for its future plans. However, the Corporation believes that its competitive position is equivalent to that of other integrated LNG developing issuers of a similar size and at a similar stage of development.

MARKETING

Pieridae's crude oil, natural gas and NGL production is sold primarily through marketing companies at current market prices. Crude oil contracts are generally month to month and cancellable on 30 days' notice, NGL contracts are generally for a period of up to one year and are cancellable on 90 days' notice and natural gas contracts are generally for one year.

LEGISLATIVE FRAMEWORK

Québec

On December 9, 2016, *Bill 106: An Act regarding the implementation of the 2030 Energy Policy and amending various legislative provisions* was adopted at the Québec National Assembly. This law provides a legislative framework specific to the hydrocarbon's exploration and exploitation activities, which were previously governed by the *Mining Act*.

The *Petroleum Resources Act* and its regulations were published on September 5, 2018 and came into force on September 20, 2018. This new Act and regulations govern the management of land-based oil and gas activities carried out pursuant to exploration, production and hydrocarbon storage licences, the management of hydrocarbon exploration, production and storage licences, oil and gas activities in hydrous environments and regarding fees, duties on the substances withdrawn.

Nova Scotia

In Nova Scotia, all environmental regulations are pursuant to the Environment Act which applies to LNG. Also, other provincial departments such as Lands and Forestry, Transportation and Infrastructure Renewal along with Department of Mines and Energy also have acts and subsequent regulations which apply to or are associated with LNG. Some of these Acts include, but are not limited to, Crown Lands Act, Endangered Species Act, the Highway's Act and the Pipeline Act. In addition, federal Departments and agencies have acts and legislation associated with LNG such as Transport Canada and Department of Fisheries and Oceans. Some of these Acts include Department of Transport Act, Canada Shipping Act and Fisheries Act. Many fall under the umbrella of Nova Scotia Environmental Assessment Approval and associated applications for approval.

New Brunswick

There is presently a government-imposed moratorium on the use of hydraulic fracturing in New Brunswick which effectively prevents any further exploration and development by Production LP of its natural gas resource properties in that province. And while the newly elected government in the province committed to selectively allowing hydraulic fracturing to occur in the province, it has not done so yet.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

British Columbia

In British Columbia, the Oil and Gas Activities Act (the "OGAA") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. Under the OGAA, the British Columbia Oil and Gas Commission (the "BC Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities.

SKILLS AND SPECIALIZED KNOWLEDGE.

The Corporation's business requires specialized skills and knowledge in all of its aspects including, but not limited to, oil and gas operations, LNG facility engineering and construction and LNG operations. The employees, subcontractors and consultants of the Corporation have the required expertise and specialized knowledge to allow the Corporation to carry out its activities.

REORGANIZATION

Other than the PEL Arrangement and the IKK Arrangement, the Corporation and its subsidiaries have not been the object of any reorganization within the three most recently completed financial years. The Corporation completed, during the current financial year, the transfer of the licences it holds for oil and gas exploration in Québec to Pieridae Québec Development Limited Partnership, a limited partnership created on January 2, 2018, of which Pieridae is the limited partner and Pieridae Québec Production Ltd. the general partner.

LICENCES AND PARTNERSHIPS

The recent adoption of the *Petroleum Resources Act* in Québec has had a profound impact on the Corporation's holdings in the province. The multitude of new restrictions contemplated in the legislation caused the Corporation to reevaluate its licence holdings in the province. This exercise resulted in Pieridae relinquishing roughly half of all of its acreage under licence. As of December 31, 2018, the Corporation is reporting licences for and net interests in an area of 4,583 km², however the Québec government has yet to approve these relinquishments. Located in Eastern Québec, the areas retained by the Corporation are considered to offer the most oil potential. Pieridae's territories under licence also offer the potential of discovering natural gas and possibly liquid natural gas.

There are three partnership agreements covering portions of the territories under licences held by Pieridae:

- On the territory covered by the Bourque licences (see map below), Pieridae hold a 51% interest in each of the 4 licences, covering a total area of approximately 750 km². TUGLIQ Energy holds a 4% interest and Ressources Québec holds a 45% interest respectively in such licences.
- Pieridae holds a 20% interest in Pieridae Production LP, which owns certain natural gas resource properties in New Brunswick. Under certain circumstances it is possible for Pieridae to increase this interest to 50%. However, there is presently a government-imposed moratorium on the use of hydraulic fracturing in New Brunswick which effectively prevents any further exploration and development by Pieridae Production LP of its natural gas resource properties in that province. The other partner in Pieridae Production LP is ORLEN Upstream Canada Ltd., an affiliate of Polski Koncern Naftowy Orlen Spółka Akcyjna which is a public corporation listed on the Warsaw stock exchange and is a major Polish oil refiner and petrol retailer with operations in Poland as well as the Czech Republic, Germany and the Baltic States.
- On the territory covered by the Baie-des-Chaleurs–Matapédia and Ristigouche licences (see map below), Pieridae hold a 50% interest in conjunction with Saint-Aubin Énergie S.A.S. (a subsidiary of Maurel & Prom and Maurel & Prom International) which also holds a 50% interest in 13 licences, covering an area of over 1,900 km².
- The remaining licence blocks are wholly-owned by Pieridae.

PROPERTIES OF THE CORPORATION

The Deloitte Reserves Report evaluates the proved and probable crude oil, natural gas and NGL reserves attributable to Pieridae's interest in 100% of its properties in Alberta and British Columbia and the present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. The Deloitte Reserves Report is effective December 31, 2018 and was dated and prepared March 11, 2019. The reserves information was prepared and is presented in accordance with the requirements of the COGE Handbook and NI 51-101. All of Pieridae's reserves are held by its wholly-owned subsidiary, Ikkuma Resources Corp.

Supplement disclosure of the Corporation's contingent and prospective resources has been included as Appendix A to this Annual Information Form and was prepared based on the Resource Reports.

In preparing the Deloitte Reserve Report and the Resource Reports, each of Deloitte and Sproule obtained information from Pieridae, which included land, well and accounting (product prices and operating costs) information, reservoir and geological studies, estimates of on-stream dates, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation and upon which the Deloitte Reserve Report and Resource Reports are based, was obtained from public records, other operators and from Deloitte and Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Deloitte and Sproule as represented.

DESCRIPTION OF THE PROPERTIES

The Corporation's land holdings as of December 31, 2018, are located in the provinces of Alberta, British Columbia, Saskatchewan, Québec and New Brunswick. In total, such lands cover an area of 2,220,827 acres on a gross basis and 1,824,485 acres on a net basis (Table 1).

Table 1: Land Holdings

<i>Area</i>	Working Interest (%)	Gross Acres	Net Area
<i>British Columbia Foothills</i>	72	27,013	19,342
<i>North East British Columbia</i>	90	236,899	212,155
<i>Total British Columbia</i>		263,912	231,497
<i>Central Alberta Foothills</i>	61	298,901	180,938
<i>Northern Alberta Foothills</i>	74	296,280	220,212
<i>Southern Alberta Foothills</i>	18	4,120	741
<i>Southern Alberta</i>	100	4,683	4,683
<i>Total Alberta</i>		603,984	406,574
<i>Saskatchewan</i>		485	485
<i>Total Saskatchewan</i>			
<i>Bourque</i>	51	95,621	48,759
<i>Gaspé (including Halidmand)</i>	100	240,095	119,208
<i>Gastongauy</i>	100	268,080	268,080
<i>Gaspésia</i>	100	345,575	345,575
<i>Edgar</i>	100	48,170	48,170
<i>Marcel Tremblay</i>	100	-	-
<i>Matapédia and Restigouche</i>	50	238,415	238,415
<i>Total Québec</i>		1,316,521	1,150,452
<i>New Brunswick</i>	20	35,927	35,478
<i>Total New Brunswick</i>		35,927	35,478
Total		2,220,827	1,824,485
<i>Western Canada</i>		868,379	638,555
<i>Eastern Canada</i>		1,352,448	1,185,930
Total		2,220,827	1,824,485

The following is a description of the Corporation's principal oil and gas properties, and a description of the Corporation's major plants, facilities and installations.

British Columbia

British Columbia Foothills

The Ojay area is located on the border of Alberta, approximately 100 kms southwest of Grande Prairie, Alberta. As at December 31, 2018, the Corporation had an interest in 27,012 gross (19,342 net) acres in this area. The Corporation has a 40% working interest in a dehydration and compression station and various working interests in gas gathering systems. After compression and dehydration, gas produced from this location flows into Alberta to be processed at the Narraway Gas Plant.

Northern British Columbia

The Deep Basin area includes assets in the Sierra and Ekwan areas roughly 45km east of Fort Nelson, British Columbia stretching 85 km east towards the Alberta border and as was acquired as part of the 2017 acquisition from Husky. As at December 31, 2018, the Corporation had an interest in 236,899 (212,155 net) acres in this area. The Sierra asset consists of ~25mmcf/d of production from the Pine Point formation and is currently shut-in due to infrastructure constraints. Ekwan is currently producing ~7.5mmcf/d from the Jean Marie formation into the TCPL Nova system.

Alberta

Central Foothills

This area consists of the majority of the lands and assets acquired by the Corporation in 2017. Geographically moving in a south east trend from Hinton, Alberta to Lundbreck, Alberta near the Crowsnest Pass. The area includes existing oil production as well as oil and liquids rich opportunities. As at December 31, 2018 the Corporation had an interest in 298,901 gross (180,938 net) acres within this area. Along with the significant land holdings the Corporation has an interest in several large dehydrators and compressors along with the pipeline infrastructure whereby it is able to transport production to the Ram River Gas Plant and NOVA sales meter without incurring third party disruption.

Northern Foothills

This area starts at the Alberta and British Columbia border approximately 100kms southwest of Grande Prairie, Alberta and continues southeast to approximately 30kms east of Grande Cache, Alberta. As at December 31, 2018, the Corporation had an interest in 296,280 gross (220,212 net) acres in this area representing a 74% average working interest. The Corporation has four dehydrators, various compressor stations and gas gathering systems, having working interests between 28% and 59%. The Corporation also has a 7.5% interest in the 135 MMcf/d Narraway Gas Plant and a 35% interest in the 25 MMcf/d Copton Gas Plant located in this area.

Southern Alberta Foothills

The Southern Alberta Foothills asset extends from the town of Rocky Mountain House, South to lands near the town of Turner Valley. As at December 31, 2018, the Corporation had an interest in 8,803 gross (5,423 net) acres representing a 52% average working interest. It includes ownership in approximately 140km of pipeline, compression, and dehydration in the Burnt Timber Raw Gas Gathering System and the surrounding gas field. Along with small percentage ownership in numerous non-operated sites (less than 20%) at Benjamin, Jumping Pound, Moose Mountain and further south to the Waterton lakes area.

Québec

On May 6, 2008 the Corporation signed a comprehensive agreement that amended a prior agreement with Junex Inc. (“Junex”) pertaining to the Gaspé and Gastonguay properties. Under this agreement, the Corporation acquired a 100 percent interest over an area of 6,043 km² on these properties, subject to royalties varying from 0.5 percent to 2.5 percent on the future production of hydrocarbons. Also, under the agreement, the Corporation and Junex agreed to become 50/50 partners in a block of licences covering an approximate area of 291 km², with Junex acting as operator. On this same date a second agreement (the “Haldimand Joint Operating Agreement” or “JOA Haldimand”) defined a development area of 9 km² around Haldimand N°1 well, which was held as to a 45 percent interest by each of the Corporation and Junex with Gastem holding the remaining 10 percent (the “Haldimand Project”). Some licences for these properties are subject to royalties of 5 percent.

On July 30, 2009, the Corporation became the operator of the Haldimand Project, assuming control from Junex as per an amendment to the Haldimand Joint Operating Agreement dated July 22, 2009. As part of the amending agreement, the Corporation also acquired from Junex an additional 9 percent interest in a block of licences covering 291 km² (the “Haldimand Joint Lands”) after drilling the Haldimand N°2 well and doing additional work on the Haldimand N°1 well. As of October 1, 2009, the Corporation also acquired Gastem’s 10 percent working interest in the Haldimand Joint Lands. The Corporation’s interest in the Haldimand Project thus increased to 64 percent.

On June 6, 2010, a further agreement was concluded with Junex, whereby the limits of some jointly held licences in the Gaspé area were modified with the approval of the regulatory authorities and the Haldimand Joint Lands were divided equally amongst the partners. Junex kept the modified permit 2005RS120, adjacent to its Galt Property while the Corporation kept the areas located closer to the Haldimand Project.

On December 8, 2010, Québénergie acquired an interest in 11 whole PG licences, one full RS permit, and a portion of RS permit (2009RS112). Québénergie obtained a 32 percent working interest in the Haldimand Joint Lands, which is 50 percent of the Corporation’s original 64 percent working interest. The interest is less of royalties payable to third parties, which amounts vary by permit.

On December 20, 2011, the Corporation announced that together with its partner Québénergie, they purchased all of the interests held by Junex in the Haldimand Joint Lands. With this transaction the Corporation and Québénergie acquired 100% ownership of the deposit with each owning equal share in such deposit and the surrounding properties.

On October 23, 2017, the Corporation bought back Québénergie's interest in the Haldimand discovery area and the 13 exploration permits of the Gaspé Property (Block). Following this transaction, the Corporation has increased its working interest to 100% in the Haldimand area (13 exploration permits).

The licences issued by the Government of Québec give the Corporation the exclusive right to undertake oil and gas and underground reservoir exploration work for an initial five-year period, with the possibility of further annual renewals for another five years, provided certain obligations are fulfilled. These obligations met each year. The minimum required expenditure must be equivalent to \$0.50 per hectare the first year. The minimum expenditure increases by \$0.50 per hectare in each subsequent year, reaching \$2.50 per hectare in the fifth year. For each additional renewal, the rental fee is fixed at \$0.50 per hectare and the work obligations are equivalent to \$2.50 per hectare. In June 2011, the Québec National Assembly adopted the Act to limit oil and gas activities (Bill 18) (amended in June 2014) which provides that until the adoption of a statute dealing with oil and gas activities or a date determined by the Government of Québec, oil and gas activities in the St. Lawrence River upstream of Anticosti Island and on the islands situated in that part of the river are prohibited. Holders of licences to explore for petroleum, natural gas and underground reservoirs are exempted from performing the exploration work required by law and the terms of such licences are suspended.

For the Québec exploration licences, the Corporation expended \$1,717,423 in 2018 as exploration expenses and \$282,098 in licence fees. The exploration expenses already incurred over the licences are sufficient to meet the minimum work obligation for the next fiscal year that would have been applicable, notwithstanding Bill 18.

New Brunswick

On March 4, 2013, Former Pieridae entered into an agreement with Contact Exploration Inc. (subsequently Kicking Horse Energy Inc.) to establish PPLP in order to acquire and develop natural gas resources in New Brunswick. As at January 1, 2014, Former Pieridae, as a limited partner, had a 16.98% interest in PPLP and made no further contributions to PPLP during that year. During 2015 Former Pieridae invested an additional \$750,000 in PPLP and increasing its ownership interest to 20%. Pieridae is entitled to contribute an additional \$14,125,000 to PPLP prior to any further funding by the other partner, and to thereby increase its ownership in PPLP to 50%. In late 2015 ORLEN Upstream Canada Ltd. acquired Kicking Horse Energy Inc.

There is presently a government-imposed moratorium on the use of hydraulic fracturing in New Brunswick which effectively prevents any further exploration and development by PPLP of its natural gas resource properties in that province.

As of December 31, 2018, the Corporation held a 20% interest, as a limited partner, in PPLP and held a 50% interest, as a shareholder, in PPLP's general partner, Pieridae Production GP Ltd. The Corporation's interest in PPLP and in Pieridae Production GP Ltd. are accounted for in the Corporation's consolidated financial statements using the equity method. For more information, refer to note 16 to the Consolidated Financial Statements of the Corporation for the year ended December 31, 2018 filed on SEDAR.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2018 in which Pieridae has an interest.

TABLE 2: Oil and Gas Wells

<i>Location</i>	Producing				Non-Producing				Service Wells	
	Oil		Natural Gas		Oil		Natural Gas			
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
<i>Alberta</i>	-	-	299	177	3	3	150	101	-	-
<i>British Columbia</i>	-	-	108	99	-	-	52	43	-	-
<i>Sask</i>	-	-	-	-	-	-	9	9	-	-
<i>Québec</i>	-	-	-	-	9	7	-	-	-	-
<i>Total</i>	-	-	407	276	12	10	211	153	-	-

(1) "Gross" wells mean the number of wells in which Pieridae has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells mean the aggregate number of wells obtained by multiplying each gross well by Pieridae's percentage working interest therein.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of crude oil, NGL and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only. The recovery and reserve estimates of the crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with Pieridae's assets may vary from the information presented herein and such variations could be material. See "Risk Factors" in this AIF.

The following tables, based on the Deloitte Reserves Report, show the estimated share of Pieridae's oil, natural gas and NGL reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast price and cost assumptions. All evaluations of the present worth of estimated future net revenue in the Deloitte Reserve Report are stated after provision for estimated future capital expenditures, both before and after income taxes, but, except where otherwise indicated, prior to indirect costs, well abandonment and disconnect costs and surface lease reclamation costs and do not necessarily represent the fair market value of the reserves.

Throughout the following summary tables differences may arise due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A:	Disclosure of Contingent Resources Data and Prospective Resources Data
Appendix B:	NI 51-101 Form F2 Report on reserves data by independent qualified reserves evaluator (Deloitte)
Appendix C:	Form 51-101F2 Report on contingent resources data and prospective resources data by independent qualified reserves evaluator (Sproule)
Appendix D:	Form 51-101F3 Report of Management and Directors on Oil and Gas Disclosure
Appendix E:	Definitions Used for Reserve and Resource Categories

The following table summarizes Pieridae's oil and gas reserves as of December 31, 2018 based on forecast price and cost assumptions.

TABLE 3: Summary of Oil and Gas Reserves as of December 31, 2018 ⁽¹⁾

<i>Reserves Category</i>	<i>Reserves</i>					
	Light/Medium Crude Oil		Conventional Natural Gas ⁽¹⁾		Natural Gas Liquids	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbbl)	Net (Mbbbl)
<i>Proved</i>						
<i>Developed</i>	-	-	353,818	311,886	1,026	698
<i>Producing</i>						
<i>Developed Non-</i>	-	-	112,232	92,647	29	20
<i>Producing</i>						
<i>Undeveloped</i>	-	-	30,347	27,306	16	13
<i>Total Proved</i>	-	-	496,397	431,839	1,071	731
<i>Total Probable</i>	-	-	174,099	147,114	286	203
<i>Total Proved plus Probable</i>	-	-	670,496	578,953	1,357	934

(1) Natural gas volumes include associated, and non-associated gas.

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Pieridae's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2018.

TABLE 4: Summary of Net Present Values of Future Net Revenue as of December 31, 2018 ⁽¹⁾

<i>Reserves Category ⁽²⁾</i>	Before Income Tax, Discounted at (%/year)					After Income Tax, Discounted at (%/year)					Unit Value Before Income Tax, Discounted at 10%/year
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	
<i>Proved</i>											
<i>Developed</i>	530,599	339,834	245,036	189,591	153,673	441,679	291,061	214,833	169,466	139,582	4.65
<i>Producing</i>											
<i>Developed Non-</i>	104,062	67,302	45,543	31,774	22,568	70,925	44,427	28,912	19,195	12,764	2.95
<i>Producing</i>											
<i>Undeveloped</i>	31,514	19,469	11,812	6,774	3,343	23,158	13,583	7,495	3,493	775	2.59
<i>Total Proved</i>	666,175	426,605	302,391	238,138	179,584	535,762	349,071	251,240	192,154	153,121	4.16
<i>Total Probable</i>	355,621	591,093	396,088	288,829	222,310	795,600	469,600	319,999	236,777	184,622	3.79
<i>Total Proved plus Probable</i>	1,021,796	591,093	396,088	288,829	222,310	795,600	469,600	319,999	236,777	184,622	4.07

(1) Future net revenue estimated using forecast prices and costs – see “pricing Assumptions – Forecast Prices and Costs – December 31, 2018” in this AIF.

