



## NEWS RELEASE

February 8, 2017

### **ARC RESOURCES LTD. REPLACES 260 PER CENT OF PRODUCED RESERVES THROUGH DEVELOPMENT ACTIVITIES IN 2016**

**Calgary, February 8, 2017 (ARX - TSX)** ARC Resources Ltd. ("ARC") is pleased to report its 2016 year-end reserves and resources information.

*"ARC delivered another year of outstanding reserves results, replacing 260 per cent of 2016 produced reserves through development activities at low finding and development costs of \$4.02 per boe for proved plus probable reserves. Exceptional well performance from our Montney assets resulted in positive technical revisions and material reserves growth in 2016. These results highlight the increasing depth of ARC's low-cost Montney asset base and the strong technical expertise of our team,"* said Myron Stadnyk, President and CEO. *"An updated Independent Resources Evaluation for our northeast British Columbia and Pouce Coupe assets also saw significant growth, with now greater than 100 Tcf of total shale gas initially-in-place and more than 10 billion barrels of total tight oil initially-in-place identified across ARC's Montney lands. Coupled with our strong balance sheet and excellent operating and capital efficiencies, ARC is in an enviable position as we continue to develop these world-class assets and gain greater confidence in initiating larger-scale development projects across our Montney portfolio."*

#### **HIGHLIGHTS**

- Replaced 260 per cent of total 2016 production <sup>(1)</sup>, adding 113.5 MMboe of proved plus probable ("2P") reserves through development activities. Over the last nine years, ARC has replaced an average of 200 per cent or greater produced reserves through development activities.
- Positive technical revisions of 33 MMboe (2P) were realized, predominantly in Sunrise and Dawson, reflecting the strong well performance of ARC's Montney assets.
- Proved developed producing ("PDP") reserves decreased from 222 MMboe to 212 MMboe. The net decrease in PDP reserves was driven by dispositions, notably ARC's non-core Saskatchewan asset sale which accounted for 21 MMboe of the total 24 MMboe divested at year-end 2016.
- Total proved reserves increased by eight per cent from 393 MMboe to 426 MMboe, and 2P reserves increased by seven per cent from 687 MMboe to 737 MMboe.
- Replaced 289 per cent of 2016 natural gas production, adding 0.5 Tcf of 2P natural gas reserves. Replaced 725 per cent of natural gas liquids ("NGLs") production, adding 21.0 MMbbl of 2P NGLs reserves. Replaced 76 per cent of 2016 oil production, adding 8.7 MMbbl of 2P oil reserves. Replaced 97 per cent of 2016 oil produced, disregarding production from ARC's Saskatchewan assets which were sold in the fourth quarter of 2016.
- Material reserves growth was realized in ARC's Montney assets, particularly in Sunrise, Dawson, Parkland/Tower, Attachie, and Ante Creek.
- Finding and Development ("F&D") costs <sup>(1)</sup> were \$4.02 per boe for 2P reserves, \$5.15 per boe for proved reserves and \$10.46 per boe for proved producing reserves, excluding Future Development Capital ("FDC"). Significant NE BC Montney reserve additions combined with capital reductions contributed to the 42 per cent reduction in 2P F&D costs relative to 2015.
- FDC increased by \$25 million compared to year-end 2015, to total \$2.8 billion at year-end 2016. Adds due to additional development activities in the Montney were offset by the FDC reduction associated with dispositions that occurred in 2016.
- ARC updated an Independent Resources Evaluation (the "Resources Evaluation" or "Independent Resources Evaluation") for its lands in the NE BC Montney region, including lands at Pouce Coupe in Alberta. The updated evaluation realized an increase in the identified resource base on ARC's NE BC Montney lands. The shale gas Total Petroleum Initially-in-Place ("TPIIP") increased 13 per cent from 90.0 Tcf in 2015 to 101.5 Tcf in 2016 and tight oil TPIIP increased nine per cent from 9.7 billion barrels of oil in 2015 to 10.5 billion barrels in 2016 <sup>(2)</sup>.