(2) Values reflect abandonment and reclamation costs for all existing wells assigned reserves and for all future locations assigned reserves in the Deloitte Reserves Report in the aggregate amount of \$42 million (undiscounted) for total proved reserves and \$48 million (undiscounted) for total proved plus probable reserves.

TABLE 5: Total Future Net Revenue (Undiscounted) as of December 31, 2018 ⁽¹⁾

<i>Reserves Category</i>	Revenue ⁽²⁾ (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\$)
<i>Proved Reserves</i>	1,882,993	181,002	940,785	53,367	41,664	666,175	130,412	535,763
<i>Proved plus Probable Reserves</i>	2,742,131	275,724	1,337,577	59,400	47,633	1,021,796	226,186	795,610

(1) Future net revenue estimated using forecast prices and costs – see “pricing Assumptions – Forecast Prices and Costs – December 31, 2018” in this AIF.

(2) Revenue includes product revenue and other income from facilities, wells and corporate if specified.

TABLE 6: Future Net Revenue by Product Type as of December 31, 2018 ⁽¹⁾

<i>Reserve Category</i>	<i>Product Type</i>	Future Net Revenue Before Income Taxes (discounted at 10%/year) (M\$)	Unit Value Before Income Taxes (discounted at 10%/Year) (\$/BOE)
<i>Proved Reserves</i>	Conventional Natural Gas (including associated by-products)	302,391	4.16
<i>Proved Plus Probable Reserves</i>	Conventional Natural Gas (including associated by-products)	396,088	4.07

(1) Future net revenue estimated using forecast prices and costs – see “pricing Assumptions – Forecast Prices and Costs – December 31, 2018” in this AIF.

PRICING ASSUMPTIONS

Forecast Prices and Costs - December 31, 2018

Deloitte employed the following pricing, exchange rate and inflation rate assumptions in estimating Pieridae’s reserves data using forecast prices and costs as of December 31, 2018.

TABLE 7: Canadian Domestic Forecast

	Light Oil	Natural Gas	Natural Gas Liquids				
<i>Year</i>	Canadian Light Sweet Crude ⁽²⁾ 40° API (\$Cdn/Bbl)	Alberta AECO (\$Cdn/Mcf)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)	Edmonton Pentanes Plus (\$Cdn/Bbl)	Operating Cost Inflation Rate (%/Year)	Exchange Rate (\$US/\$Cdn)
<i>Historical</i>							
2013	93.36	3.17	38.54	77.44	103.52	0.9%	0.972
2014	94.00	4.50	42.93	59.43	101.47	1.9%	0.906
2015	57.00	2.69	5.35	33.70	55.15	1.1%	0.783
2016	52.22	2.16	8.71	31.45	52.43	1.4%	0.755
2017	62.11	2.16	27.56	40.96	62.85	1.6%	0.771
2018	75.39	1.61	29.54	45.93	81.62	2.3%	0.784
<i>Forecast</i>							
2019	66.93	1.80	27.00	39.40	62.65	0.0%	0.758
2020	74.99	2.23	33.43	50.75	70.96	2.0%	0.776
2021	79.71	2.63	38.67	58.51	75.67	2.0%	0.780
2022	82.91	2.94	41.25	64.26	78.42	2.0%	0.800
2023	86.33	3.16	43.56	68.00	81.14	2.0%	0.793
2024	88.28	3.31	44.63	69.50	82.98	2.0%	0.806
2025	90.35	3.45	45.67	71.13	84.95	2.0%	0.806
2026	92.60	3.54	46.86	72.84	87.09	2.0%	0.806
2027	94.48	3.62	47.85	74.33	88.86	2.0%	0.806
2028	96.41	3.71	48.88	75.84	90.68	2.0%	0.806
2029	98.32	3.77	49.90	77.35	92.48		

Escalation rate of 2% thereafter

- (1) Forecast prices were estimated using the average of the escalated price forecasts of four independent reserve evaluators, namely Deloitte, GLJ Petroleum Consultants Ltd., McDaniels & Associates Consultants Ltd. and Sproule Associates Limited.
- (2) Edmonton Par prior to 2014.

Pieridae's weighted average realized sales prices for the year ended December 31, 2018 (including Ikkuma results to December 20, 2018) were \$66.20/bbl for oil, \$53.35/bbl for NGLs and \$1.56/Mcf for natural gas, before derivative financial instruments.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

As at December 31, 2017, Pieridae had no reserves. Pieridae only acquired reserves via the acquisition of Ikkuma Resources Corp. on December 20, 2018. Ikkuma remains a wholly-owned subsidiary of Pieridae. Accordingly, there is no reconciliation provided to December 31, 2017.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Deloitte in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves associated with Pieridae's assets are planned to be developed over the next two to three years.

In some cases, it will take longer than two to three years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion, or to changes in geological interpretation, including reservoir continuity and quality); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors" in this AIF.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Pieridae's reserves are evaluated by Deloitte, an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Pieridae's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material. See "Risk Factors – Reserves Estimates" in this AIF.

Pieridae estimates the total cost of future abandonment and reclamation for its existing wells, associated production facilities and infrastructure and the expected timing of the costs to be incurred in future periods. The Corporation has a process for estimating these costs, which considers past experience, applicable current regulations, technology and industry standards, actual and anticipated costs, the type and depth of the well (or the nature and size of the facility), and the geographic location. Pieridae expects to incur abandonment and reclamation costs on 604 gross (384 net) wells, comprising currently producing, non-producing and service wells. As at December 31, 2018, the Corporation has estimated its share of the total abandonment and reclamation costs for its existing wells and facilities to be \$216.4 million undiscounted (approximately \$58.3 million discounted at 10%), of which Pieridae expects to pay approximately \$23.2 million over the next five financial years.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Pieridae's proved plus probable reserves, approximately \$48 million has been deducted in estimating the future net revenue in the Reports, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

FUTURE DEVELOPMENT COSTS

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below, using forecast prices and costs.

TABLE 8: Future Development Costs ⁽¹⁾

Undiscounted Forecast Prices and Costs		
<i>Year</i>	Proved Reserves (M\$)	Proved Plus Probable Reserves (M\$)
2019	1.2	1.2
2020	51.8	55.2
2021	0.3	0.3
2022	-	-
2023	-	2.7
<i>Remaining Years</i>	-	-
Total Undiscounted	53.3	59.4

(1) Future net revenue estimated using forecast prices and costs – see “pricing Assumptions – Forecast Prices and Costs – December 31, 2018” in this AIF.

Pieridae expects to fund the development costs of these reserves through a combination of the funds available from internally generated cash flow, non-core asset dispositions and the issuance of new equity and/or debt where and when it believes appropriate.

There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributable in the Reports. Failure to develop those reserves could have a negative impact on Pieridae's future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Pieridae does not anticipate that interest or other funding costs would make further development of any of Pieridae's assets uneconomic.

See “Risk Factors – Substantial Capital Requirements; Liquidity” and “Reserve Estimates” in this AIF.

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets forth the gross and net acres of unproved properties held by Pieridae as at December 31, 2018 and the net area of unproved property for which Pieridae expects its rights to explore, develop and exploit to expire during the next year. Pieridae has an 85% working interest in its undeveloped land.

TABLE 9: Unproved Properties – Undeveloped Land

<i>Location</i>	Gross ⁽¹⁾ (Acres)	Net ⁽²⁾ (Acres)	Net Area to Expire in 2019
<i>Western Canada</i>	515,621	401,337	62,832
<i>Eastern Canada</i>	1,351,168	1,184,890	-
Total	1,866,789	1,586,227	62,832

(1) “Gross Acres” are the total acres in which Pieridae has or had an interest.

(2) “Net Acres” is the aggregate of the total acres in which Pieridae has or had an interest multiplied by Pieridae’s working interest percentage held therein.

There are no costs or work commitments associated with Pieridae’s Western Canada non-producing properties except for annual lease rental payments. Pieridae’s Québec non-producing properties area all subject to annual licence fees and work obligations. However, the work commitment obligation was suspended in June 2011 upon the imposition of the Québec government’s moratorium on oil and gas exploration and development activity in the province. Pieridae had complied with the requirement to that point. It is not clear when this moratorium will be lifted.

EXPLORATION LICENCES

Gaspésia Property

This block is 100 percent owned by the Corporation and is the western-most block located on the Gaspé Peninsula. It was acquired in 2002 as seven oil and gas exploration licences having a total surface area of 137,000 hectares (Table 10). The licences were converted to underground storage exploration licences (RS) as of April 28, 2009, thus extending their life. The block covers a part of the Connecticut Valley – Gaspé Synclinorium, showing a thick Silurian-Devonian sedimentary sequence lying over a highly deformed Cambrian-Ordovician substratum.

TABLE 10: Description of Property - Gaspésia

<i>Property</i>	Permits	Acquisition Date	Gross Area (Acres)	Working Interest (%)	Net Area (Acres)
<i>Gaspésia - Property Licences</i>	2009RS226	04/28/2009	48,080	100%	48,080
	2009RS228	04/28/2009	46,875	100%	46,875
	2009RS229	04/28/2009	52,973	100%	52,973
	2009RS230	04/28/2009	44,253	100%	44,253
	2009RS231	04/28/2009	51,755	100%	51,755
	2009RS232	04/28/2009	51,888	100%	51,888
	2009RS236	04/28/2009	49,753	100%	49,753
	Total		345,575		345,575

The Gaspésia Block is located in the northern half of the Connecticut Valley – Gaspé Synclinorium basin where important anticlinal structures and numerous fault traps are interpreted from surface geology and are also observed on existing seismic data within the Devonian and Silurian sections. Based on available geological, geochemical and geophysical data, this property has interesting gas and oil potential worthy of further exploration work. Thermal maturity studies indicate that the sedimentary section in the general area is gas prone but, locally, in the north-central part, it could still be in the oil window.

Following a geochemical survey by Vista Geosciences in 2009, the Corporation carried out a surface geochemical survey using a technology developed by Gore. The survey was conducted in February 2011. A detailed plan was developed to cover a significant lead found in Permit 2009RS228 with a pseudo-3D seismic survey. The objective of the survey is to confirm the existence and size of the prospect. At the end of the reporting period, a geophysical permit had been obtained. The Corporation has not conducted any major activities over the Gaspésia Property during the fiscal year ended December 31, 2014 as it has given higher priority to Anticosti projects and Haldimand projects. Work performed in the Matapédia Project to the south has tested a major anticline with a significant extension within the Gaspésia Property.

A 169.5 km² Pseudo 3D seismic survey is planned to define a major structure mapped with already acquired 2D seismic lines. The new survey is designed to confirm the structural closure. 1,090 km of Airborne Hydrocarbon Geochemical Sensing System survey and optional 1,194 km of Airborne Electromagnetic Survey are also planned to confirm the prospectively of this feature.

Though it was planned that those surveys would be acquired in 2017, the provincial permits necessary to proceed were not obtained.

The 2018 exploration budget had been authorized by management and the Corporation was waiting for the legal authorizations in order to proceed. Again, due to the government-imposed moratorium, the permits were never received, and the work did not take place. Given positive results, the drilling of an exploratory well is tentatively forecast for the 2019 drilling season. The main objectives are the Val-Brilliant Silurian sandstones and Sayabec Silurian carbonates. This is a dry gas prospect.

Edgar Property

This property is 100 percent owned by Pieridae and consists of three oil and gas exploration licences (PG) acquired in April 2006 (Table 11). The licences were converted to underground storage exploration licences (RS) as of April 28, 2009, thus extending their life. The property is located in the northeastern extension of the Gaspésia Block (Figure 1). Because of the interesting results obtained from a 2007 government thermal maturation study over this area, the Corporation acquired the exploration land over a large domal structure. The thermal maturation results indicate some parts of the property have potential for oil and gas preservation. Table 14 lists the three licences, which cover a total area of 50,010 hectares.

TABLE 11: Description of Property – Edgar

<i>Property</i>	Permits	Acquisition Date	Gross Area (Acres)	Working Interest (%)	Net Area (Acres)
<i>Edgar - Property Licences</i>	2009RS233	04/28/2009	32,985	100%	32,985
	2009RS234	04/28/2009	15,185	100%	15,185
	2009RS235	04/28/2009	-	100%	-
	Total		48,170		48,170

Other than for geochemical sampling performed in February 2011, the Corporation has not conducted any major activities over the Edgar Block recently. Given the greater restrictions associated with the Petroleum Resources Act, and increasing licence fees, the Corporation elected relinquish Permit 2009RS235 in 2018. It also relinquished 8,185 hectares of Permit 2009RS234.

Marcel Tremblay Property

Given the greater restrictions associated with the Petroleum Resources Act, and increasing licence fees, the Corporation elected relinquish both permits for this property in 2018.

Table 12: Description of Property – Marcel Tremblay

<i>Property</i>	Permits	Acquisition Date	Gross Area (Acres)	Working Interest (%)	Net Area (Acres)
<i>Marcel Tremblay - Property Licences</i>	2009RS225	04/28/2009	-	Relinquished	-
	2009RS227	04/28/2009	-	Relinquished	-
	TOTAL		-		-

Matapédia and Ristigouche Property

The Matapédia Property is located south-east of the Lac Matapédia area, adjacent to the Gaspésia Property. The five licences of the property were initially acquired by Gastem in 2009. In 2013 the licences were acquired by the 50/50 joint venture between the Corporation and Saint-Aubin Énergie S.A.S. (Maurel & Prom and Maurel & Prom International).

Hydrocarbon shows have been recorded in the Matapédia sector (seeps in the northern section, microseeps, and subsurface liquid hydrocarbons) which would suggest that the area is favourable for oil, condensate, and dry gas accumulations.

A variety of work has been undertaken in the area since 2001, including seismic surveys (2001, 2009), geochemical surveys, (2007, 2008, and 2009) and an aeromagnetic survey (2011). Some of the rocks in the Matapédia sector represent potential reservoirs, including the Val-Brillant Formation, which is composed of sandstone with partially porous intervals. Shows of hydrocarbons have been recorded in the Val-Brillant Formation. A flat spot was also found in a seismic profile at the Val-Brillant/Sayabec doublet. Hydrothermal dolomites in the Sayabec Formation are another potential reservoir.

In September and October 2013, the Corporation drilled the core hole – La Vérendrye 2013, to confirm the presence of gas indicated by the well Great Plains Noël et al N°1 La Vérendrye drilled in 1972. The new slim hole well was cored through two reservoir targets: the Val Brilliant and the shallower Saint Leon formations.

Several down-hole samples were collected that confirmed the presence of gas in the low porosity sandstone reservoirs. As this was a test well it was abandoned as per regulations. The Corporation will continue to work up the data on this play to estimate the gas in-place and if a portion of this gas can be recovered. The low porosity nature of the reservoirs will most likely require some form of wellbore stimulation.

The Restigouche Property is located in the southern Gaspé Peninsula, on the north shore of Chaleur Bay and is included with the Matapédia Property. The seven licences of the property were initially acquired by Gastem in 2007. In 2013 the licences were acquired by the 50/50 joint venture between the Corporation and Saint-Aubin Énergie S.A.S. (Maurel & Prom and Maurel & Prom International).

Research indicates that some of the Restigouche area would be prospective for oil and condensate, while the other would be prospective for gas. Several formations in this area have been targeted as potential reservoirs, such as the White Head and the La Vieille Formation. The White Head Formation comprises fractured limestones in fresh fractures, emit strong odors suggesting a migration of hydrocarbons. The La Vieille Formation is, in turn, partially composed of hydrothermal dolomites. To the south in New Brunswick, asphaltene-rich solid bitumen (migrabitume) has been found in similar dolomites, indicating that there has been migration of hydrocarbons.

Seismic surveys were conducted in 2003 covering portions of the Restigouche Project area. In 2011, an aeromagnetic survey was conducted and an environmental study in advance of any future drilling. A structure seen on the seismic has been interpreted as a barrier reef complex in the West Point Formation. The reef complex of West Point elsewhere in cores have indicated locally preserved porosity, thus making this structure a potential target. The Corporation has additional studies to complete prior to any exploration drilling. However, due to the greater restrictions associated with the Petroleum Resources Act, and increasing licence fees, the Corporation elected relinquish a number of permits in 2018.

Table 13: Description of Property – Matapédia and Ristigouche

<i>Property</i>	Permits	Acquisition Date	Gross Area (Acres)	Working Interest (%)	Net Area (Acres)
<i>Matapédia and Ristigouche - Property Licences</i>	2009PG578	09/01/2009	17,971	50%	8,986
	2009PG579	09/01/2009	19,295	50%	9,648
	2009PG580	09/01/2009	23,963	50%	11,981
	2009PG581	09/01/2009	6,428	50%	3,214
	2009PG582	09/01/2009	26,434	Relinquished	13,217
	2009PG583	09/01/2009	18,533	-	9,266
	2007PG939	10/23/2007	11,604	Relinquished	5,802
	2007PG940	10/23/2007	14,011	Relinquished	7,006
	2007PG941	10/23/2007	16,928	Relinquished	8,464
	2007PG942	10/23/2007	23,924	Relinquished	11,962
	2007PG943	10/23/2007	22,925	Relinquished	11,463
	2007PG944	10/23/2007	28,121	Relinquished	14,061
	2007PG945	10/23/2007	8,280	Relinquished	4,140
	Total		238,415		119,208

Gaspé and Bourque Property

The Gaspé Property, including Haldimand, is located in the east-central part of the Gaspé Peninsula (Figure 1). Pieridae initially acquired these exploration licences from Junex in 2005 and has concentrated a large part of its exploration to date on this property. As a result of a June 8, 2010 asset exchange agreement with Junex and with the approval of the ministère des Ressources naturelles et de la Faune (MRNF) (Québec), Junex kept the totality of the revised licence 2005RS120 while Pieridae kept the totality of revised licences 2005RS111, 112 and 122 and within licence 2005RS123, all the area outside of the 900 hectares Haldimand Joint Lands. On December 20, 2011, Junex transferred its share on the Haldimand Block (900 ha) to Pieridae/Québénergie. On December 20, 2011, the Corporation announced that together with its partner Québénergie, they purchased all of the interests held by Junex in the Haldimand Joint Lands. On 23 October 2017, the Corporation has bought back Québénergie's interest in the Haldimand discovery area and the 13 exploration permits of the Gaspé Property (Block). With this transaction the Corporation acquired 100% ownership of the deposit with each owning equal share in such deposit and the surrounding properties. At the time the block was then comprised of 16 oil and gas (PG) and 5 underground reservoir (RS) exploration licences, covering some 3,434 km². However, due to the greater restrictions associated with the Petroleum Resources Act, and increasing licence fees, the Corporation elected full and partial relinquishments of a number of permits for this property in 2018 (Table 17).

Table 14: Description of Property – Gaspé and Bourque

<i>Property</i>	<i>Permits</i>	<i>Acquisition Date</i>	<i>Gross Area (Acres)</i>	<i>Working Interest (%)</i>	<i>Net Area (Acres)</i>
<i>Gaspé - Property Licences</i>	2005RS111 ⁽¹⁾	11/21/2005	23,765	100%	23,765
	2005RS112 ⁽¹⁾	11/21/2005	29,955	100%	29,955
	2005RS122 ⁽¹⁾	11/21/2005	41,295	100%	41,295
	2005RS123 ^{(1)&(2)}	11/21/2005	27,345	100%	27,345
	2009PG499 ⁽¹⁾	04/28/2009	26,845	100%	26,845
	2009PG502 ⁽¹⁾	04/28/2009	43,903	100%	43,903
	2009PG503 ⁽¹⁾	04/28/2009	57,788	100%	57,788
	2009PG505 ⁽¹⁾	04/28/2009	37,453	100%	37,453
	2009PG506 ⁽¹⁾	04/28/2009	-	Relinquished	-
	2009PG511	04/28/2009	-	Relinquished	-
	2009PG512	04/28/2009	-	Relinquished	-
	2009PG518	04/28/2009	-	Relinquished	-
	2009PG519	04/28/2009	26,635	100%	26,635
	2009PG520	04/28/2009	5,678	100%	5,678
	2009PG521	04/28/2009	-	Relinquished	-
	2009PG522	04/28/2009	-	Relinquished	-
	Total		240,095		240,095
<i>Bourque - Property Licences</i>	2009PG496 ⁽¹⁾	04/28/2009	23,046	51%	11,751
	2009PG497 ⁽¹⁾	04/28/2009	31,056	51%	15,836
	2009PG498 ⁽¹⁾	04/28/2009	17,279	51%	8,811
	2009PG499 ⁽¹⁾	04/28/2009	24,240	51%	12,361
	Total		95,621		48,759

(1) Subject to a royalty of 5.0 percent on future production

(2) Haldimand underground reservoir licence

The Gaspé Property is characterized by the presence of oil shows (about 60 known sites) in the Devonian sandstones and limestones, which explains the interest in this region by explorers for more than a century. Most of the early work involved shallow drilling and was lacking either a geological description or petrophysical well logs. Since 1970, better knowledge was acquired from the results of 9 wells and more than 600 km of seismic lines (including Pieridae's 105 km). The main exploration targets correspond to fractures zones in the upper Gaspé limestone or Gaspé sandstone. Other potential targets over the property are Siluro-Devonian reef features and Devonian or Silurian hydrothermal breccias in fracture zones near major faults.

As of December 31, 2018, the Corporation has 5 non-producing wells in place on Gaspé property including 3 on Haldimand, one on Tar Point and one on Le Ber. The Corporation also has 4 (2.04 net) non-producing wells in place on Bourque.

Haldimand Project

The Haldimand discovery was made by the Corporation in 2006 with the drilling of Haldimand No.1 which tested oil 53 °API from shaly sandstones within the York River Formation. The formation is characterized by low primary matrix porosity with open fractures. The second well Haldimand No. 2 was drilled in 2009 approximately 1000 meters to the northwest of the discovery well. Following the drilling of Haldimand No. 2, Sproule Associates Limited carried out an audit of the Corporation's resource estimate which classified the oil as a Contingent Resource. The Corporation subsequently drilled a horizontal well Haldimand No.4 drilled in 2014 to further assess the development of the resource using horizontal well technology and has been conducting tests on the horizontal well. A long-term production test on Haldimand No 4 was done in 2016.

The production test on Haldimand 4 resulted in the natural production, without artificial aid, of high-quality oil (API 53). But, even with intersecting the natural fracture network, it was observed that the formation is still with low permeability and productivity. Thus, in order to improve the productivity of the formation, The Corporation is working on developing a stimulation program for the future that would allow for optimal production of the Haldimand reservoir. This program will be presented to the Gaspé citizens' committee as well as representatives from the municipality.

Appendix A presents the range of contingent resources and Petroleum Initially-In-Place estimates for the Haldimand Project as evaluated by Sproule. According to the Reports, the best estimate of the Discovered Petroleum Initially-in-Place (DPIIP) is 87,968 Mbbl. The best's un-risked estimates of the Contingent Resources are 12,354 Mboe (5,373 Mbbl of oil and 41,887 MMcf of conventional natural gas). The contingent resources are sub-classified as "Development Unclassified with a probability of development estimated at 3%. The best risked estimate is 4,571.1 Mboe (1,988.1 Mbbl of oil and 15,498.1 MMcf of conventional natural gas) (Risked = Best*37).

Bourque Project

The Bourque Project was initiated in 2007 and is located in the northwestern portion of the Gaspé Property 30 km east of Murdochville and 50 km west of the town of Gaspé. This property consists of four licences, at the time 95 percent owned by the Corporation.

On August 5, 2008, the Corporation signed a \$20 million farmout agreement with Pilatus Energy Canada ("Pilatus"). This sum was to be invested in exploration and development work for the project. The first phase of the work, a three-dimensional (3D) seismic survey over an area of 65 km², was carried out during the summer of 2008. The seismic data acquired was processed at the end of 2008, with the data quality being very good. The interpretation of this new data was performed in early winter 2009, with the Corporation and its partner identifying several potential drilling targets and building as a result of a first drilling pad on the most promising site.

Unfortunately, the 2008-2009 global economic turmoil affected the partner's ability to assemble the capital required to go ahead with the drilling operations. The Corporation and Pilatus thus agreed to terminate the farmout agreement, with Pilatus keeping a 5 percent working interest in the Bourque Lands and maintaining its participation as shareholder of the Corporation. Subsequently, the holdings of Pilatus were reduced to 1 percent when it failed to meet certain contractual obligations. In January 2017, the Corporation bought back from Pilatus all its rights, titles and interest in the properties.

The Corporation requested and obtained in April 2012 from the Ministry of Natural Resources and Wildlife permits to drill two wells called Bourque N°1 and Bourque N°2. Concurrently, efforts to secure the financing of these two wells came to fruition. In May 2012 the Corporation completed equity financing with Investissement Québec for an amount of \$10 million, and with investors introduced by National Bank Financial and Laurentian Bank for a total of \$5,750,003, such amounts providing sufficient funding to commit to a drilling rig and plan a drilling campaign in the second half of 2012.

In the first well, Bourque N°1, spudded on July 19, 2012, significant gas shows were encountered during the drilling. Eight (8) DST's were run over a gross interval of 1,700 metres.

The platform for the second well, Bourque N°2, was constructed during this period, and the drilling of this well started on October 31, 2012. The main target, a patch reef, was encountered and the well was drilled to a total deep of 2,678 metres. The main target, a pinnacle reef, was encountered at the bottom of the well.

In August 2015, Pétrolia announced that it had completed the reprocessing of the seismic data related to the Bourque Project and that it had developed a program for further technical work to assess the production capacity of the Forillon Formation in Bourque No. 1 and Bourque No. 2.

On November 6, 2015, Pétrolia confirmed the closing of a \$5,150,000 investment, the first phase of financing for the Bourque property. In this investment, the private placement of Ressources Québec reached \$2,881,800. Ressources Québec also invested \$918,200 in the Bourque property through a joint venture set up by the Corporation, with TUGLIQ Énergie. TUGLIQ Énergie's investment in the Bourque property, through the same joint venture, is \$1,350,000.

On July 15, 2016, Pétrolia confirmed the closure of the second phase of funding for the Bourque project by Ressources Québec, acting as agent of the Government of Québec, for a total amount of \$8,500,000. Following the completion of this second phase of financing for the Bourque property, the interests of the various companies in the joint venture amounted to 51.03% for Petrolia, 45% for Ressources Québec, and 3.97% for TUGLIQ Énergie.

A work program was drawn up for the re-entry of Bourque No. 1 and the directional drilling of a new 1,800 m lateral in the prospective zone of the Forillon Formation. This work was to be followed by the drilling of a new Bourque HZ No. 3 well, located on the same drilling pad, with a horizontal drain of 1,500 m to test the northern flank of an anticlinal structure located southeast of the pad. The drilling of the two wells was to be followed by the installation of temporary production equipment to enable the completion and subsequent production tests of both wells.

On September 26, 2016, Pétrolia announced the beginning of the drilling of the Bourque HZ No. 1 R1 (re-entry) well. The lower open hole section of the Bourque No. 1 well was permanently abandoned by setting 4 cement plugs in the 1,693 m to 2,746 m interval. The sidetracked section of the well was initiated by milling a window through the 9⁵/₈" casing of the well, from 1,221 to 1,227 metres

From that window, the well was progressively deviated to the southwest down to measured depth of 1,641 metres (MD) corresponding to a true vertical depth (TVD) of 1,509 metres and the intermediate casing was set at 1,635 m MD (1,505 m TVD). The total measured drilling depth of the horizontal well is 3,450 metres. The drilling of the 1,815 m horizontal drain in the Forillon Formation was followed by logging operations. Completion equipment was installed in preparation for the acidification of the horizontal drain.

The drilling rig was then moved 53 m to the southeast, on the same platform, in order to drill the Bourque HZ No. 3 well. This new horizontal well was drilled to test the Forillon formation at a true vertical depth (TVD) of 1,297 metres. From that depth, a horizontal drain of 1,497 metres length was then drilled through the reservoir up to the total measured depth of 3,075 metres (MD).

After rig release, a coiled tubing unit was mobilized on the site and acidification of the horizontal section of the Bourque HZ No. 1 R1 was done followed by cleanup and tests. Because of the early onset of winter, no stimulation works was completed on Bourque HZ No. 3 well.

Bourque HZ N°1 R1 main results

After having recovered 181 m³ of fluids used during the completion carried out in late 2016, the Bourque HZ No. 1 R1 well experienced, in its initial production period, a decrease of its gas flow to the surface from 40 400 to 4,700 m³/ day after 2 hours 20 minutes and, after 4 hours, down to a flow too small to be measured (TSTM). Its flow was made up of wet gas in which 120 litres of light oil (43.57 ° API) were recovered. The well was then closed for a 27-hour period for pressure buildup. After such period of closure and a 2,620 kPa head pressure, and before the two down-hole recorders were to be put in place, a static pressure gradient survey was performed (wells closed at the surface). This survey showed that the base of the production casing of Bourque HZ No. 1 R1 contains light oil (0.70 kg/l) from the measured depth of 1,625 m located near the entrance of the horizontal drain to the measured depth of 1,471 m (1,439 m TVD) which suggests an oil column at a vertical depth of 66 m. This oil column is topped by low pressure wet gas.

After a further 24-hour period of closure and a rise of head pressure to 3,128 kPa, the well was then put into production on a 6.25 mm (¼") flow-control valve for a period of eight hours. During runoff, the gas flow to the surface reached 5,080 m³/ d to subsequently decrease to 1,180 m³/ d at the end of the test period.

The analysis of the pressure buildup data reveals that the initial reservoir pressure is 9,065 kPa and at the end of the closure period it is 8,833 kPa. The well was subsequently left closed for a final pressure buildup with the two down-hole recorders until May 17, 2017 (3,740 hours). During the recovery of the down-hole recorders, a static pressure gradient survey was performed (wells closed at the surface). This survey indicated that the production casing is filled with light oil (0.72 kg/l) to a measured depth of 693m (686 m TVD), which corresponds to an oil column at a vertical depth of 819 m. This oil column is topped by low pressure wet gas.

The presence of an oil column that pulled up in the casing up to 686 m TVD indicates that Bourque HZ No. 1 R1 Forillon is a reservoir containing light oil and that the amount of associated gas may be less important than initially assessed. A specific depth sampling procedure is required to define the exact mix of light oil and gas condensate.

A diagnostic analysis of the log-log plot-flow regime identification has been performed on the pressure buildup data and a good agreement was obtained by applying a horizontal well in a dual porosity reservoir model. The shape of the derivative pattern suggests that the Bourque HZ No. 1 R1 reservoir is mostly made up of naturally fractured carbonate rocks and blocks of matrix porosity leading up to open fissures.

Bourque Well HZ No. 3 main results

More than 88.3 m³ of fluid was injected in the Bourque HZ No. 3 well during cleanup operations, from the setup of coil tubing on December 16, 2016 up to the end of operations on December 20, 2016. 54.4 m³ of fluid was recovered in storage tanks. The difference, being 33.9 m³, was injected into the formation during these operations.

On December 20, 2016, a one-hour production test with a 6.25 mm (¼") flow-control valve produced flammable gas with an initial flow of 860 m³/d decreasing to a flow too small to be measured. After this production period, two down-hole recorders were lowered. The presence of a gas/fluid interface was detected at about 935 m. The well was then closed for a final pressure buildup until May 17, 2017 (representing 3,580 hours).

On May 17, 2017, during the removal of down-hole recorders, a static pressure survey was performed (wells closed at the surface). This survey shows that production casing is filled with water (1.06 kg/l) up to the measured depth of 536 m, which corresponds to a water column at a vertical depth of 762 m. This water column is topped with non-pressurized gas. Taking into account the open horizontal drain and the water column in the casing, the total volume is estimated at 34.5 m³, which corresponds to the remaining water/brine remaining in the well at the end of the stimulation test. The analysis of pressure buildup data reveals that the initial reservoir pressure of the Bourque HZ No. 3 well is approximately 8,234 kPa.

Appendix A presents the range of contingent, prospective resources and Petroleum Initially-In-Place estimates for the Bourque Project as evaluated by Sproule. According to Sproule's report, the best estimate of the Total Petroleum Initially-in-Place (TPIIP) for the pool volume is 827,000 Mbbl (Table 4). The Discovered Petroleum Initially-in-Place (DPIIP) is estimated at 62,000 Mbbl and the Undiscovered Petroleum Initially-in-Place (UPIIP) is estimated at 765,000 Mbbl.

For Pieridae Working Interest, the Total Petroleum Initially-in-Place (TPIIP) in the pool volume is 422,018 Mbbl. The Discovered Petroleum Initially-in-Place (DPIIP) is estimated for the Company at 31,639 Mbbl and the Undiscovered Petroleum Initially-in-Place (UPIIP) is estimated at 390,380 Mbbl.

The best estimate of the un-risked Contingent Resources for the pool volume is 5,714.7 Mboe (2,241.0 Mbbl of oil, 17,753 MMcf of conventional natural gas and 514.8 Mbbl of NGL). The best estimate of the Company un-risked Contingent Resources is 2,916.2 Mboe (1,143.6 Mbbl of oil, 9,059.6 MMcf of conventional natural gas and 262.7 Mbbl of NGL). The contingent resources are sub-classified as “Development Unclassified”.

The best estimate of the un-risked Prospective Resources in the pool volume is 44,294.2 Mboe (16,062.0 Mbbl of oil, 144,287 MMcf of conventional natural gas and 4,184.3 Mbbl of NGL). The best estimate of the un-risked Company Prospective Resources is 22,603.3 Mboe (8,196.4 Mbbl of oil, 73,629.7 MMcf of conventional natural gas and 2,135.3 Mbbl of NGL). The Prospective Resource is sub-classified as prospective (Prospect).

A 30% chance of development risk (70% chance of not proceeding with development) is assigned by Sproule to Contingent Resources.

A 26% chance of commerciality risk (74% chance of not proceeding with development) is assigned by Sproule to Prospective Resources. This is the product of a 30 percent chance of development risk and a 90 percent chance of discovery risk.

The best estimate of the risked Contingent Resources for the pool volume is 1,714.4 Mboe (672.3 Mbbl of oil, 5,326 MMcf of conventional natural gas and 154.5 Mbbl of NGL). The best estimate of the Company risked Contingent Resources is 874.9 Mboe (343.1 Mbbl of oil, 2,717.9 MMcf of conventional natural gas and 78.8 Mbbl of NGL). The contingent resources are sub-classified as “Development Unclassified”.

The best estimate of the risked Prospective Resources in the pool volume is 11,516.5 Mboe (4,176.1 Mbbl of oil, 37,515 MMcf of conventional natural gas and 1,087.9 Mbbl of NGL). The best estimate of the risked Company Prospective Resources is 5,876.9 Mboe (2,131.1 Mbbl of oil, 19,143.7 MMcf of conventional natural gas and 555.2 Mbbl of NGL). The Prospective Resource is sub-classified as prospective (Prospect).

Haldimand Fairway Project

The Haldimand Fairway Project was conceived during 2008. It includes the areas located to the northwest and southeast of the Haldimand Project, in which Pieridae holds a 100 percent interest.

According to the Corporation these areas present geological characteristics resembling those observed in the Haldimand Field area. During the 2007-2008 financial year, Pieridae invested \$1.2 million in exploration work on this project to identify targets to be drilled. In December of 2008 the Corporation carried out an 83-kilometre 2D seismic program. As a result of this program, the Corporation split the project area into two projects, the first being Tar Point, which is the Southern Haldimand Fairway and constitutes the natural extension of the Pieridae- Haldimand N°1 area to the southeast, and Corte-Real to the northwest.

Tar Point (South)

In the Southern Haldimand Fairway, the results of the 2D seismic, combined with the surface geology and an aeromagnetic survey acquired by Pieridae in 2008, defined two drilling targets. This led to the selection of a site on a structure known as the Tar Point anticline, near Anse-à-Brillant, 18 km southeast of Gaspé. A well drilled on the anticline in 1950, about 2 km northwest of the proposed site, intersected traces of petroleum in the York River Formation (Devonian sandstones), with a strong gas show at the bottom, at a depth of about 2,155 m, in limestones of the Indian Cove Formation. Moreover, in a coastal section less than one kilometre from the proposed site, liquid petroleum has been observed in several open fractures of the York River Formation and in amygdules in a Carboniferous dyke.

The well Pieridae-Tar Point N°1, drilled from October 23 to December 7, 2009, reached a total depth of 2,434 m, intersecting in the process 1536 m of York River Formation, 619 m of Indian Cove Formation and, after going through a fault, drilling through 150 m of Grès de Gaspé. The following information was gathered from this well:

1. The upper section of the York River Formation does not contain any hydrocarbons on account of its shallow burial depth.
2. The lower section of the York River Formation contains indications of light oil with porosity and permeability characteristics similar to those found on the Haldimand Project.
3. In the Indian Cove Formation, two 100 m sections with open fractures have given numerous indications of hydrocarbons.

Following completion, the well is currently shut-in.

A DFIT carried out in November 2011, confirmed the possibility of increasing production with an appropriated stimulation program.

As of December 31, 2018, the Corporation has one non-producing wells in place on Tar Point property.

Corte-Real (North)

In the Northern Haldimand Fairway, the seismic suggest the presence of reefs within the Chaleurs Group. The Northern Haldimand Corridor thus shows similarities to the Bourque Project. Reefal traps are very abundant in the Western Canadian Sedimentary Basin, and also in Ontario and Michigan, which further supports Pieridae's interest in this region. The old seismic data, combined with the new data acquired by Pieridae in 2008, should enable a drilling target to be identified in this area. The present estimate is that a well 2,000 metres deep would be necessary to reach the reef-bearing strata. The Corporation is looking for a partner to help explore this area and exploration of this area will depend on the results of the two Bourque wells.

Gastonguay Property

The Gastonguay Property is located in the east-central part of the Gaspé Peninsula. It is subdivided into 13 oil and gas exploration licences (PG) covering an area of 259,015 hectares (Table 15).

On this property, which is located over large anticlinal structures, very little exploration has been done to date but the presence of oil and gas in fractures has been shown in the Murdochville skarn area in mining cores. Various exploration targets in Devonian and Silurian limestones and sandstones, at depths ranging from 1,000 to 4,000 metres, are expected. One well was drilled in the 1980s to a depth of 1,800 metres on one of the anticlines; however, the deeper targeted Silurian was not reached.