- Best Estimate Risked Development Pending resources increased to 529 MMboe at year-end 2016 from 471 MMboe at year-end 2015, while before-tax present value, discounted at 10 per cent, increased to \$1.8 billion from \$1.2 billion year-over-year.
- (1) "Reserve replacement" and "Finding and Development costs" or "F&D costs" do not have standardized meanings. See "*Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information*" contained in this news release.
  - (2) The year-end 2016 Resources Evaluation complies with current Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") guidelines. The Resources Evaluation volumes provided are the "Best Estimate" case. Year-end 2016 and 2015 TPIIP estimates utilize a one per cent porosity cut-off for shale gas based upon "Best Estimate" case. Estimates for year-end 2016 were determined using a one per cent porosity cut-off, and for year-end 2015 using a three per cent porosity cut-off for tight oil based upon "Best Estimate" case.

## 2016 INDEPENDENT RESERVES EVALUATION

GLJ Petroleum Consultants ("GLJ") conducted an Independent Reserves Evaluation (the "Reserves Evaluation" or "Independent Reserves Evaluation") effective December 31, 2016, which was prepared in accordance with definitions, standards and procedures contained in the COGE Handbook and National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The reserves evaluation was based on GLJ forecast pricing and foreign exchange rates at January 1, 2017, as outlined in Table 1 below.

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without the inclusion of any royalty interest) unless otherwise noted. In addition to the detailed information disclosed in this news release, more detailed information will be included in ARC's Annual Information Form ("AIF") for the year ended December 31, 2016, which will be available on ARC's website at [www.arcresources.com](http://www.arcresources.com) and filed on SEDAR at [www.sedar.com](http://www.sedar.com) on or before March 31, 2017.

Based on this Independent Reserves Evaluation, ARC's reserves profile as at December 31, 2016 is summarized below:

- Seven per cent increase in 2016 2P reserves to 737 MMboe compared to 687 MMboe of 2P reserves at year-end 2015. 2P reserves are comprised of 3.2 Tcf of natural gas, 124 MMbbl of oil and 72 MMbbl of NGLs at year-end 2016. The NGLs are comprised of 54 per cent condensate (39 MMbbl), 40 per cent propane (29 MMbbl), and six per cent butane (4 MMbbl).
- 113.5 MMboe of 2P reserve additions from development activities (including revisions), before net acquisitions and dispositions of negative 20.5 MMboe and 2016 production of 43.4 MMboe. Technical revisions of 32.5 MMboe more than offset the removal of 3.4 MMboe due to economic factor revisions resulting from the decrease in commodity price forecasts since year-end 2015.
- Replaced 260 per cent of total 2016 production, adding 113.5 MMboe of 2P reserves through development activities, with 2016 production of 43.4 MMboe.
- Total proved reserves account for 58 per cent of 2P reserves.
- PDP reserves represent 50 per cent of total proved reserves and 29 per cent of 2P reserves.
- Oil and NGLs comprise 27 per cent of 2P reserves and natural gas comprises 73 per cent of 2P reserves, using the commonly accepted boe conversion ratio of six Mcf to one barrel.
- Additions from development activities resulted in increased reserves, hand-in-hand with increased FDC for these development activities, resulting in one-year 2P F&D costs, including FDC, of \$6.10 per boe for 2016, and \$6.48 per boe for the three-year average. Proved F&D costs, including FDC, were \$11.71 per boe for 2016 and \$10.11 per boe for the three-year average.
- Strong 2P reserve life index ("RLI") <sup>(1)</sup> of 16.4 years at year-end 2016, up from 15.9 years at year-end 2015. The increase in RLI is attributed to strong reserves growth in 2016. For details on ARC's 2017 production guidance, see the February 8, 2017 news release entitled, "*ARC Resources Ltd. Announces Fourth Quarter and Year-end 2016 Results as It Increases Capital Investment in Multi-year, Large-scale Development Projects at Dawson, Parkland/Tower, and Sunrise*".
- Recycle ratio <sup>(1)</sup> of 3.4 times and 2.9 times for the current year and the three-year average, respectively, for 2P reserves, based on current and three-year average F&D costs, excluding FDC, which are based on current and three-year average operating netbacks <sup>(2)</sup> of \$13.59 per boe and \$20.93 per boe, respectively.