Table 15: Description of Property – Gastonguay

<i>Property</i>	<i>Permits</i>	<i>Acquisition Date</i>	<i>Gross Area (Acres)</i>	<i>Working Interest (%)</i>	<i>Net Area (Acres)</i>
<i>Gastonguay - Property Licences</i>	2009PG494	28/04/2009	-	Relinquished	-
	2009PG495	28/04/2009	58,770	100%	58,770
	2009PG500	28/04/2009	30,310	100%	30,310
	2009PG501	28/04/2009	16,508	100%	16,508
	2009PG507	28/04/2009	38,318	100%	38,318
	2009PG508	28/04/2009	46,670	100%	46,670
	2009PG509	28/04/2009	60,998	100%	60,998
	2009PG510	28/04/2009	16,508	100%	16,508
	2009PG513	28/04/2009	-	Relinquished	-
	2009PG514	28/04/2009	-	Relinquished	-
	2009PG515	28/04/2009	-	Relinquished	-
	2009PG516	28/04/2009	-	Relinquished	-
	2009PG517	28/04/2009	-	Relinquished	-
Total			268,080		268,080

New Brunswick Property

TABLE 16: Description of Property - New Brunswick

<i>Property</i>	<i>Permits</i>	<i>Acquisition Date</i>	<i>Gross Area (Acres)</i>	<i>Working Interest (%)</i>	<i>Net Area (Acres)</i>
<i>New Brunswick - Property Licences</i>	01-Jan	01/01/2014	15,755	100%	15,755
	2001-01-27	02/01/2014	887	100%	887
	01-01/36	03/01/2014	887	100%	887
	01-01/85 ijop	04/01/2014	222	100%	222
	01-01/86	05/01/2014	887	100%	887
	01-Jul	06/01/2014	12,434	100%	12,434
	03-Jul	07/01/2014	1,774	100%	1,774
	04-Jul	08/01/2014	2,661	100%	2,661
Total			35,509		35,509

British Columbia Property

TABLE 17: Description of Property – British Columbia

<i>Area</i>	<i>Working Interest (%)</i>	<i>Gross Acres</i>	<i>Net Area</i>
<i>Ojay</i>	72	27,013	19,342
<i>Total British Columbia Foothills</i>		27,013	19,342
<i>Ekwan</i>	88	203,496	178,920
<i>Sierra</i>	100	33,403	33,235
<i>Total North East British Columbia</i>	90	236,899	212,155
<i>Total British Columbia</i>		263,912	231,497

Alberta Property

TABLE 18: Description of Property – Alberta

<i>Area</i>	Working Interest (%)	Gross Acres	Net Area
<i>Bighorn</i>	71	41,280	29,336
<i>Brown Creek</i>	66	47,641	31,367
<i>Burnt Timber</i>	45	26,560	11,910
<i>Ricinus West</i>	81	22,400	18,042
<i>Stolberg</i>	72	81,760	59,240
<i>West Ansell</i>	42	74,780	31,044
<i>Central Alberta Foothills</i>	61	298,901	180,938
<i>Cabin Creek</i>	56	11,520	6,400
<i>Copton</i>	66	66,560	43,749
<i>Findley</i>	77	92,778	71,798
<i>Kiskiu</i>	43	23,680	10,299
<i>Lynx</i>	100	23,040	23,040
<i>Narraway</i>	76	55,812	42,677
<i>Palliser</i>	100	14,080	14,080
<i>Solomon</i>	100	8,170	8,170
<i>Northern Alberta Foothills</i>	74	296,280	220,212
<i>Jumping Pound</i>	36	480	175
<i>Lundbreck</i>	4	440	18
<i>Moose</i>	17	3,200	548
<i>Southern Alberta Foothills</i>	18	4,120	741
<i>Fort Macleod</i>	100	3,840	3,840
<i>Nanton</i>	100	843	843
<i>Southern Alberta</i>	100	4,683	4,683
<i>Total Alberta</i>		603,984	406,574

EXPLORATION COSTS

In the fiscal year ended December 31, 2018, the Corporation expended \$1.7 million on exploration activities on its permits less exploration subsidies and a partner contribution of \$54 thousand. The Corporation has met all of the required current financial obligations on all permits.

INDUSTRY CONDITIONS

GOVERNMENT REGULATIONS

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. Oil and gas operations are subject to Canadian federal, provincial, territorial and local laws and regulations, which regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation and disposal of oil and gas, oil and gas by-products, waste and other substances and materials produced or used in connection with oil and gas operations. These laws and regulations may change in response to changing economic or political conditions.

Failure to comply with the laws and regulations may result in administrative, civil and criminal penalties, remedial obligations and injunctions that could delay, limit or prohibit certain operations. All laws and regulations are a matter of public record and Pieridae is unable to predict what additional laws, regulations or amendments may be enacted.

PRICING AND MARKETING

Natural Gas

The price of natural gas is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms.

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³ per day) must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short-term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Natural Gas Liquids

In Canada, the price of Natural Gas Liquids ("NGL") sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, prices of competing chemical feed stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGL exported from Canada are subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. NGL may be exported for a term of no more than one year in respect of propane and butane, and no more than two years in respect of ethane, all exports requiring an order of the NEB.

INTERNATIONAL TRADE

The North American Free Trade Agreement and United States-Mexico-Canada Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

On September 30, 2018, after a year of negotiation, the United States, Mexico and Canada reached a new trade agreement to be called the United States-Mexico-Canada Agreement (“USMCA”). This agreement has not yet been ratified, and as such, the current NAFTA agreement remains in force. The Corporation is currently assessing the impacts on this agreement and its activities.

The Comprehensive and Progressive Agreement for Trans-Pacific Partnership

In October 2015, Canada concluded negotiations for a free trade agreement between the members of the Trans-Pacific Partnership ("TPP"), which includes Canada, Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore, the United States and Vietnam. All 12 countries signed the TPP in 2016. However, in 2017, the United States withdrew from TPP and the remaining 11 countries agreed to try to revive the deal without United States participation. On March 8, 2018, representatives from the 11 remaining countries met in Santiago, Chile to sign the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("CPTPP"). When the CPTPP comes fully into force, almost all tariffs between CPTPP member countries are expected to be reduced or eliminated, and non-tariff barriers to trade are expected to be removed.

Other International Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement (“CETA”), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017.

While it is uncertain what effect CETA or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

LAND TENURE

Provincial and federal governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments.

Continuing interests in petroleum and natural gas licences are earned by drilling wells. A lease is proven productive at the end of its initial term by drilling, producing, mapping, being part of a unit agreement or paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond its initial term. The tenure comes to an end when the holder can no longer prove its well is capable of producing oil or gas.

Many jurisdictions in Canada have legislation in place for mineral rights reversion to the Crown of stratigraphic formations that cannot be shown to be capable of production at the end of their primary lease term. In some provinces, energy companies are able to continue lease terms for non-productive lands if certain criteria are met under the relevant legislation.

Certain oil and natural gas mineral interests are privately-owned and rights to explore and produce on such lands are granted by leases on the terms and conditions negotiated between the landowner and the lessee.

Each of the provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or intermediate term of the licence.

PRODUCTION AND OPERATION REGULATIONS

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operations of facilities and pipelines, the storage, injection and disposal of substances, the abandonment and reclamation of well-sites, and the decommissioning and reclamation of facilities and pipelines. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, the Corporation must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

PIPELINE CAPACITY

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity in Canada is constrained. Notwithstanding limited pipeline capacity in Canada, Pieridae projects sufficient capacity for the foreseeable future considering the actual pipeline network with limited improvements.

ROYALTIES AND INCENTIVES

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity and depth, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, inter alia, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2017, the Government of Alberta adopted a "Modernized Royalty Framework" for Alberta (the "MRF"). Wells drilled prior to January 1, 2017 will continue to be governed by the previous "Alberta Royalty Framework" for a period of 10 years until December 31, 2026. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty applies until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length, historical costs and placed proppant). The Pre-Payout royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a royalty rate determined by reference to the current commodity price of the substances the well is producing, with the royalty rate ranging from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are intended, on average, to yield the same internal rate of return as under the previous Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold (40 BOE/d or 345,500m³ of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, were released on April 21, 2016.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to “The New Royalty Framework” (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the “Alberta Royalty Framework” until January 1, 2027.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime was 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 36%. Royalties on NGLs are levied at a flat rate of 30% of the sales volume for propane and butane and 40% for pentanes plus with field condensate at a rate equivalent to oil.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the “IETP”), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017 for a 10-year period until January 1, 2027. Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, which came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources, respectively, in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator (the “AER”).

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50 per hectare for licences and \$7.50 per hectare for leases and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (“old oil”), between October 31, 1975 and June 1, 1998 (“new oil”), or after June 1, 1998 or through an Enhanced Oil Recovery (“EOR”) scheme (“third-tier oil”). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The freehold production tax rate for natural gas liquids is a flat 12.25%.

As of January 1, 2017, all liquid natural gas (“LNG”) facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer’s net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's natural gas low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- The Deep Well Royalty Credit Program provides a royalty credit for natural gas wells against royalties. It is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spudded before September 1, 2009) if certain other criteria are met. It is intended to reflect the higher drilling and completion costs that relate to location specific factors. Since April 1, 2014, the Deep Well Royalty Credit Program has two tiers – “tier one” and “tier two”. The existing Deep Well Royalty Credit Program, as described above, comprises tier two of the program which offers a higher maximum royalty credit and attracts a 3% minimum royalty. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than 1,900 metres if spudded on or after April 1, 2014 and attracts a 6% minimum royalty.
- The Deep Re-Entry Royalty Credit Program provided a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres for horizontal wells and 2,500 metres for vertical wells and a re-entry date subsequent to December 1, 2003. If the well was spudded on or after January 1, 2009, it must have a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres for horizontal wells and 2,400 metres for vertical wells.
- The Deep Discovery Royalty Credit Program provides the lesser of a 3-year royalty holiday or 283,000,000 m3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation.
- The Coalbed Gas Royalty Reduction and Credit Program provides a royalty reduction for coalbed gas wells with average daily production less than 17,000 m3 as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land.
- The Marginal Well Royalty Reduction Program provides a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m3.
- The Ultra-Marginal Well Royalty Reduction Program provides royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m3 per metre of depth for exploratory wildcat wells and less than 11 m3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m3. Horizontal wells that are spudded on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program.
- The Net Profit Royalty Reduction Program provides reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month. The amended regulation applied to royalties starting with the April 2013 production month. The 3% minimum royalty began showing on monthly gas royalty invoices in July 2013.

Nova Scotia

Nova Scotia prescribed royalties on petroleum products range from 2% to 50% according to the article 72(1) of the Offshore Petroleum Royalty Regulations made under Section 23 of the Offshore Petroleum Royalty Act.

Québec

Before September 20, 2018, Québec did not have a legislative and regulatory regime that is specific to the oil and gas industry. Its oil and gas resources were regulated principally under the province's mining laws and regulations pursuant to which royalty rates of 5 to 12.5% of the market value of petroleum and natural gas production apply, depending on the average daily production at the wellhead.

In December 2016, Québec passed An Act to implement the 2030 Energy Policy and amend various legislative provisions. This legislation included the new Petroleum Resources Act, which, once in force on September 20, 2018, replaced existing provisions of the Mining Act and established a licence and authorization system for the development of petroleum resources in Québec. Under Québec's new regulations to the Petroleum Resources Act, the royalty regime remains the same as under the Mining Act and its regulations.

New Brunswick

New Brunswick uses a two-tier royalty regime for natural gas production. The basic royalty rate is equal to the greater of 4% of the wellhead price or 2% of gross revenues. After a project has recovered all its eligible costs and begins to make a profit, the producer must also pay 25% of the excess of revenues over eligible costs.

The royalty rate for NGL is 10% of gross revenues.

ENVIRONMENTAL REGULATIONS

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and disposal, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility, and pipeline sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Under the Jobs, Growth and Long-Term Prosperity Act, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing federal environmental assessment process and replace the NEB with the Canadian Energy Regulator (“CER”). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the “Agency”) would replace the Canadian Environmental Assessment Agency. The types of projects that will be subject to the new impact assessment process are not yet known. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency’s process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a public review before a hearing panel; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government’s interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

Alberta

The AER is the single regulator responsible for all oil and gas development in Alberta. The AER ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Alberta's Integrated Resource Management System ("IRMS") provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "ALUF"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The Alberta Land Stewardship Act (the "ALSA") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licences, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plans to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP") which came into effect on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP established six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and recreation areas will include a restriction that prohibits surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan (“SSRP”) which came into force on September 1, 2014. The SSRP was amended in May 2018. It is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44 percent of the province’s population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

The North Saskatchewan Regional Plan (“NSRP”) is being drafted. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size. The Upper Peace Regional Plan, Lower Peace Regional Plan, Red Deer Regional Plan and Upper Athabasca Regional Plan have not been started.

British Columbia

In British Columbia, the Oil and Gas Activities Act (the “OGAA”) impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. Under the OGAA, the British Columbia Oil and Gas Commission (the “BC Commission”) has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The Environmental Protection and Management Regulation establishes the government’s environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the Petroleum and Natural Gas Act, in conjunction with the OGAA requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, and permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole, and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Nova Scotia

Environmental laws in Nova Scotia are largely set out in the *Environment Act* which applies to LNG activities. Moreover, other provincial departments such as Lands and Forestry along with Department of Mines and Energy also have acts and subsequent regulations which apply to LNG and concern environment. In addition, federal departments and agencies have acts and legislation associated with LNG such as Transport Canada and Department of Fisheries and Oceans. Many environmental regulations fall under the umbrella of the Nova Scotia Environmental Assessment Approval process and applications for approval.

Québec

Environmental laws in Québec are largely set out in the Environment Quality Act, which requires parties looking to conduct certain commercial and industrial activities to first obtain a certification of authorization from the Québec Minister of Sustainable Development, Environment and Parks. The legislation is widely construed so as to include anyone erecting or altering a structure, undertaking to operate an industry, carrying on an activity, using an industrial process or increasing the production of any goods or services if it seems likely that this will result in an emission of contaminants or change the quality of the environment (with some exceptions). The Environment Quality Act applies to the majority of oil and gas operations in Québec.

In September 2017, Government of Québec released new draft regulations to the Petroleum Resources Act. This legislation and its regulations will, once in force, govern all oil and gas activities in Québec. These regulations cover oil and gas development on land and in bodies of water, licences for activities like exploration, development and storage and pipeline construction.

On September 20, 2018, Government of Québec adopted the new legislative and regulatory provisions pertaining to the exploration and exploitation of hydrocarbons in Québec, the Petroleum Resources Act and its regulations.

New Brunswick

The New Brunswick Government's environmental laws are largely set out in its climate change action plan, which was released in December 2016, and the indefinite moratorium on hydraulic fracturing through the "An Act to Amend the Oil and Gas Act".

On February 26, 2016, the NB Commission released its report to the New Brunswick Government, which report sets forth the NB Commission's findings, reviews the potential impact of shale development in New Brunswick and identifies five options available to New Brunswick. These options are: (i) implement a legislated ban on hydraulic fracturing; (ii) maintain the moratorium; (iii) maintain the moratorium until there is in place an enhanced regulatory system, an independent research and monitoring program and sufficient public support to proceed with a government-sponsored exploration program similar to the federal/provincial agreements that led to oil and gas offshore developments in Nova Scotia and in Newfoundland and Labrador; (iv) remove the moratorium all or in part, with an enhanced regulatory system and an independent research and monitoring program; or (v) remove the moratorium with no changes to current regulations.

LIABILITY MANAGEMENT RATING PROGRAMS

Alberta

In Alberta, the AER administers the Liability Management Rating Program (the “AB LMR Program”) to manage the abandonment and reclamation liabilities associated with most conventional upstream oil and gas well and facilities. The Oil and Gas Conservation Act (Alberta) established an orphan fund (the “Orphan Fund”) to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LMR Program if a licensee or working interest participant (“WIP”) becomes defunct. The Orphan Fund is funded by licensees in the AB LMR Program through a levy administered by the AER. The AB LMR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities and pipelines. The AB LMR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the transfer of any well or facility licences from one operator to another. Failure to post a required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LMR Program (the “Changes”) that resulted in an increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affected the deemed parameters and costs used to calculate the ratio of deemed assets to deemed liabilities under the AB LMR Program, increasing a licensee’s deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the abandonment and reclamation liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the “IWCP”) to address the growing inventory of inactive wells in Alberta and to increase the AER’s surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells (“Directive 013”). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

On June 20, 2016, the AER issued Bulletin 2016-16 Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision (“Bulletin 16”) which includes an interim rule that as a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio (“LMR”) of 2.0 or higher immediately following the transfer. If the transfer of the licensee does not improve the purchaser’s LMR to 2.0 (or higher), the purchaser must post a security deposit in order for the AER to approve the transfer of the licences.

In order to clarify and revise the interim rules in Bulletin 2016-16, the AER issued Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("Bulletin 21") on July 8, 2016 and reaffirmed its position that a LMR of 1.0 is not sufficient to ensure that licencees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 2016-21 provided the AER with additional flexibility to permit licencees to acquire additional AER-licensed assets if: (i) the licensee already has a LMR of 2.0 or higher; (ii) the acquisition will improve the licensee's LMR to 2.0 or higher; or (iii) the licensee is able to satisfy its obligations, notwithstanding a LMR below 2.0, by other means. The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement.

The AER's Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with eligibility to hold a licence to drill and operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency or compliance proceedings in the last five years.

British Columbia

In British Columbia, the BC Commission implements the Liability Management Rating Program (the "BC LMR Program"), designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit a required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

CLIMATE CHANGE REGULATIONS

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policies with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of April 17, 2019, 188 of the 197 parties to the convention have ratified the Paris Agreement. Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030.

Additionally, on December 9, 2016, the federal government formally announced the Pan-Canadian Framework on Clean Growth and Climate Change (the "PCF"). As a result, the federal government implemented a Canada-wide carbon pricing scheme beginning on April 1, 2019. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government has imposed a price on carbon of \$20 per tonne on any province or territory which failed to implement its own system by 2018. This amount will increase by \$10 annually until it reaches \$50 per tonne in 2022 at which time the program will be reviewed.

In early 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the “GGPPA”). The GGPPA reinforces the approach taken in the PCF and only applies in provinces or territories that do not otherwise implement an adequate provincial or territorial carbon pricing regime.

To complement carbon pricing, a Clean Fuel Standard is being developed by the federal government with the objective of achieving annual reductions of 30 Mt of GHG emissions by 2030. The standard would require reductions in the carbon footprint of the fuels supplied in Canada, based on life cycle analysis. The approach will not differentiate between crude oil types produced in or imported into Canada. This standard is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings.

In general, there is uncertainty with regard to the impact of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on Pieridae’s operations and cash flow.

Alberta

Alberta enacted the Climate Change and Emissions Management Act (the “CCEMA”) on December 4, 2003, amending it through the Climate Change and Emissions Management Amendment Act, which received royal assent on November 4, 2008. The accompanying regulations include the Specified Gas Emitters Regulation (“SGER”), which applies to facilities emitting more than 100,000 tonnes of GHG emissions.

On January 1, 2018, the SGER was replaced with the Carbon Competitiveness Incentive Regulation (the “CCIR”), with a three-year phase-in period. Similar to the SGER, the CCIR applies to facilities emitting more than 100,000 tonnes per annum. The CCIR is designed to incent CCIR facilities to reduce GHG emissions through improving performance by establishing product-based performance standards (also called output-based allocations) across all industries. The 2019 carbon levy will remain at \$30/tonne.

Alberta Climate Leadership Plan

In November 2015, the Alberta government announced its climate leadership plan (the “CLP”). On June 7, 2016, the Climate Leadership Implementation Act (“CLIA”) was passed into law. The CLIA enacted the Climate Leadership Act (“CLA”) introducing a carbon tax on all sources of GHG emissions, resulting from the combustion of fuels for heating and transportation on consumers and larger facilities on operations not otherwise subject to the SGER (and as of January 1, 2018, the CCIR). An initial economy-wide levy of \$20 per tonne was implemented on January 1, 2017 and increased to \$30 per tonne in January 1, 2018. All fuel consumption, including gasoline and natural gas, is subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit.

There are certain exemptions to the carbon levy imposed by the CLA. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers are exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower methane emissions by 45 percent by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

On April 16, 2019 a new government was elected in Alberta. The new government has given indication that they intend to eliminate the Carbon tax.

British Columbia

British Columbia enacted a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is \$35 per tonne of CO₂ equivalent.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the “GGIRCA”) and its associated regulations that came into force. The GGIRCA sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures.

In May 2018, the Government of British Columbia updated its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 40% from 2007 levels by 2030, 60% by 2040 and 80% by 2050. The Plan includes various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a target of a 45% reduction in fugitive and vented emissions by 2025 relative to 2014 levels. On January 16, 2019 the BC Commission introduced new regulations that will come into effect on January 1, 2020 and will require mandatory leak detection and repair and equipment performance standards.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050 and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

Nova Scotia

Amendments to the Environment Act were passed in October 2017 and were proclaimed on February 15, 2018. Nova Scotia then adopted regulations on GHG emissions. The provincial rules related to the GHG reporting are set out in Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulations and Standards of Quantification, Reporting and Verification of Greenhouse Gas Emissions. The first set of regulations is now in effect and requires certain companies to report their GHG emissions and get them verified by a third party.

The amendments also allow government to create the cap and trade program and regulations to support it. Such cap and trade regulation would be designed to reduce greenhouse gas emissions by attaching a price or cost to emissions creating an incentive to reduce GHG emissions. The government of Nova Scotia has proposed a cap and trade program which is still under development and may come into force in 2019. Until the government finalizes the program the impact to the business cannot be quantified.