- Abandonment and reclamation costs decreased from \$527 million (undiscounted) at year-end 2015 to \$462 million (undiscounted) at year-end 2016. These costs have been included in the 2P reserves, which account for the abandonment and reclamation of all wells to which reserves have been attributed.
- Acquisition of working interests in Pembina Cardium in 2016 and disposition of ARC's non-core Saskatchewan assets at the end of the fourth quarter of 2016 resulted in a net reduction in PDP reserves of approximately 7 MMboe.

(1) "Reserve life index" or "RLI" and "recycle ratio" do not have standardized meanings. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.

(2) "Operating netback" is a non-GAAP measure and does not have a standardized meaning under IFRS. See "Non-GAAP Measures" contained within ARC's Management's Discussion and Analysis ("MD&A").

**Table 1**

GLJ Price Forecast at January 1	WTI Crude Oil (US\$/bbl)		Edmonton Light Oil (Cdn\$/bbl)		AECO Natural Gas (Cdn\$/MMBtu)		Foreign Exchange (US\$/Cdn\$)	
	2017	2016	2017	2016	2017	2016	2017	2016
2017	<b>55.00</b>	52.00	<b>69.33</b>	64.00	<b>3.46</b>	3.27	<b>0.750</b>	0.750
2018	<b>59.00</b>	58.00	<b>72.26</b>	68.39	<b>3.10</b>	3.45	<b>0.775</b>	0.775
2019	<b>64.00</b>	64.00	<b>75.00</b>	73.75	<b>3.27</b>	3.63	<b>0.800</b>	0.800
2020	<b>67.00</b>	70.00	<b>76.36</b>	78.79	<b>3.49</b>	3.81	<b>0.825</b>	0.825
2021	<b>71.00</b>	75.00	<b>78.82</b>	82.35	<b>3.67</b>	3.90	<b>0.850</b>	0.850
2022	<b>74.00</b>	80.00	<b>82.35</b>	88.24	<b>3.86</b>	4.10	<b>0.850</b>	0.850
2023	<b>77.00</b>	85.00	<b>85.88</b>	94.12	<b>4.05</b>	4.30	<b>0.850</b>	0.850
2024	<b>80.00</b>	87.88	<b>89.41</b>	96.48	<b>4.16</b>	4.50	<b>0.850</b>	0.850
2025	<b>83.00</b>	89.63	<b>92.94</b>	98.41	<b>4.24</b>	4.60	<b>0.850</b>	0.850
2026 <sup>(1)</sup>	<b>86.05</b>		<b>95.61</b>		<b>4.32</b>		<b>0.850</b>	0.850
Escalate thereafter at	<b>+2% / year</b>	+2% / year	<b>+2% / year</b>	+2% / year	<b>+2% / year</b>	+2% / year	<b>0.850</b>	0.850

(1) Escalated at two per cent per year starting in 2026 in the January 1, 2017 GLJ price forecast with the exception of foreign exchange, which remains flat.

**Table 2**

Reserves Summary <sup>(1)</sup>	Crude and Tight Oil <sup>(2)</sup>	NGLs	Natural Gas <sup>(3)</sup>	2016 Oil Equivalent	2015 Oil Equivalent
Company Gross	(Mbbbl)	(Mbbbl)	(MMcf)	(Mboe)	(Mboe)
Proved Producing	<b>66,956</b>	<b>13,040</b>	<b>794,069</b>	<b>212,341</b>	221,509
Proved Developed Non-Producing	<b>1,581</b>	<b>916</b>	<b>50,599</b>	<b>10,930</b>	12,062
Proved Undeveloped	<b>20,247</b>	<b>24,108</b>	<b>949,808</b>	<b>202,656</b>	159,755
<b>Total Proved</b>	<b>88,783</b>	<b>38,064</b>	<b>1,794,476</b>	<b>425,927</b>	393,327
<b>Proved plus Probable</b>	<b>123,996 <sup>(4)</sup></b>	<b>71,504</b>	<b>3,247,395 <sup>(5)</sup></b>	<b>736,733</b>	686,851

(1) Amounts may not add due to rounding.