Québec

Québec operates under its 2013-2020 Climate Change Action Plan, which calls for a 20% reduction in GHG emissions below 1990 levels by 2020. As part of this plan, the Québec Government passed the Environmental Quality Act, which empowers the government to set emission limits, establish reporting requirements for GHG emitters and establish a cap-and-trade system.

Regulations to the Environmental Quality Act established Québec's cap-and-trade system in 2012. Under this system, the province sets GHG reduction targets and businesses that emit 25,000 tonnes or more of carbon dioxide equivalent per year must cover their GHG emissions with an equivalent number of emissions allowances (in the form of emission units, offset credits or early reduction credits). Québec awards a number of free emission units, primarily to industrial emitters exposed to foreign competition. However, the number of units allocated free of charge drops 1-2% per year. Emitters with GHG emissions in excess of the number of units allocated must purchase emissions allowances at auctions or on the carbon market. Emitters with reduced GHG emissions can sell their excess allowances on the carbon market.

In September 2017, Québec signed a cap-and-trade linking agreement with Ontario and California, which came into force on January 1, 2018. This agreement replaces a former agreement between just Québec and California, and it allows any allowances issued by any of the three parties to be accepted by any of the three cap-and-trade programs. The first joint auction of allowances from Ontario, Québec and California was in February 2018.

Québec's comprehensive Energy Policy 2030 ("Policy 2030") seeks to significantly alter Québec's energy profile by 2030 through five demanding targets: enhance energy efficiency by 15%, reduce the amount of petroleum products consumed by 40%, eliminate the use of thermal coal-based energy, increase overall renewable energy output by 25% and increase bioenergy production by 50%. Policy 2030 has a budget of more than \$4 billion over 15 years and will involve the implementation of numerous new regulations.

In December 2016, the Québec Government passed An Act to implement the 2030 Energy Policy and amend various legislative provisions. This legislation includes the Petroleum Resources Act, which, once in force, will replace existing provisions of the Mining Act and establish a licence and authorization system for the exploration, production, and storage of petroleum. It also created Energy Transition Québec; an agency charged with implementing Québec's 2030 target of reducing GHG emissions to 37.5% below 1990 levels.

In March 2017, the Québec Government amended the Environment Quality Act. The amendments, some of which took effect immediately and some of which will come into force over the next two years, will substantially impact the environmental assessment procedure and authorization of industrial projects in Québec.

New Brunswick

In December 2016, New Brunswick released a climate change action plan, transitioning to a Low-Carbon Economy. Pursuant to this plan, the province intends to create a carbon pricing system and introduce caps on GHG emissions that reflect the realities of the New Brunswick economy. Other initiatives under the plan include the phasing out of coal as a source of electricity, investing in new pollution-reduction technology, and increasing progress reporting and oversight by government committees.

In December 2017, New Brunswick introduced the Climate Change Act in its legislature. This legislation, if passed in its current form, will introduce a modified carbon pricing system. New Brunswick will deliver the carbon tax aspect of the pricing system by simply redirecting existing taxes on gasoline and diesel to fund programs that combat climate change. The legislation also allows for New Brunswick to enter an agreement with the federal government whereby the federal backstop standard will be applied to large emitters in New Brunswick. Under this legislation, New Brunswick aims to reduce GHG emissions to 14.8 megatonnes by 2020, 10.7 megatonnes by 2030 and 5 megatonnes by 2050. It is unclear whether or not this carbon pricing system will meet the federal backstop standard.

Even without the Climate Change Act, New Brunswick has already met its 2020 emissions reduction goal, which was a 35% reduction from 1990 levels. It has also met the Paris Agreement's 2030 goal of a 30% reduction from 2005 levels.

ACCOUNTABILITY AND TRANSPARENCY

The federal Extractive Sector Transparency Measures Act (the "ESTMA") imposes mandatory reporting requirements on certain entities engaged in the commercial development of oil, gas or minerals, which includes exploration, extraction and holding permits to explore or extract. All companies subject to ESTMA are required to report payments over \$100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders) and infrastructure improvement payments. These categories are distinct; regardless of the aggregate payment amount, one or more individual categories must reach the \$100,000 threshold for reporting to be required.

Any persons or entities found in violation of the ESTMA (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to \$250,000 for each day that the offence continues. There is a further fine of up to \$250,000 for any person or entity who has structured payments in order to avoid the obligation to report such payments under the ESTMA. Officers or directors who authorized or acquiesced in the commission of an offence can be subject to personal liability, regardless of whether the entity for which they acted has been prosecuted or convicted. The ESTMA contains a due diligence defense whereby no person will be found guilty of an offence under the ESTMA if the person can establish that he or she exercised due diligence to avoid committing the offence. Additionally, there is a five-year limitation period (from the time when the subject matter of the proceeding arises) within which proceedings must be brought for offences under the ESTMA.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The following information is a summary only of certain risk factors relating to the Corporation and should be read in conjunction with the detailed information appearing elsewhere in this AIF. Prospective investors should carefully consider the risk factors set out below and consider all other information contained in this AIF and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

RISKS INHERENT TO THE INDUSTRY

This includes risks normally incident to the natural gas and LNG industries, including the fact that such industries are competitive, and the Corporation competes with numerous other participants to attract and retain customers for its LNG production. There is no assurance that the Corporation will be able to negotiate LNG sales and purchase agreements with new customers on favourable terms, that Uniper Global Commodities S.E. (“Uniper”) will not terminate the LNG Sale and Purchase Agreement in accordance with its terms, that potential customers (including Uniper) will be able to satisfy their obligations under such purchase and sale agreements, of which the Corporation will be substantially dependent upon, and that the Corporation will be able to procure a sufficient long-term supply of natural gas and long-term pipeline transportation capacity for use in the production of LNG.

It also includes risks inherent to the oil and natural gas exploration industry, such as the requirement of additional financing to support its operations. The Corporation will also compete with other companies that have greater financial resources in the context of business opportunities to participate in promising projects. There are natural risks that could cause damage to the environment, accidents or other unforeseen conditions that could result in damage to the properties of the Corporation or to properties owned by third parties which could lead to potential liability toward third parties. There can be no assurance that the development projects and exploration activities that may be implemented in the future will result in reserves or that the Corporation will succeed in drilling productive wells at low exploration costs. Nothing allows planning with certainty the impact that controls and regulations established by the various levels of government will have on the Corporation’s operations, including with respect to the hydraulic fracturing process. Oil and natural gas exploration and development activities in Canada may be subject to opposition from ecologist, environmentalist, aboriginal and even political groups, and some properties may be subject to land claims by First Nations. Access restrictions may affect the Corporation’s ability to procure drilling and related equipment and may delay any exploration and development activities.

WEAKNESS IN THE OIL AND GAS INDUSTRY

Recent market events and conditions including global excess oil and natural gas supply, actions taken by the Organization of the Petroleum Exporting Countries (“OPEC”) and non-OPEC member countries’ decisions on production growth, slowing growth in emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries have caused significant weakness and volatility in commodity prices. North American crude oil price differentials are also expected to continue to be volatile throughout 2019 which will have an impact on crude oil prices for Canadian producers. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at the federal level and, in the case of Alberta, at the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals or other delays to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation’s reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce the Corporation’s cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation’s production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation’s reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation’s indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do it may be on unfavourable and highly dilutive terms.

ADDITIONAL FINANCING

The Corporation will require additional financing to support its operations. A source of future funds available to the Corporation is the issuance of additional shares. The Corporation's operations may also be financed in whole or in part with debt, a partnership agreement or a sale of an interest in an oil or natural gas property. Debt financing may increase the Corporation's debt levels above industry standards. Depending on future development and exploration plans, the Corporation may require additional equity and/or debt financing that may not be available or available on favourable terms. The level of the Corporation's indebtedness that may occur from time to time could impair the Corporation's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Financing by way of a partnership or sale of an interest may reduce the interest held by the Corporation in the properties in respect of which the financing is obtained. There can be no assurance that such financing will be available to the Corporation. Furthermore, even if such financing is successfully secured, there can be no assurance it will be obtained on terms favourable to the Corporation or provide the Corporation with sufficient funds to meet its objectives, which may adversely affect the Corporation's business and financial position. If financing is obtained by issuing additional equity, control of the Corporation may be affected.

SUBSTANTIAL CAPITAL REQUIREMENTS; LIQUIDITY

Pieridae anticipates that it will make substantial capital expenditures for the acquisition, exploration development and production of LNG production, and oil and natural gas reserves in the future. If Pieridae's future revenues or reserves decline or additional financing is not achieved, Pieridae may have limited ability to expend the capital necessary to undertake or complete future drilling and construction programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Pieridae. Moreover, future activities may require Pieridae to alter its capitalization significantly. The inability of Pieridae to access sufficient capital for its operations could have a material adverse effect on Pieridae's financial condition, results of operations or prospects.

CAPITAL MARKETS

Pieridae, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity. The lending capacity of all financial institutions has diminished, and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, non-core property dispositions, borrowings and possible future equity sales, Pieridae's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Pieridae's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, Pieridae's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

SHARE PRICE VOLATILITY

The price of common shares is subject to changes owing to numerous factors beyond the Corporation's control, including reports pertaining to new information, changes in the Corporation's financial position, sales of the Corporation's shares in the market, Corporation announcements or LNG, oil and natural gas prices. There can be no assurance that the market price of the Corporation's shares will be protected from such fluctuations in the future.

IMPACT OF FUTURE FINANCINGS ON MARKET PRICE

In order to finance future operations or acquisition opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares.

COMPETITION

The LNG, oil and natural gas industry is extremely competitive. The Corporation competes with other companies that have ongoing LNG projects. Competition may affect the Corporation's ability to land customers, obtain sufficient supply or access to transportation.

ENVIRONMENTAL ISSUES

The LNG, oil and natural gas operations involve natural risks that could cause damage to the environment or other unforeseen conditions that could result in damage to the properties of the Corporation or to properties owned by third parties which could lead to potential liability toward third parties. The industry is subject to extensive environmental local, provincial and federal legislations providing restrictions and prohibitions on the emissions or release of certain substances produced in various activities within this industry. In addition, the legislation requires that land, wells and facility sites that are abandoned be reclaimed to the satisfaction of government authorities at the end of the licence validity period.

Compliance with environmental legislation can require significant expenditures and failure to comply with these laws and regulations may result in the assessment of fines and penalties, orders to remediate property contamination and the issuance of injunctions that could limit or prohibit our operations, all of which could have a material impact on Pieridae. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Pieridae to incur costs to remedy such discharge. It is likely the trend to stricter environmental legislation will continue. Changes in environmental laws and regulations may be enacted which could impose higher environmental standards which may increase the cost of Pieridae's operations and have a material adverse effect on our business, financial condition, results of operations and cash flows. No assurance can be given that future environmental laws and regulations will not adversely impact Pieridae's ability to develop or operate its properties.

Pieridae believes that it is in material compliance with applicable environmental legislation and is committed to continued compliance. Pieridae believes that it is reasonably likely a trend towards stricter standards in environmental legislation will continue and the Corporation anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws, and such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

See "Industry Conditions – Environmental Regulation" in this AIF.

PRICES, MARKETS AND MARKETING OF CRUDE OIL AND NATURAL GAS

The Corporation's operating results and financial position are partly dependent on the prices obtained for its eventual production. There have been significant fluctuations in LNG, oil and natural gas prices in recent years. These prices are based on international supply and demand, as well as other factors, such as climate, general economic conditions and conditions in other oil and natural gas producing regions, which are beyond the Corporation's control. Any change in LNG, oil and natural gas prices could have material adverse effects on the Corporation's business and financial position.

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Pieridae. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Oil and natural gas prices have varied greatly over the last two years and are expected to remain volatile in the near future in response to a variety of factors beyond the Corporation's control, including, but not limited to: (i) global energy supply, production and policies, including the ability of OPEC to set and maintain production levels in order to influence prices for oil; (ii) political conditions, instability and hostilities; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of crude oil and liquids and the availability and pricing of alternative fuel sources; (v) the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining and fractionation capacity; (viii) the ability, considering regulation and market demand, to export oil and liquefied natural gas and NGLs from North America; (ix) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (x) government regulations. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Pieridae's oil and gas production. Pieridae might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Pieridae's future net production revenue, causing a reduction in its oil and gas acquisition and development activities.

In addition to establishing markets for its oil and natural gas, Pieridae must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Pieridae will be affected by numerous factors beyond its control. Pieridae will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Pieridae. The ability of Pieridae to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Pieridae will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Pieridae has limited direct experience in the marketing of oil and natural gas.

EXPLORATION, DEVELOPMENT AND PRODUCTION RISKS

The future success of the exploration work will depend on Corporation's ability to discover or acquire natural gas reserves that are economically recoverable. The Corporation will find or acquire reserves only if it conducts successful exploration or development activities, concludes joint ventures and/or acquires properties containing proven reserves. There can be no assurance that the development projects and exploration activities that may be implemented in the future will result in reserves or that the Corporation will succeed in drilling productive wells at low exploration costs. If prevailing LNG, oil and natural gas prices were to increase significantly, the Corporation's exploration costs to find or acquire reserves would be expected to increase. Drilling oil wells involves a high degree of risk especially the risk of a dry hole or of a well that is not sufficiently productive to provide a return on the capital expended to drill the well. Thus, the LNG facility supply and the Corporation's financial situation could be impacted by these factors.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves and resources. Without the continual addition of new reserves or resources, the Corporation's existing reserves and resources, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves and resources will depend on both the ability of the Corporation to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, completing, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards or environmental damage could greatly increase the cost of operations and various field operating conditions may adversely affect the production from successful wells. These conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs. See "Insurable Risks" below.

INSURABLE RISKS

Where possible, the Corporation will purchase liability insurance that will insure against risks and provide coverage in accordance with industry standards. The Corporation or the other entities in which the Corporation will invest can suffer damages resulting from incidents such as pollution, fires, blowouts, geological formation damage, oil spills as well as personal injury, against which they may not be insured or they may choose not to be insured in light of high premium costs or other reasons. In addition, indemnities could exceed the policy limits. The costs of repairing such damages or paying such indemnities could cause the ongoing operation of the Corporation's business to become unprofitable and/or impossible.

OPERATIONAL DEPENDENCE

Other companies operate some of the assets in which Pieridae has an interest. As a result, Pieridae will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Pieridae's financial performance. Pieridae's return on assets operated by others will therefore depend upon a number of factors that may be outside of Pieridae's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which Pieridae has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which Pieridae has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, Pieridae may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, Pieridae potentially becoming subject to additional liabilities relating to such assets and Pieridae having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect Pieridae's financial and operational results.

GATHERING AND PROCESSING FACILITIES AND PIPELINE SYSTEMS

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce, and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Mégantic, Québec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of \$1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure that they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

POSSIBLE FAILURE TO REALIZE ANTICIPATED BENEFITS OF ACQUISITIONS

As part of its ongoing strategy, the Corporation may complete acquisitions of assets or other entities in the future. Achieving the benefits of completed and future acquisitions depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and entities requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of any acquisitions.

PROJECT RISKS

Pieridae manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Pieridae's ability to execute projects and market LNG, oil and natural gas will depend upon numerous factors beyond Pieridae's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Pieridae could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

CONFLICTS OF INTEREST

Certain directors of the Corporation serve on the boards of other corporations engaged in natural resource exploration and development operations. Such ties could give rise to conflicts of interest. In making any decisions involving the Corporation, these directors will satisfy their duties and obligations to deal fairly and in good faith with the Corporation and the other entities. In addition, these directors will disclose their interest and refrain from voting on any matter that could give rise to a conflict of interest.

PERMITS, LICENCES AND APPROVALS

The Corporation's business requires permits and licences from government authorities. There can be no assurance that the Corporation will obtain all the permits and licences required to continue exploration operations. In addition, if the Corporation commences commercial operation of property, it must obtain and comply with all the necessary permits and licences. There can be no assurance that the Corporation will be able to obtain or comply with the requirements of such permits and licences.

TITLE TO PROPERTY

While the Corporation has taken reasonable steps to ensure it has good and valid title over its properties, there can be no assurance that title to such properties will not be disputed or challenged. Third parties may have valid claims with respect to the Corporation's properties.

LITIGATION

The Corporation may be held liable for pollution or for other risks for which it cannot be insured or for risks it may choose not to insure in light of high premium costs or other reasons. Payments of amounts in respect thereof may result in the loss of assets of the Corporation.

REGULATORY

The LNG, oil and natural gas industry is subject to controls and regulations established by local, provincial and federal governments with respect to prices, royalties, land tenure, production quotas, imports and exports of LNG, oil, natural gas and environmental protection.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See “Industry Conditions” in this AIF. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation’s costs, either of which may have a material adverse effect on the Corporation’s business, financial condition, results of operations and prospects.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation’s business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the Competition Act (Canada) and the Investment Canada Act (Canada).

ROYALTY REGIMES

The royalty program implemented by each province is a significant factor in the profitability of LNG, oil and natural gas production. Royalties payable on output are determined by government regulation; they are calculated as a percentage of the gross value of output and, typically, the rate of royalties payable depends in part on the prescribed benchmark price, well productivity, geographical location, field discovery date and the type or quality of the resource produced.

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of the Corporation’s projects. An increase in royalties would reduce the Corporation’s earnings and could make future capital investments, or the Corporation’s operations, less economic.

See “Industry Conditions” in this AIF.

HYDRAULIC FRACTURING

The hydraulic fracturing process gives rise to concerns in communities particularly with respect to the drilling fluids used in the fracturing process and their effects on the aquifer, water use in connection with operations, the capability to recycle such water and the seismic effects associated with the process. A number of Canadian provincial governments are currently reviewing aspects of the scientific, regulatory and political framework in which the hydraulic fracturing operations are carried out. At present, most of these governments are taking part in the collection, review and assessment of technical information regarding the hydraulic fracturing process. Pursuant to the new hydrocarbon legislative framework adopted in December 2016 and in force since September 20, 2018, Québec legislation requires that wells and facility sites be built, operated, maintained, abandoned and restored to the satisfaction of the applicable regulatory authorities. The new MERN regulations governing how hydraulic fracturing is carried out under the Petroleum Resources Act. The Ministère du Développement Durable, de l'Environnement et aux Changements Climatiques is also reviewing its main law, the Loi sur la Qualité de l'Environnement and some of its related regulations in conjunction with the MERN. In province of Québec, hydraulic fracturing is now prohibited in the geological formation named Utica shale in the St. Lawrence Lowlands area. Fracturing in any other geological formation is only permitted at a depth greater than 1,000 meters from the surface.

The government of Nova Scotia has restricted hydraulic fracturing since November 2014. The government of New Brunswick has also a ban on hydraulic fracturing.

Although the Corporation has no way of predicting the impact of any potential regulations on its business, the implementation of new laws, regulations, permits or licences regarding the use or disposal of water, or hydraulic fracturing in general, could increase the Corporation's compliance costs and the operating and exploration costs of its properties, the litigation risk and environmental liability of the Corporation and, in turn, adversely impact the future prospects of the Corporation and its financial position.

VARIATIONS IN FOREIGN EXCHANGE RATES

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has seen a material decrease in value against the United States dollar. Any material increases in the value of the Canadian dollar may negatively impacted Pieridae's operating entities production revenues. Any increase in the future Canadian/United States exchange rates could accordingly impact the future value of Pieridae's reserves and resources as determined by independent evaluators.

To the extent that Pieridae engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Pieridae may contract.

HEDGING

From time to time Pieridae may enter into agreements to receive fixed prices on its oil and natural gas production to offset risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Pieridae will not benefit from such increases. Similarly, from time to time Pieridae may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar, however, if the Canadian dollar declines in value compared to the United States dollar, Pieridae will not benefit from its fluctuating exchange rate.

TAX HORIZON

It is expected, based upon current legislation, the projections contained in the Reports and various other assumptions that no cash income taxes are to be paid by Pieridae in the near future. A lower level of capital expenditures than those contained in the Reports or should the assumptions used by Pieridae prove to be inaccurate, Pieridae may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to Pieridae.

SEASONALITY

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of Pieridae's exploration and development activities, which could in turn have a material adverse impact on Pieridae's business, operations and prospects.

THIRD PARTY CREDIT RISK

Pieridae is, or may be exposed to, third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Pieridae, such failures could have a material adverse effect on Pieridae and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Pieridae's ongoing capital program, potentially delaying the program and the results of such program until Pieridae finds a suitable alternative partner.

POLITICAL, GEO-POLITICAL AND SOCIAL RISK

LNG, oil and natural gas exploration and development activities may be subject to opposition from ecologist, environmentalist, aboriginal and non-governmental groups. Demonstrations or acts of civil disobedience could have an impact on the Corporation's business. There can be no assurance that such activities will not target projects in which the Corporation holds an interest. Similarly, there can be no assurance as to any attitude or behaviour of a political party or a political group (whether municipal, provincial or federal) that could have an impact on the Corporation's business.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. The United States has withdrawn from the Trans-Pacific Partnership and the NAFTA agreement has been replaced, the imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation. On September 30, 2018, after a year of negotiation, the United States, Mexico and Canada reached a new trade agreement to be called the United States-Mexico-Canada Agreement ("USMCA"). This agreement has not yet been ratified, and as such, the current NAFTA agreement remains in force. The Corporation is currently assessing the impacts on this agreement and its activities.

In addition to the political disruption in the United States, the citizens of the United Kingdom voted to withdraw from the European Union and the Government of the United Kingdom has started taking steps to implement such withdrawal. Some European countries have also experienced the rise of antiestablishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for third party lessees' operations, reduce their access to skilled labour and as a result, negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

The marketability and price of oil and natural gas that may be acquired or discovered by Pieridae is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Pieridae's net production revenue.

In addition, Pieridae's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Pieridae's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Pieridae. Pieridae does not have insurance to protect against the risk from terrorism.

LAND CLAIMS

Some properties may be subject to land claims by First Nations. There can be no assurance that such land claims will not be made against properties in which the Corporation holds an interest.

GROWTH MANAGEMENT

The Corporation may be subject to growth risks including limitations and pressure on its internal control systems and measures. The Corporation's ability to manage growth effectively will require it to continuously implement and improve its operating and financial systems and expand, train and manage its core workforce. The Corporation's inability to support such growth could have a material adverse impact on its business, operations and prospects.

RELIANCE ON KEY PERSONNEL

Pieridae's future success depends in large measure on certain key personnel. The exploration for, and the development and production of, oil and natural gas with respect to its assets requires experienced executive and management personnel and operational employees and contractors with expertise in a wide range of areas but have a particular expertise in the foothills. There can be no assurance that all of the required employees and contractors with the necessary expertise will be available. Further, the loss of any key personnel may have a material adverse effect on Pieridae's business, financial condition, results of operations and prospects. Pieridae currently does not have any "key man" insurance in place.

Any inability on the part of Pieridae to attract and retain qualified personnel may delay or interrupt the exploration for, and development and production of, oil and natural gas with respect to Pieridae's assets. Sustained delays or interruptions could have a material adverse effect on the financial condition and performance of Pieridae. In addition, rising personnel costs would adversely impact the costs associated with the exploration for, and development and production of, oil and natural gas in respect of Pieridae's assets, which could be significant and material.

COST OF NEW TECHNOLOGIES

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

ALTERNATIVES TO AND CHANGING DEMAND FOR PETROLEUM PRODUCTS

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Pieridae cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Pieridae's business, financial condition, results of operations and cash flows.

INTERNATIONAL PROTOCOLS

Canada has signed international protocols and conventions setting forth certain environment requirements that may adversely affect the Corporation's business. See "Industry Conditions" in this AIF.

CLIMATE CHANGE REGULATIONS

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Current greenhouse gas ("GHG") emissions legislation has not resulted in material compliance costs, however, it is not possible at this time to predict whether proposed legislation or regulations will be adopted, and any such future laws and regulations could result in additional compliance costs or additional operating restrictions.

Adverse impacts to the Corporation's business as a result of comprehensive GHG legislation or regulation applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: (i) increased compliance costs; (ii) permitting delays; (iii) substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and (iv) reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance. See “Industry Conditions – Climate Change Regulation” in this AIF. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to the Corporation.

RESERVE AND RESOURCE ESTIMATES

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and resources and cash flows to be derived therefrom, including many factors beyond Pieridae’s control. The information concerning reserves and resources and associated cash flow set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve and resources recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves and resources attributable to any particular group of properties, classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Pieridae’s actual production, revenues, taxes and development and operating expenditures with respect to its reserves and resources will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and resources and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

In accordance with applicable securities laws, Deloitte has used forecast price and cost estimates in calculating reserve and resources quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the Deloitte Reserves Report, and such variations could be material. The Deloitte Reserves Report is based in part on the assumed success of activities Pieridae intends to undertake in future years. The reserves and resources and estimated cash flows to be derived therefrom contained in the Deloitte Reserves Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Deloitte Reserves Report.

Each of the Deloitte Reserves Report and the Resource Assessment is effective as of a specific effective date and has not been updated and thus does not reflect changes in Pieridae’s reserves or resources since that date.

RESERVE AND RESOURCE REPLACEMENT

Pieridae's future oil and natural gas reserves and resources, production, and cash flows to be derived therefrom are highly dependent on Pieridae successfully acquiring or discovering new reserves and resources. Without the continual addition of new reserves and resources, any existing reserves and resources Pieridae may have at any particular time and the production therefrom will decline over time as such existing reserves and resources are exploited. A future increase in Pieridae's reserves and resources will depend not only on Pieridae's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Pieridae's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

INTERNAL CONTROLS

Effective internal controls are necessary for Pieridae to provide reliable financial reports and to help prevent fraud. Although Pieridae will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Pieridae cannot be certain that such measures will ensure that Pieridae will maintain adequate control over financial processes and reporting.

Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Pieridae's results of operations or cause it to fail to meet its reporting obligations. If Pieridae or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Pieridae financial statements and harm the trading price of the Common Shares.

DIVIDENDS

To date, Pieridae has not paid any dividends on its Common Shares and does not anticipate the payment of any dividends on its Common Shares for the foreseeable future, though it is a possibility that the Corporation may pay dividends in the future if it has started generating sufficient positive cash flow. Any future determination to pay dividends will be at the discretion of the Board and will depend on the financial condition, business environment, operating results, capital requirements, any contractual restrictions on the payment of dividends and any other factors that the Board deems relevant.

DILUTION

Pieridae may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Pieridae which may be dilutive. Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board of Directors may determine. In addition, the Corporation may issue additional Common Shares from time to time pursuant to the Corporation's stock option plan or restricted share unit plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

BREACH OF CONFIDENTIALITY

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

INFORMATION TECHNOLOGY SYSTEMS AND CYBER-SECURITY

The Corporation relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Corporation collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Corporation's employees and third parties. Despite the Corporation's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Corporation's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen.

To date the Corporation has not experienced any material losses relating to cyber-attacks or other information security breaches. However, there can be no assurance that the Corporation will not incur such losses in the future. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Corporation's operations and damage to its reputation, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows. Although the Corporation maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, Pieridae's information technology and infrastructure, including process control systems, the Corporation does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, Pieridae's existing insurance may not provide adequate coverage for losses stemming from a cyber-attack to, or breach of, its information technology and infrastructure.

Although to date the Corporation has not experienced any material losses relating to cyber-attacks or other information security breaches, there can be no assurance that the Corporation will not incur such losses in the future.

REPUTATION RISK

The Corporation relies on its reputation to build and maintain positive relationships with stakeholders, to recruit and retain staff, and to be a credible trusted company. Any actions that Pieridae takes that causes a negative public opinion has the potential to negatively impact the Corporation's reputation which may adversely impact its share price, development plans or its ability to continue operations. Although the Corporation maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, Pieridae's information technology and infrastructure, including process control systems, the Corporation does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, Pieridae's existing insurance may not provide adequate coverage for losses stemming from a cyber-attack to, or breach of, its information technology and infrastructure.

FORWARD-LOOKING STATEMENTS AND INFORMATION MAY PROVE INACCURATE

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties related to forward-looking statements and information are found under the heading "Forward-Looking Statements and Information" in this AIF.

DIVIDENDS AND DIVIDEND POLICY

Pétrolia declared a special dividend on its common shares in a total amount of \$9,011,998.20 (or \$0.083041 per Pétrolia share based on 108,524,683 shares issued and outstanding at the time) to its shareholders of record as of October 20, 2017. This special dividend was paid concurrently to the closing of the Arrangement on October 24, 2017.

The Corporation's dividend policy consists in retaining its earnings in order to finance future growth. As a result, the Corporation has no intention of paying dividends in the foreseeable future. Any future decision to pay dividends will be at the discretion of the board of directors and will depend on the financial position of the Corporation, its results of operations and its capital requirements and such other factors as the board of directors considers relevant.

CAPITAL STRUCTURE

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Corporation consists of an unlimited number of common shares without nominal value of which 84,121,990 were issued and outstanding on the date of this information form. The common shares do not carry any exchange, exercise, conversion, redemption or retraction rights.

The holders of the common shares are entitled to one vote per share at all meetings of shareholders of the Corporation and are entitled to dividends, if and when declared by the directors of the Corporation, and to the distribution of the residual assets of the Corporation in the event of the liquidation, dissolution or winding-up of the Corporation.

MARKET FOR SECURITIES

The common shares of the Corporation are listed on the TSX Venture Exchange (the “TSX-V”) under the symbol “PEA”.

The following table sets forth the reported price range and trading volume of the Common Shares on the TSX-V for the periods indicated.

TABLE 19: Price Range and Trading Volume

	Price Range ⁽¹⁾		Volume ⁽¹⁾
	High (\$/share)	Low (\$/share)	
2017			
August	0.00	0.00	0
September	0.00	0.00	0
October	0.46	0.46	19,794,957
November	5.50	5.50	2,250,322
December	4.47	4.47	2,851,274
2018			
January	5.50	4.15	3,013,356
February	5.95	4.30	565,339
March	5.58	4.51	213,576
April	4.98	4.25	218,652
May	4.95	4.41	232,500
June	4.80	4.21	151,497
July	4.45	3.00	1,500,377
August	4.49	3.13	1,228,573
September	3.87	3.00	408,942
October	4.50	3.30	580,446
November	4.55	3.33	376,500
December	4.31	1.98	1,322,300
2019			
January	2.80	2.35	776,000
February	2.55	1.90	911,200
March	2.07	1.72	835,100
April 1 – 23	2.03	1.75	576,900

- (1) For periods prior to November 2, 2017, the price range and trading volume provided is for Pétrolia common shares traded or quoted on reported by the TSXV. Trading was halted during August 2017 and September 2017 pending completion of the Pétrolia Arrangement. Trading resumed on October 4, 2017 and was halted on October 16, 2017 pending completion of matters in connection with the Pétrolia Arrangement (including a special dividend and share consolidation). On November 2, 2017 trading of Pieridae Shares commenced on an ex-dividend and post-consolidated basis.
- (2) On April 23, 2018, the last trading day prior to the date of this document, the closing price of the Pieridae Shares on the TSXV was \$1.79.

SECURITY ISSUANCES

The following table discloses the securities of the Corporation that have been issued in the 12 months prior to the date of this AIF (all numbers are on a post-consolidation basis).

TABLE 20: Share Issuances

<i>Date of Issuance</i>	<i>Issue Price per Share ⁽¹⁾</i>	<i>Number of Shares Issued ⁽¹⁾</i>
2018		
<i>January 3 ⁽²⁾</i>	\$1.98	2,604
<i>January 8 ⁽²⁾</i>	\$1.98	1,875
<i>January 10 ⁽²⁾</i>	\$1.98	3,906
<i>January 10 ⁽²⁾</i>	\$2.64	2,083
<i>January 24 ⁽²⁾</i>	\$1.98	156
<i>January 29 ⁽²⁾</i>	\$1.98	3,906
<i>January 29 ⁽²⁾</i>	\$2.52	3,125
<i>February 26 ⁽²⁾</i>	\$4.08	18,750
<i>April 5 ⁽²⁾</i>	\$1.98	5,208
<i>April 5 ⁽²⁾</i>	\$2.52	2,083
<i>April 25 ⁽²⁾</i>	\$1.98	2,500
<i>May 8 ⁽³⁾</i>	\$4.90	19,766
<i>June 21 ⁽²⁾</i>	\$1.98	1,302
<i>June 27 ⁽²⁾</i>	\$1.98	1,302
<i>Oct 19 ⁽⁴⁾</i>	\$4.18	21,960
<i>Nov 8 ⁽²⁾</i>	\$2.64	1,042
<i>Dec 7 ⁽²⁾</i>	\$1.98	2,604
<i>Dec 18 ⁽⁵⁾</i>	\$3.40	2,358,824
<i>Dec 20 ⁽⁶⁾</i>	\$2.60	21,582,401
2019		
<i>Jan 2 ⁽⁴⁾</i>	\$2.68	11,281
<i>Feb 27 ⁽⁵⁾</i>	\$2.00	44,115
<i>Feb 28 ⁽⁵⁾</i>	\$2.00	8,956,000
<i>March 6 ⁽⁵⁾</i>	\$2.00	594,000

- (1) Issue Price per Pieridae Share and Number of Pieridae Shares Issued are on a post-consolidation basis, subsequent to the amalgamation of Pieridae and Pétrolia.
- (2) Issuances related to the exercises of stock options.
- (3) Pieridae Shares issued to employees in accordance with Pieridae's RRSP matching policy.
- (4) Pieridae Shares issued to directors in accordance with Director Compensation Policy.
- (5) Pieridae shares issued through a private placement
- (6) Pieridae shares issued on the acquisition of Ikkuma.

Below is a list of the unlisted securities of the Corporation issued during the current fiscal year, including price per security, quantity issued and date of issuance.

TABLE 21: Stock Options

<i>Quantity</i>	<i>Exercise Price (\$)</i>	<i>Issuance Date</i>	<i>Expiry</i>
<i>1,007,400</i>	<i>5.67</i>	<i>January 29, 2018</i>	<i>January 28, 2023</i>
<i>125,000</i>	<i>5.67</i>	<i>June 27, 2018</i>	<i>June 27, 2023</i>
<i>10,000</i>	<i>5.67</i>	<i>September 6, 2018</i>	<i>September 6, 2023</i>

ESCROWED SECURITIES

Below is a description of the total Corporation's securities that are currently held in escrow.

TABLE 22: Escrowed Securities

<i>Designation of Class</i>	<i>Number of Securities Held in Escrow ⁽¹⁾</i>	<i>Percentage of Class</i>
<i>Tier 2 Surplus Escrowed Securities ⁽²⁾</i>		
<i>Common Shares</i>	9,851,806	11.71%
<i>Stock Options</i>	705,840	27.24%
<i>Tier 2 Value Escrowed Securities ⁽³⁾</i>		
<i>Common Shares</i>	1,548,439	1.84%
<i>Stock Options</i>	70,219	2.71%

- (1) Computershare Trust Company of Canada acts as depositary for the securities held in escrow.
- (2) Securities that are currently held in escrow in accordance with the terms of a Tier 2 surplus security escrow agreement (the "TSXV Surplus Escrow Agreement"). The TSXV Surplus Escrow Agreement provides for a release of 5% of the escrowed securities six months after the time of the final Exchange notice accepting completion of the Arrangement (the "**Exchange Notice**"), 10% 12 months after the time of the Exchange Notice, 10% 18 months after the time of the Exchange Notice, 15% 24 months after the time of the Exchange Notice, 15% 30 months after the time of the Exchange Notice, and 40% 36 months after the time of the Exchange Notice. Pursuant to the TSXV Surplus Escrow Agreement, the above-mentioned escrowed securities can only be transferred in accordance with the policies of the Exchange.
- (3) Securities that are currently held in escrow in accordance with the terms of a Tier 2 value security escrow agreement (the "TSXV Tier 2 Value Escrow Agreement"). The TSXV Tier 2 Value Escrow Agreements provides for a release of 15% of the escrowed securities every six months after the issuance of the Exchange Notice. Pursuant to the TSXV Tier 2 Value Escrow Agreement, the escrowed securities can only be transferred in accordance with the policies of the Exchange.

DIRECTORS AND OFFICERS

The following table sets forth the name and municipality of residence of the executive officers of the Corporation, the office they hold with the Corporation and their principal occupation during the last five years.

TABLE 23: Officers of the Corporation

<i>NAME, CITY, PROVINCE AND COUNTRY OF RESIDENCE AND AGE</i>	<i>OFFICE HELD WITH THE CORPORATION</i>	<i>PRINCIPAL OCCUPATION DURING THE LAST 5 YEARS</i>
<i>Alfred Sorensen</i> <i>Calgary, Alberta, Canada</i> <i>Age: 57</i>	President, Chief Executive Officer and Director	President and CEO of Former Pieridae since its founding in 2012. Prior thereto, a principal founder of Galveston LNG Inc. Director of Canadian Spirit Resources Inc. since January 2012.
<i>Mario Racicot</i> <i>(until September 1, 2018)</i> <i>Boucherville, Québec, Canada</i> <i>Age: 50</i>	Chief Financial Officer	Chief Financial Officer of Issuer since May 2016. Prior thereto, Director of Corporate Affairs at Pétrolia since September 2015. Prior thereto held several management positions at the National Bank of Canada and its subsidiary Innocap Investment Management Inc.
<i>Melanie Litoski</i> <i>(from October 1, 2018)</i> <i>Airdrie, Alberta, Canada</i> <i>Age: 48</i>	Chief Financial Officer	Chief Financial Officer for Founders Advantage Capital Corp. from March 2018 to September 30, 2018. Prior thereto Vice President, Controller for Dollar Financial Group from 2014 to March 2018 and Vice President, Finance and Controller for ENMAX Corporation from 2008 to 2014.
<i>Thomas Dawson</i> <i>(until December 20, 2018)</i> <i>Airdrie, Alberta, Canada</i> <i>Age: 56</i>	LNG President	Chief Operating Officer of Former Pieridae since May 2012. Prior thereto, a principle founder of Galveston LNG Inc.

NAME, CITY, PROVINCE AND COUNTRY OF RESIDENCE AND AGE	OFFICE HELD WITH THE CORPORATION	PRINCIPAL OCCUPATION DURING THE LAST 5 YEARS
Martin Bélanger (until December 20, 2018) Calgary, Alberta, Canada Age: 51	Production President	Interim President and Chief Executive Officer of Pétrolia (from September 2016 until October 2017) and Director of Pétrolia from March 26, 2015 until October 24, 2017. Prior thereto, Director of Business Development, Natural Resources Solution Center for IBM Canada Ltd. (September 2015 to August 2016); Director, Oil Pipelines, Commercial Operations Engineering, TransCanada Pipelines Ltd. (September 2013 to May 2015); Director, Production Operations, Laricina Energy Ltd. (May 2011 to September 2013)
Thomas Ciz Vancouver, British Columbia, Canada Age: 59	General Counsel and Corporate Secretary	General Counsel to Former Pieridae since August 1, 2015. Prior thereto, he provided legal services to Former Pieridae and other clients as Associate Counsel at Farris, Vaughan, Wills & Murphy LLP.
Tim De Freitas (since December 21, 2018) Calgary, Alberta Age: 57	Chief Operating Officer	President and Chief Executive Officer of Ikkuma from May 2014 to December 21, 2018. Prior thereto, Vice President, Exploration and Chief Operating Officer of Manito Energy Inc. from inception in 2005 until October 2013.

The following table presents the name and municipality of residence of the directors of the Corporation, their offices held with the Corporation, the date on which they became directors and their principal occupations. Each director will hold office until the next annual meeting of the shareholder of Pieridae or until his successor has been duly elected or appointed, unless he resigns, or his office becomes vacant for any reason.