(2) Crude and Tight Oil includes product types of light and medium crude oil, tight oil and heavy crude oil.

(3) Natural Gas includes product types of shale gas and conventional natural gas.

(4) Proved plus Probable Crude and Tight Oil closing balance by percentage weighting of product type: approximately 62 per cent light and medium crude oil, 36 per cent tight oil and two per cent heavy crude oil.

(5) Proved plus Probable Natural Gas closing balance by percentage weighting of product type: approximately 97 per cent shale gas and three per cent conventional natural gas.

**Table 3**

<b>Reserves Reconciliation <sup>(1)</sup></b>	<b>Crude and Tight Oil <sup>(2)</sup></b>	<b>NGLs</b>	<b>Natural Gas <sup>(3)</sup></b>	<b>Oil Equivalent</b>
<b>Company Gross</b>	<b>(Mbbbl)</b>	<b>(Mbbbl)</b>	<b>(MMcf)</b>	<b>(Mboe)</b>
<b>Proved Producing</b>				
Opening Balance, January 1, 2016	82,163	12,712	759,803	221,509
Exploration Discoveries	—	—	—	—
Extensions and Improved Recovery <sup>(4)</sup>	4,225	1,498	95,103	21,573
Technical Revisions	2,216	1,790	123,802	24,640
Acquisitions	11,561	526	12,683	14,200
Dispositions	(21,371)	(412)	(12,140)	(23,807)
Economic Factors	(446)	(194)	(11,923)	(2,627)
Production	(11,392)	(2,879)	(173,259)	(43,148)
<b>Ending Balance, December 31, 2016</b>	<b>66,956</b>	<b>13,040</b>	<b>794,069</b>	<b>212,341</b>
<b>Total Proved</b>				
Opening Balance, January 1, 2016	98,860	29,052	1,592,492	393,327
Exploration Discoveries	—	—	—	—
Extensions and Improved Recovery <sup>(4)</sup>	11,836	4,819	196,415	49,391
Technical Revisions	2,794	7,176	192,353	42,030
Acquisitions	12,468	573	13,863	15,352
Dispositions	(25,044)	(469)	(15,885)	(28,161)
Economic Factors	(740)	(208)	(11,503)	(2,865)
Production	(11,392)	(2,879)	(173,259)	(43,148)
<b>Ending Balance, December 31, 2016</b>	<b>88,783</b>	<b>38,064</b>	<b>1,794,476</b>	<b>425,927</b>
<b>Proved plus Probable</b>				
Opening Balance, January 1, 2016	146,483	53,343	2,922,145	686,851
Exploration Discoveries	—	—	—	—
Extensions and Improved Recovery <sup>(4)</sup>	10,195	11,462	376,732	84,445
Technical Revisions	(897)	9,652	142,685	32,535
Acquisitions	16,004	740	17,901	19,727
Dispositions	(35,812)	(652)	(22,687)	(40,246)
Economic Factors	(584)	(160)	(16,123)	(3,431)
Production	(11,392)	(2,879)	(173,259)	(43,148)
<b>Ending Balance, December 31, 2016</b>	<b>123,996 <sup>(5)</sup></b>	<b>71,504</b>	<b>3,247,395 <sup>(6)</sup></b>	<b>736,733</b>

(1) Amounts may not add due to rounding.

(2) Crude and Tight Oil includes product types of light and medium crude oil, tight oil and heavy crude oil.