TABLE 24: Directors of the Corporation

NAME, CITY AND PROVINCE OF RESIDENCE AND AGE	POSITION WITHIN THE CORPORATION	PRINCIPAL OCCUPATION	DIRECTOR SINCE	NUMBER OF SHARES OWNED OR CONTROLLED (1)
Myron A. Tétreault ⁽²⁾ Calgary, Alberta, Canada Age: 51	Chairman	Chairman of Calafate Holdings Ltd. since 1999. Director of Fitzroy Developments Ltd. since 2004 and Northern Vision Development Corp from 2004 to 2018. Currently Lead Director of PHX Energy Services Corp. since 2012 (and director or officer of PHX Energy Services Corp. and its predecessor since 1997), Director of Fitzroyalty Management GP Inc., and Chairman of West Aspen Holdings Ltd. Since 2018.	March 20, 2009	169,522 ⁽⁵⁾ (0.20%)
Alfred Sorensen Calgary, Alberta, Canada Age: 57	President, Chief Executive Officer and Director	President and CEO of Pieridae since its founding in 2012. Prior thereto, a principal founder of Galveston LNG Inc. Currently Director of Canadian Spirit Resources Inc. since January 2012.	October 24, 2017	9,859,235 ⁽⁶⁾ (11.72%)
Andrew Judson ⁽²⁾⁽³⁾ Calgary, Alberta, Canada Age: 50	Director	Director and Senior Advisor of Daytona Power Corp since April 2018, Prior thereto, Managing Partner of Camcor Partners Inc. since 2013. Prior thereto, a Managing Director with FirstEnergy Capital Corp. since September 2007.	October 24, 2017	9,539 ⁽⁷⁾ (0.01%)
Matthew Rees ⁽³⁾⁽⁴⁾ Calgary, Alberta, Canada Age: 46	Director	President and Chief Executive Officer of ORLEN Upstream Canada Ltd. since June 2015. Prior thereto, held positions with Talisman Energy Inc. and Petro-Canada Oil & Gas in the U.K., Columbia and Canada.	October 24, 2017	Nil

NAME, CITY AND PROVINCE OF RESIDENCE AND AGE	POSITION WITHIN THE CORPORATION	PRINCIPAL OCCUPATION	DIRECTOR SINCE	NUMBER OF SHARES OWNED OR CONTROLLED ⁽¹⁾
Charles Boulanger ⁽²⁾⁽⁴⁾ Québec, QC, Canada Age: 60	Director	President and Chief Executing Officer of LeddarTech Inc. and President of Moody Management Inc.	December 11, 2012	51,980 ⁽⁸⁾ (0.06%)
Kjell Pedersen ⁽³⁾⁽⁴⁾ Stavanger, Norway Age: 65	Director	Director of Det Norske Oljeselskap AS from 2015 until 2016. Prior thereto, was Chairman of Aibel AS from April 2013 until March 2015. Prior thereto, CEO of Petoro AS from 2001 until 2013. Mr. Pedersen was also Vice Chairman of the Board of AHLP from June 2014 until July 2016.	June 27, 2018	4,675 ⁽⁹⁾ (0.01%)
Tim De Freitas Calgary, Alberta Age: 57	Director	President and Chief Executive Officer of Ikkuma from May 2014 to December 21, 2018. Prior thereto, Vice President, Exploration and Chief Operating Officer of Manito Energy Inc. from inception in 2005 until October 2013.	December 21, 2018	231,862 (0.28%)

(1) The directors have provided the information concerning the shares that they control. Not including warrants outstanding.

(2) Members of the Audit Committee.

(3) Members of the Compensation and Governance Committee.

(4) Members of the Reserve and Health, Safety and Environment Committee.

(5) Not including 232,291 shares that may be issued to him through options.

(6) Not including 195,000 shares that may be issued to him through options.

(7) Not including 441,150 shares that may be issued to him through options.

(8) Not including 147,915 shares that may be issued to him through options.

(9) Not including 125,000 shares that may be issued to him through options.

The fact that certain directors and officers of the Corporation are associated with other resource companies may lead to conflict of interest situations. If a director or officer is placed in a situation of conflict of interest, he shall abstain from taking part in discussions, decisions, and voting. There are currently no existing or potential material conflicts of interest between the Corporation and any director or officer.

As at the date of this information form, the Corporation's directors and officers beneficially owned, or controlled or directed, directly or indirectly, as a group, a total of 10,326,813 issued and outstanding shares, representing approximately 12.3% of the Corporation's issued and outstanding shares.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of the Corporation, and according to the information that the directors and officers have provided to it, none of them is or has been, within the ten years preceding the date of this Annual Information Form, a director, chief executive officer or chief financial officer of a company that was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of this paragraph, "order" refers to (i) a cease trade order, (ii) an order similar to a cease trade order, or (iii) an order that denied the relevant entity to any exemption under securities legislation.

To the knowledge of the Corporation, none of its directors, executive officers or a shareholder holding a sufficient number of securities of the Corporation to affect materially its control:

- a) is, as at the date of this Annual Information Form, or has been within the 10 years before the date hereof, a director or executive officer of any entity (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, state the fact; or
- b) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder;

To the knowledge of the Corporation, none of its directors or executive officers, or any shareholder holding a sufficient number of securities to affect materially the control of the Corporation, has been subject to:

- a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

LEGAL PROCEEDINGS

Except as disclosed below, the Corporation was not a party to any material legal proceeding, and its assets were not the subject of material legal proceedings, during the year ended December 31, 2018. The Corporation is not aware that any such legal proceeding is threatened.

In March 2013, the Centre Québécois du droit à l'environnement brought a motion in the Superior Court of Québec against Pétrolia for a declaratory judgment regarding drilling activities carried out on Anticosti Island and planned fracturing activities, alleging that such activities required the issuance of a certificate of authorization pursuant to the provisions of the Environment Quality 145 Act (Québec). Based on a draft ministerial order providing a regulatory framework for stratigraphic surveys on Anticosti Island issued by the MERN in June 2014 (and subsequently finalized in July 2014), the parties reached a settlement pertaining to stratigraphic surveys on Anticosti Island which was approved by the Québec Superior Court on June 26, 2014. This motion remains outstanding in all other regards at the date of this AIF.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed in the notes to the financial statements of the Corporation for the year ended December 31, 2018, there is no material interest, direct or indirect, of any director, executive officer, shareholder who beneficially owns, directly or indirectly, more than 10 percent of the Corporation's outstanding common shares, or of any associates or affiliates of such persons, in any transaction within the three most recently completed fiscal years or during the current fiscal year which has materially affected or will materially affect the Corporation.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Ernst & Young LLP, Calgary, Alberta, are the auditors of the Corporation.

The transfer agent and registrar for the common shares of the Corporation is Computershare Trust Corporation of Canada at its office at 530 – 8th Ave SW, Suite 600, Calgary, AB T2P 3S8.

MATERIAL CONTRACTS

As of the date hereof, no material contracts entered into by the Corporation other than in the normal course of its activities are in effect other than the Agreement below:

LNG SALE AND PURCHASE AGREEMENT

The LNG Sale and Purchase Agreement dated May 31, 2013 between Uniper and Goldboro Canada LP, as amended on February 3, 2016; June 2, 2017; and November 1, 2018. This firm contract is subject to early termination rights of Buyer and Seller and certain basic term extension rights of Buyer, the basic term of the LNG Purchase and Sale Agreement commences on May 31, 2013 and terminates on the twentieth anniversary of the Start of Commercial Deliveries. All capitalized terms used below have the meanings given in such agreement.

The LNG Purchase and Sale Agreement contemplates that commencing on the Start of Commercial Deliveries and throughout the balance of the term thereof, Seller will sell to Buyer, and Buyer will purchase from the Seller, LNG having an energy content of 245,000,000 MMBtu per annum (the “Annual Contract Quantity”), subject to adjustment in accordance with Clause 5.2 thereof, (the “Adjusted Annual Contract Quantity”).

Buyer is obliged under the LNG Purchase and Sale Agreement to take and pay, or compensate Seller if not taken, for the applicable Adjusted Annual Contract Quantity, subject to adjustment in accordance with Clause 5.3(a) thereof, (the “Take-or-Pay Quantities”).

Buyer shall pay to Seller a price for each LNG cargo equal to the amount by which the product obtained when the energy content of the LNG cargo, expressed in MMBtu, is multiplied by a reference price, expressed in MMBtu. The reference price is confidential.

Conditions:

- a) the FEED Launch Date must occur not later than April 30th, 2014;
- b) Seller must enter into a sufficient number of binding Gas Supply Agreements with Gas Suppliers as specified in Clause 2.2(a)(i) of the FOB SPA not later than December 31st, 2019;
- c) Seller must enter into a sufficient number of binding Pipeline Capacity Agreements with Pipeline Capacity Suppliers as specified in Clause 2.2(b)(i) the FOB SPA not later than December 31st, 2019;
- d) Seller must obtain the relevant Canada Export Licence not later than December 31st, 2016;
- e) the conditions precedent, if any, in each and every of the Gas Supply Agreements specified in Clause 2.2(a)(i) the FOB SPA must be satisfied in full or waived not later than the FID Date;

- f) the conditions precedent, if any, in each and every of the Pipeline Capacity Agreements specified in Clause 2.2(b)(i) the FOB SPA must be satisfied in full or waived not later than the FID Date;
- g) the completion of Project Finance Secured must occur not later than the FID Date;
- h) the Site Acquisition must occur not later than December 31st, 2016;
- i) the FID Date must occur not later than September 30th, 2019;
- j) the acquisition of Permits Issued must occur not later than June 30th, 2019;
- k) the EPC Launch Date must occur not later than September 30th, 2019; and
- l) the ordering of Major Components must commence not later than September 30th, 2019.

As of the date hereof, conditions a, d, and h have been satisfied. All others remain outstanding.

A copy of the agreement is available on www.sedar.com.

AIMCo DEBT AGREEMENT

The Senior Secured Credit Agreement dated December 20, 2018 between Pieridae and AIMCo has the following key terms and conditions:

- a) Credit Facilities
 - a. Non-Revolving term Credit Facility of CAD \$50,000,000 (Loan) with drawdown made as a single one on the Effective Date (20 December 2018)
 - b. Purpose of the Loan is to repay Ikkuma Outstanding Indebtedness as at Effective Date
- b) Repayment and Prepayment
 - a. Loan repayable on Maturity Date defined as earliest of (i) Sep 30, 2019 or (ii) the day which an Acceleration Notice is delivered (due to an Event of Default as per 9.2(b))
 - b. Voluntary Prepayments made be made in whole or in part with minimum limits of \$1,000,000, without premium or penalty
 - c. Interest is calculated on the basis of a 365-day year at 9.50% per annum, with interest to accrue daily and to be paid in arrears on the maturity date
 - d. The Default Rate of interest includes a premium of 2% over and above the 9.50%
- c) Security
 - a. an Unlimited Guarantee by each Loan party (if there is more than 1) guaranteeing repayment of each other
 - b. A floating charge debenture made for each loan party to which each mortgage, charges and grants a security interest on all present and after acquired property (effectively all the property and assets of all Pieridae entities)
 - c. An account control agreement between the Agent and applicable depository financial institution in respect of the Loan parties bank accounts
 - d. Such other assignments, mortgages, charges, pledges and other security agreements, etc. as may be reasonably requested by Agent
 - e. Borrower shall at its own expense register, file or record the Security in all offices where registration and filing is necessary, including in applicable land titles and land registry offices and grant fixed charges against any and all P&NG Rights and Leases
- d) Covenants
 - a. Timely payment of Indebtedness associated with Loan and maintain existence of each Material Subsidiary

- b. Annual audited Financial Statements and auditors report to be provided to the Lender within 120 days of fiscal year end. Operating Budget and Capital Budget for current fiscal year (as approved by the Board) also to be provided in that timeframe. Quarterly unaudited Financial Statements to be provided within 60 days of quarter end.
- c. Compliance Certificates to be provided with 60 days of Quarter ends and 120 days from Year end certifying amongst other things items such as no Default occurring, Representation and Warranties, and compliance with certain other provisions of the Credit Agreement
- d. Production Reports to be provided with 60 days of Quarter ends and 120 days from Year end. Reports to include volumes produced and sold
- e. Other reports such as Engineering Report (Reserves), any new bank account and notices of Shareholder meetings
- f. A report (in form and substance satisfactory to the Agent) describing the Borrowers capital expenditure program, project development milestones (including related to the UFK Program) and capital raising plan for the then most recently completed month – this report due no later than 10 days after the end of each calendar month
- g. Trade payables in normal course of business and such that those are paid within 90 days of date goods or services delivered
- h. Capital Leases not to exceed CAD \$5M
- i. A revolving operating line of credit issued by a financial institution to one or more of the Loan Parties (Borrower and each Material Subsidiary) in an amount not to exceed CAD \$20M provided that:
- j. Sales of petroleum and natural gas in ordinary course of business, Permitted Encumbrances, Abandonment, Sale or disposition not to exceed in aggregate CAD \$5M in a fiscal year

A copy of the agreement is available on www.sedar.com.

INTEREST OF EXPERTS

Ernst & Young LLP (“EY”) are the external auditors who have prepared the independent auditors’ report to shareholders of the Corporation regarding the financial statements of Pieridae for the year ended December 31, 2018. EY confirmed to the Corporation that they are independent from the Corporation within the meaning of the code of ethics of the Institute of Chartered Accountants of Québec.

Deloitte and Sproule are the petroleum consulting firms who have reviewed the technical report on the properties of the Corporation as at December 31, 2018, and which is referred to under “Properties of the Corporation”. At the time of preparation of such reports, neither Deloitte nor Sproule owned any common shares of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation is available on SEDAR at www.sedar.com.

Additional information in respect of the remuneration of the directors and officers, the principal holders of securities of the Corporation, share options, and insiders having interests in material transactions, if any, is available in the Management Information Circular dated November 14, 2018, relating to the Special Meeting of Shareholders of the Ikkuma which was held on December 17, 2018 for Shareholders of Ikkuma.

Additional financial information is available in the Corporation’s consolidated financial statements and Management’s Discussion & Analysis of Results for the year ended December 31, 2018.

APPENDIX A: DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

BACKGROUND INFORMATION

- 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.
- 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.
- Unrecoverable is that portion of Discovered or Undiscovered Petroleum Initially-In-Place 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.
- The resources have been reported in accordance with Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”) guidelines that recommend disclosure of low, best and high estimates to reflect the range of uncertainty associated with the resource estimates, as follows:
 - Low Estimate: This is considered to be a conservative estimate of the quantity of oil actually in place. It is likely that the actual in-place quantity will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantity actually in place will equal or exceed the low estimate.
 - Best Estimate: This is considered to be the best estimate of the quantity of oil actually in place. It is the mean volume of the estimates.
 - High Estimate: This is considered to be an optimistic estimate of the quantity of oil actually in place. It is unlikely that the actual in-place quantity will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantity actually in place will equal or exceed the high estimate.

HALDIMAND PROJECT

**TABLE 1: Low, Best, and High Estimates of Pieridae Energy's P&NG Contingent Resources in the Haldimand York River Formation
(As of December 31, 2018)**

Area		Gross Land Holding Discovered Petroleum Initially-In-Place (DPIIP)			Gross Land Holding Contingent Resources ⁽⁴⁾				Net Company Interest Contingent Resources ⁽⁴⁾			
		Unrisked			Unrisked			Risked ⁽⁶⁾	Unrisked			Risked ⁽⁶⁾
		Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾
Haldimand	Light & Medium Oil (Mbbl)	13,856	87,968	199,126	574	5,373	12,536	161.2	574	5,373	12,536	161.2
	Conventional Natural Gas (MMcf) ⁽⁹⁾				4,950	41,887	94,952	1,256.6	4,950	41,887	94,952	1,256.6
	Total (Mboe)				1,399	12,354	28,361	370.6	1,399	12,354	28,361	370.6

(1) Low represents the P90 volume estimate.

(2) Best represents the mean volume estimate.

(3) High represents the P10 volume estimate.

(4) Contingent Resources are sub-classified as Contingent - Development Unclassified (Risked = Best*3%).

(5) It is mathematically invalid to determine a risked success-case distribution for any probability level other than the mean itself by multiplying an unrisked success case by the chance of commerciality.

(6) Risked: A 37 percent chance of development risk (63 percent chance of not proceeding with development.) (If the Petroleum Resources Act adopted on September 20, 2018 was considered, an 8 percent chance of development risk would have been used.). Risked figures are based on an aggregate of the following risks factors: environment drilling, regulatory approval, economic factors, corporate commitment, timing of production and development, market access, technology under development, legal factors, political factors and social licence.

(7) Oil resources are presented in thousands of barrels, at stock tank conditions.

(8) Gas resources are presented in millions of cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit.

(9) Solution gas.

On September 20, 2017, the Québec Government published a draft hydrocarbon regulation, titled “GAZETTE OFFICIELLE DU QUÉBEC, September 20, 2017, Vol. 149, No. 38”. This draft regulation indicated that the use of hydraulic fracturing would be permitted and presented the process in which an operator could apply for a permit, as well as the conditions surrounding the fracture stimulation operations. Risk factors related to Regulatory Approval and Political Factors estimated based on the indication that fracture stimulations would be permitted in the future. The aggregate Chance of Commerciality applied for Contingent Resources was estimated to be 3% in this report.

In June 2018 the government of Québec announced an amendment to the proposed regulations. The amended regulation imposed a complete prohibition of hydraulic fracturing in shale gas, as well as a ban on fracturing within the first 1,000 meters of depth, as well as a complete prohibition of exploration and production within 1,000 meters from areas of urbanization and 1,000 meters from bodies of water. In September 2018, these revisions came into force.

The Company has indicated that this project is partially within 1,000 meters of areas of urbanization or bodies of water. The York River Formation evaluated in this report is not a shale formation, but it is shallower than 1,000 meters. This development would not be allowed to proceed using horizontal multi-stage hydraulic fracturing technology, as was evaluated in this report.

BOURQUE PROJECT

**TABLE 2: Low, Best, and High Estimates of Pieridae Energy's P&NG Contingent Resources in the Bourque Forillon Formation
(As of December 31, 2018)**

Areas		Gross Land Holding Contingent Resources ⁽⁵⁾				Net Company Interest Contingent Resources ⁽⁵⁾			
		Unrisked			Risked ⁽⁸⁾	Unrisked			Risked ⁽⁸⁾
		Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾
Bourque North	Light & Medium Oil (Mbbbl)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Conventional Natural Gas (MMcf) ⁽¹²⁾	0	0	0	0	0	0	0	0
	NGL (Mbbbl)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total (Mboe)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bourque South	Light & Medium Oil (Mbbbl)	390.0	2,241.0	2,536.2	672.3	199.0	1,143.6	2,536.2	343.1
	Conventional Natural Gas (MMcf) ⁽¹²⁾	5,460	17,753	34,856	5,326	2,786	9,060	17,787	2,718
	NGL (Mbbbl)	158.3	514.8	1,010.8	154.5	80.8	262.7	515.8	78.8
	Total (Mboe)	1,458.4	5,714.7	9,356.4	1,714.4	744.2	2,916.2	6,016.5	874.9
Bourque-2 Area	Light & Medium Oil (Mbbbl)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Conventional Natural Gas (MMcf) ⁽¹²⁾	0	0	0	0	0	0	0	0
	NGL (Mbbbl)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total (Mboe)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total⁽⁴⁾	Light & Medium Oil (Mbbbl)		2,241.0		672.3		1,143.6		343.1
	Conventional Natural Gas (MMcf) ⁽¹²⁾		17,753		5,326		9,059.6		2,717.9
	NGL (Mbbbl)		514.8		154.5		262.7		78.8
	Total (Mboe)		5,714.7		1,714.4		2,916.2		874.9

(1) Low represents the P90 volume estimate.

(2) Best represents the mean volume estimate.

(3) High represents the P10 volume estimate.

(4) Arithmetic summation is valid for the mean estimate only.

(5) Contingent Resources are sub-classified as Contingent - Development Unclassified (Risked = Best*30%).

(6) Prospective Resources are sub-classified as Prospective - Prospect (Risked=Best*26%).

- (7) It is mathematically invalid to determine a risked success-case distribution for any probability level other than the mean itself by multiplying an unrisked success case by the chance of commerciality.
- (8) Risked: A 30 percent chance of development risk (70 percent chance of not proceeding with development) Risked figures are based on an aggregate of the following risks factors: environment drilling, regulatory approval, economic factors, corporate commitment, timing of production and development, market access, technology under development, legal factors, political factors, social licence.
- (9) Oil resources are presented in thousands of barrels, at stock tank conditions.
- (10) Gas resources are presented in millions of cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit.
- (11) Natural gas liquids resources are presented in thousands of barrels, at base conditions of 60 degrees Fahrenheit and equilibrium pressure.
- (12) Solution gas

**TABLE 3: Low, Best, and High Estimates of Pieridae Energy's P&NG Prospective Resources in the Bourque Forillon by Sub-Area Formation
(As of December 31, 2018)**

Areas		Gross Land Holding Prospective Resources ⁽⁶⁾				Net Company Interest Prospective Resources ⁽⁶⁾			
		Unrisked			Risked ⁽⁹⁾	Unrisked			Risked ⁽⁹⁾
		Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Best ⁽²⁾
Bourque North	Light & Medium Oil (Mbbl)	479.0	1,978.0	8,157.0	514.3	244.4	1,009.4	4,162.5	262.4
	Conventional Natural Gas (MMcf) (13)	6,527	19,710	59,826	5,125	3,331	10,058	30,529	2,615
	NGL (Mbbl)	189.3	571.6	1,734.9	148.6	96.6	291.7	885.3	75.8
	Total (Mboe)	1,756.1	5,834.6	19,862.9	1,517.0	896.1	2,977.4	10,136.0	774.1
Bourque South	Light & Medium Oil (Mbbl)	3,277.0	12,404.0	47,418.0	3,225.0	1,672.3	6,329.8	24,197.4	1,645.7
	Conventional Natural Gas (MMcf) (13)	45,106	124,410	342,327	32,347	23,018	63,486	174,689	16,506
	NGL (Mbbl)	1,308.1	3,607.9	9,927.5	938.0	667.5	1,841.1	5,066.0	478.7
	Total (Mboe)	12,102.8	36,746.8	114,399.9	9,554.2	6,176.0	18,751.9	58,378.3	4,875.5
Bourque-2 Area	Light & Medium Oil (Mbbl)	422.0	1,680.0	6,559.0	436.8	215.3	857.3	3,347.1	222.9
	Conventional Natural Gas (MMcf) (13)	59	167	481	44	30	85	245	22
	NGL (Mbbl)	1.7	4.9	13.9	1.3	0.9	2.5	7.1	0.6
	Total (Mboe)	433.4	1,712.8	6,653.0	445.3	221.2	874.0	3,395.0	227.2
Grand Total⁽⁴⁾	Light & Medium Oil (Mbbl)		16,062.0		4,176.1		8,196.4		2,131.1
	Conventional Natural Gas (MMcf)⁽¹³⁾		144,287		37,515		73,629.7		19,143.7
	NGL (Mbbl)		4,184.3		1,087.9		2,135.3		555.2
	Total (Mboe)		44,294.2		11,516.5		22,603.3		5,876.9

- (1) Low represents the P90 volume estimate.
- (2) Best represents the mean volume estimate.
- (3) High represents the P10 volume estimate.
- (4) Arithmetic summation is valid for the mean estimate only.

- (5) Contingent Resources are sub-classified as Contingent - Development Unclassified (Risked = Best*30%).
- (6) Prospective Resources are sub-classified as Prospective - Prospect (Risked=Best*26%).
- (7) It is mathematically invalid to determine a risked success-case distribution for any probability level other than the mean itself by multiplying an unrisked success case by the chance of commerciality.
- (8) Risked: A 30 percent chance of development risk (70 percent chance of not proceeding with development) Risked figures are based on an aggregate of the following risks factors: environment drilling, regulatory approval, economic factors, corporate commitment, timing of production and development, market access, technology under development, legal factors, political factors, social licence.
- (9) Risked: A 26 percent chance of commerciality risk (74 percent chance of not proceeding with development). This is the product of a 30 percent chance of development risk and a 90 percent chance of discovery risk. Risked figures are based on an aggregate of the following risks factors: environment drilling, regulatory approval, economic factors, corporate commitment, timing of production and development, market access, technology under development, legal factors, political factors, social licence and chance of discovery.
- (10) Oil resources are presented in thousands of barrels, at stock tank conditions.
- (11) Gas resources are presented in millions of cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit.
- (12) Natural gas liquids resources are presented in thousands of barrels, at base conditions of 60 degrees Fahrenheit and equilibrium pressure.
- (13) Solution gas.

On September 20, 2017, the Québec Government published a draft hydrocarbon regulation, titled “GAZETTE OFFICIELLE DU QUÉBEC, September 20, 2017, Vol. 149, No. 38”. This draft regulation indicated that the use of hydraulic fracturing would be permitted and presented the process in which an operator could apply for a permit, as well as the conditions surrounding the fracture stimulation operations. Risk factors related to Regulatory Approval and Political Factors estimated based on the indication that fracture stimulations would be permitted in the future. The aggregate Chance of Commerciality applied for Contingent Resources was estimated to be 30%, and the aggregate Chance of Commerciality applied for Prospective Resources was estimated to be 26% in this report.

In June 2018 the government of Québec announced an amendment to the proposed regulations. The amended regulation imposed a complete prohibition of hydraulic fracturing in shale gas, as well as a ban on fracturing within the first 1,000 meters of depth, as well as a complete prohibition of exploration and production within 1,000 meters from areas of urbanization and 1,000 meters from bodies of water. In September 2018, these revisions came into force.

The Company has indicated that this project is not within 1,000 meters of areas of urbanization or bodies of water. The Forillon Formation evaluated in this report is not a shale formation, and it is deeper than 1,000 meters. Hydraulic fracturing is not banned for this formation. It is Sproule’s opinion that the June 2018 announcement does not require a change in the risk factors related to Regulatory Approval and Political Factors and the Chance of Commerciality of this project remains at 30% for the Contingent Resources and 26% for the Prospective Resources.

TABLE 4: Low, Best, and High Estimates of Pieridae Energy's Petroleum Initially-In-Place in the Bourque Forillon Formation (As of December 31, 2018)

Areas	Total Petroleum Initially-In-Place (TPIIP)			Discovered Petroleum Initially-In-Place (DPIIP)			Undiscovered Petroleum Initially-In-Place (UPIIP)		
	Pool Volumes (100% Working Interest) (Mbbl)								
	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾
Bourque North	26,000	99,000	199,000	0	0	0	26,000	99,000	199,000
BourqueSouth	206,000	647,000	1,246,000	23,000	62,000	115,000	183,000	585,000	1,131,000
Bourque-2 Area	24,000	81,000	161,000	0	0	0	24,000	81,000	161,000
Grand Total ⁽⁴⁾		827,000			62,000			765,000	

Areas	Total Petroleum Initially-In-Place (TPIIP)			Discovered Petroleum Initially-In-Place (DPIIP)			Undiscovered Petroleum Initially-In-Place (UPIIP)		
	Company Working Interest Volumes (51.03% WI) (Mbbl)								
	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾	Low ⁽¹⁾	Best ⁽²⁾	High ⁽³⁾
Bourque North	13,268	50,520	101,550	0	0	0	13,268	50,520	101,550
Bourque South	105,122	330,164	635,834	11,737	31,639	58,685	93,385	298,526	577,149
Bourque-2 Area	12,247	41,334	82,158	0	0	0	12,247	41,334	82,158
Grand Total ⁽⁴⁾		422,018			31,639			390,380	

(1) Low represents the P90 volume estimate.

(2) Best represents the mean volume estimate.

(3) High represents the P10 volume estimate.

(4) Arithmetic summation is valid for the mean estimate only.

DISCLOSURE OF RESOURCES DATA

The statement of resources data and other oil and gas information set forth below is a summary of information contained in the “Technical Review of P&NG Holdings of Pieridae Energy Limited in Québec and New Brunswick (as of December 31, 2018)” (the “Report”) dated January 1, 2019. The Report was prepared in part for the purpose of evaluating the Corporation’s P&NG resources according to the COGE Handbook resources definitions and standards and consistent with NI 51-101. In accordance with these standards, and by reference in NI 51-101, tables were presented for forecast prices and costs, which summarize the resources and net present values, as of December 31, 2018.

As of December 31, 2018, no oil or natural gas reserves have been assigned to any of the Québec properties in which Pieridae has an interest. As Pieridae has no development pending contingent resources, it has not reported related future net revenue.

RESOURCES

Table 5 sets forth the Corporation’s contingent resources data in the Haldimand area of Québec, as at December 31, 2018. The contingent resources data are risked estimates of volume as at December 31, 2018.

TABLE 5

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Riskd Volume Light & Medium Oil (Mbbl)	Riskd Volume Conventional Natural Gas (MMcf)	Riskd Volume Total (Mboe)
Development Unclarified Best Estimate Contingent Resources	Sproule	December 31, 2018	Canada	161.2	1,256.6	370.6

Tables 6 and 7 present the Corporation’s contingent and prospective resources data in the Bourque area of Québec, as at December 31, 2018. The contingent and prospective resources data are risked estimates of volume as at December 31, 2018.

TABLE 6

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Risked Volume Light & Medium Oil (Mbbl)	Risked Volume Conventional Natural Gas (MMcf)	Risked Volume NGL (Mbbl)	Risked Volume Total (Mboe)
Development Unclassified Best Estimate Contingent Resources	Sproule	December 31, 2018	Canada	343	2,718	79	875

TABLE 7

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Risked Volume Light & Medium Oil (Mbbl)	Risked Volume Conventional Natural Gas (MMcf)	Risked Volume NGL (Mbbl)	Risked Volume Total (Mboe)
Best Estimate Prospective Resources - Prospect	Sproule	December 31, 2018	Canada	2,131	19,144	555	5,877

RESOURCE DEFINITIONS

This discussion has been excerpted from Sections 5.2 and 5.3 of the COGE Handbook, Second Edition, September 1, 2007.

The following definitions relate to the subdivisions in the SPE-PRMS resources classification framework and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS, with direct excerpts shown in *italics*.

Total Petroleum Initially-In-Place (“PIIP”) 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 according to the level of certainty associated with the estimates and may be subclassified based on development and production status.

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 subclassified based on project maturity and/or characterized by their economic status.

Unrecoverable is that portion of Discovered or 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 subclassified based on project maturity.

RESOURCE CATEGORIES

Due to the high uncertainty in estimating resources, evaluations of these assets require some type of probabilistic methodology. Expected value concepts and decision tree analyses are routine; however, in high-risk, high-reward projects, Monte Carlo simulation can be used. In any event, three success cases plus a failure case should be included in the evaluation of the resources (see Section 9 of the COGE Handbook for details on these methods).

CLASSIFICATION OF RESOURCES

When evaluating resources, in particular, contingent and prospective resources, the following mutually exclusive categories are recommended:

- **Low Estimate:** This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P⁹⁰ confidence level.
- **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of central tendency of the uncertainty distribution (most likely/mode, P⁵⁰/median, or arithmetic average/mean).
- **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P¹⁰ confidence level.

Corporation Gross Contingent Resources are the Corporation's working interest share of the Contingent Resources, before deduction of any royalties.

Corporation Net Contingent Resources are the gross contingent resources of the properties in which the Corporation has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

Fair Market Value is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

Resources and Contingent Resources do not constitute, and should not be confused with, reserves. Actual reserves and resources will vary from the reserve and resource estimates, and those variations could be material.

As of December 31, 2018, Pieridae has no Prospective or Contingent Resources in Western Canada.

As of December 31, 2018, no oil or natural gas reserves have been assigned to any of the Québec properties in which Pieridae has an interest.

**APPENDIX B: NI 51-101 FORM F2 REPORT ON RESERVES DATA BY INDEPENDENT
QUALIFIED RESERVES EVALUATOR OR AUDITOR (DELOITTE)**



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

To the Board of Directors of Ikkuma Resources Corp., a wholly owned subsidiary of Pieridae Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 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.
5. The following table shows the net present value of 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 for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent qualified reserves evaluator or auditor	Effective date of 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	Ikkuma Resources Corp. Reserve estimation and economic evaluation December 31, 2018	Canada	-	396,088.1	-	396,088.1

6. 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.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. 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: "Andrew Botterill"

Andrew Botterill, P. Eng.
Partner

Execution date: March 11, 2019

**APPENDIX C: FORM 51-101F2 REPORT ON CONTINGENT RESOURCES DATA AND
PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES
EVALUATOR (SPOULE)**

Form 51-101F2: Bourque Area of Quebec

**Report on Contingent and Prospective Resources Data
by Independent Qualified Reserves Evaluator or Auditor**

To the Board of Directors of Pieridae Energy Limited (the "Company"):

1. We have evaluated the Company's contingent and prospective resources data in the Bourque area of Quebec, as at December 31, 2018. The contingent and prospective resources data are risked estimates of volume as at December 31, 2018.
2. The contingent and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent and prospective resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following tables set forth the risk volume of contingent and prospective resources attributed to best estimate contingent and prospective resources, included in the Company's statement prepared in accordance with Form 51-101F1, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Risk Volume Light & Medium Oil (Mbbl)	Risk Volume Conventional Natural Gas (MMcf)	Risk Volume NGL (Mbbl)	Risk Volume Total (Mboe)
Development Unclassified Best Estimate Contingent Resources	Sproule	December 31, 2018	Canada	343	2,718	79	875

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Risk Volume Light & Medium Oil (Mbbl)	Risk Volume Conventional Natural Gas (MMcf)	Risk Volume NGL (Mbbl)	Risk Volume Total (Mboe)
Best Estimate Prospective Resources - Prospect	Sproule	December 31, 2018	Canada	2,131	19,144	555	5,877

6. In our opinion, the contingent and prospective resources 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 contingent resources data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the Contingent and Prospective Resources of Pieridae Energy Limited in the Bourque Area of Quebec, Canada (As of December 31, 2018) – Summary Report".
8. Because the contingent and prospective resources data are based on judgments regarding future events, actual results will vary and the variations may be material.
9. No oil or natural gas reserves have been assigned in the Bourque Area of Quebec property.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
January 3, 2019

Original Signed by Matthew J. Tymchuk, P.Eng.

Matthew J. Tymchuk, P.Eng.
Manager, Engineering

Original Signed by Suryanarayana Karri, P.Geoph.

Suryanarayana Karri, P.Geoph.
Petrophysical Specialist

Original Signed by Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
VP, Geoscience

Original Signed by Nora T. Stewart, P.Eng.

Nora T. Stewart, P.Eng.
Senior VP, Reserves Certification and Director

Form 51-101F2: Halimand Area of Quebec

Report on Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Pieridae Energy Limited (the “Company”):

1. We have evaluated the Company’s contingent resources data in the Haldimand area of Quebec, as at December 31, 2018. The contingent resources data are risked estimates of volume as at December 31, 2018.
2. The contingent resources data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “COGE Handbook”), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the risk volume contingent resources attributed to best estimate contingent resources, included in the Company's statement prepared in accordance with Form 51-101F1, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Resources Other than Reserves (Country)	Risk Volume Light & Medium Oil (Mbbl)	Risk Volume Conventional Natural Gas (MMcf)	Risk Volume Total (Mboe)
Development Not Viable Best Estimate Contingent Resources	Sproule	December 31, 2018	Canada	161.2	1,257	370.6

6. In our opinion, the contingent resources 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 contingent resources data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the Contingent Resources of Pieridae Energy Limited in the Haldimand Area of Quebec, Canada (As of December 31, 2018) – Summary Report".
8. Because the contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.
9. No oil or natural gas reserves have been assigned in the Haldimand Area of Quebec property.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
January 3, 2019

Original Signed by Matthew J. Tymchuk, P.Eng.

Matthew J. Tymchuk, P.Eng.
Manager, Engineering

Original Signed by Suryanarayana Karri, P.Geoph.

Suryanarayana Karri, P.Geoph.
Petrophysical Specialist

Original Signed by Alexey Romanov, Ph.D., P.Geo.

Alexey Romanov, Ph.D., P.Geo.
Senior Geoscientist

Original Signed by Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
VP, Geoscience

Original Signed by Nora T. Stewart, P.Eng.

Nora T. Stewart, P.Eng.
Senior VP, Reserves Certification and Director

APPENDIX D: FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Pieridae Energy Limited (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with the securities regulatory requirements. This information includes resources data, which are estimates of contingent and prospective resources as at December 31, 2018.

An independent qualified reserve evaluator has evaluated and reviewed the Corporation's resources data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has:

- a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- c) reviewed the resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

- a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- b) the filing of the Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- c) the content and filing of this report.

Because the contingent and prospective resources data are based on judgments regarding future events, actual results will vary, and the variations may be material.

April 24, 2019

(signed) Alfred Sorensen
Alfred Sorensen,
Chief Executive Officer

(signed) Matthew Rees
Matthew Rees,
Director

(signed) Tim De Freitas
Tim De Freitas,
Chief Operating Officer

(signed) Andrew Judson
Andrew Judson,
Director

APPENDIX E: DEFINITIONS USED FOR RESERVE AND RESOURCE CATEGORIES

The following definitions form the basis of the classification of reserves and values presented in the Deloitte Reserves Report and the Resources Report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM incorporated in the COGE Handbook and specified by NI 51-101.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

RESERVE CLASSIFICATIONS

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

Proved Reserves

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

Probable Reserves

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

Possible 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. Possible reserves have not been considered in this AIF.

RESERVE CATEGORIES

Other criteria that must also be met for categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserve categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

Developed Reserves

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 (e.g., 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

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

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

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

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 contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

- a) There is a 90% probability that at least the estimated proved reserves will be recovered.
- b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
- c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

RESOURCES

Resources encompass 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. Resources are classified as follows:

- a) Total PIIP 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. "Total resources" is equivalent to "total PIIP".
- b) Discovered PIIP 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 PIIP includes production, reserves and contingent resources; the remainder is unrecoverable.
- c) 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.
- d) Undiscovered PIIP 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 PIIP is referred to as prospective resources; the remainder is unrecoverable.
- e) 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
- f) 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.
- g) Production is the cumulative quantity of petroleum that has been recovered at a given date.

UNCERTAINTY RANGES FOR RESOURCES

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

- a) A "low estimate" 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% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- b) A "best estimate" 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% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- c) A "high estimate" 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% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

OTHER DEFINITIONS

Gross Reserves or Resources

The Corporation's working interest share of the remaining reserves or resources, before deduction of any royalties.

Net Reserves or Resources

The gross remaining reserves or resources of the properties in which the Corporation has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

Net Production Revenue

Income derived from the sale of net reserves of oil, pipeline gas, and gas by-products, less all capital and operating costs.

Fair Market Value

The price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

Barrels of Oil Equivalent (BOE) Reserves

The sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.

Oil (or Crude Oil)

A mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

Gas (or Natural Gas)

A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

Non-Associated Gas

An accumulation of natural gas in a reservoir where there is no crude oil.

Associated Gas

The gas cap overlying a crude oil accumulation in a reservoir.

Natural Gas By-Products

Those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

Products Types

A sub-classification of the principle product types of petroleum, crude oil, gas and by products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the production types they require to be used for reporting purposes in their jurisdiction. The Canadian Securities Association (CSA) defines the Product Types for reporting purposes in NI 51-101, with the following Product Types referenced in this AIF.

Crude Oil

Light Crude Oil

Crude oil with a relative density greater than 31.1 degrees API gravity.

Medium Crude Oil

Crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

Natural Gas

Conventional Natural Gas

Natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

By Products

Natural Gas Liquids

Those hydrocarbon components that can be recovered from natural gas as a liquid including, but not, limited to, ethane, propane, butanes, pentanes plus and condensates.

RESOURCE CATEGORIES

Due to the high uncertainty in estimating resources, evaluations of these assets require some type of probabilistic methodology. Expected value concepts and decision tree analyses are routine; however, in high-risk, high-reward projects, Monte Carlo simulation can be used. In any event, three success cases plus a failure case should be included in the evaluation of the resources (see Section 9 of the COGE Handbook for details on these methods).