(3) Natural Gas includes product types of shale gas and conventional natural gas.

(4) Reserves additions for infill drilling, improved recovery, and extensions are combined and reported as "Extensions and Improved Recovery".

(5) Proved plus Probable Crude and Tight Oil closing balance by percentage weighting of product type: approximately 62 per cent light and medium crude oil, 36 per cent tight oil and two per cent heavy crude oil.

(6) Proved plus Probable Natural Gas closing balance by percentage weighting of product type: approximately 97 per cent shale gas and three per cent conventional natural gas.

### Reserve Life Index

ARC's 2P RLI was 16.4 years at year-end 2016, while the proved RLI was 9.6 years based upon dividing the appropriate GLJ reserves category by ARC's 2017 production guidance midpoint of 121,000 boe per day, which is contingent upon the execution of a \$750 million capital program for 2017. The 2P RLI has been maintained at greater than 15 years since year-end 2010, as a result of successful delineation and reserves growth of the Montney in northeast British Columbia. ARC's annual average production has increased from 83,416 boe per day in 2011 to 118,671 boe per day in 2016. Table 4 summarizes ARC's historical RLI.

**Table 4**

<b>Reserve Life Index</b>	<b>2016<sup>(1)</sup></b>	2015	2014	2013	2012
Total Proved	<b>9.6</b>	9.1	8.5	9.1	10.5
Proved plus Probable	<b>16.4</b>	15.9	15.0	15.5	17.5

(1) Based on production guidance midpoint of 121,000 boe per day for 2017.

### Net Present Value Summary

ARC's oil, natural gas and NGLs reserves were evaluated using GLJ's commodity price forecasts at January 1, 2017. The net present value ("NPV") is prior to provision for interest, debt service charges, and general and administrative expenses. It should not be assumed that the NPV of future net revenue estimated by GLJ represents the fair market value of the reserves. The NPV of ARC's reserves increased relative to year-end 2015 due to material reserve adds in 2016. NPVs on both a before- and after-tax basis are presented in Table 5.

**Table 5**

<b>NPV of Future Net Revenue<sup>(1)(2)</sup></b> (\$ millions)	<b>Undiscounted</b>	<b>Discounted at 5%</b>	<b>Discounted at 10%</b>	<b>Discounted at 15%</b>	<b>Discounted at 20%</b>
<b>Before-tax</b>					
Proved Producing	4,626	3,296	2,585	2,148	1,852
Proved Developed Non-Producing	154	116	91	75	63
Proved Undeveloped	2,729	1,593	982	615	380
Total Proved	7,509	5,005	3,659	2,839	2,295
Probable	6,531	3,451	2,174	1,519	1,134
Proved plus Probable	14,040	8,457	5,832	4,358	3,429
<b>After-tax<sup>(3)(4)</sup></b>					
Proved Producing	3,827	2,786	2,218	1,863	1,619
Proved Developed Non-Producing	112	84	66	54	45
Proved Undeveloped	2,002	1,123	647	362	179
Total Proved	5,941	3,993	2,931	2,278	1,843
Probable	4,778	2,511	1,565	1,079	795
Proved plus Probable	10,719	6,504	4,496	3,358	2,638

(1) Amounts may not add due to rounding.

(2) Based on NI 51-101 net interest reserves and GLJ price forecasts and costs at January 1, 2017.

(3) Based on ARC's estimated tax pools at year-end 2016.

(4) The after-tax NPV of the future net revenue attributed to ARC's oil and natural gas properties reflects the tax burden on the properties on a standalone basis. It does not consider the business entity tax-level situation or tax planning, nor does it provide an estimate of the value at the level of the business entity, which may be significantly different. ARC's audited consolidated financial statements and notes and MD&A should be consulted for information at the business entity level.

At a 10 per cent discount factor, and on a before-tax basis, the future net revenue attributed to the proved producing reserves constitutes 71 per cent of the future net revenue attributed to the total proved reserves (NPV10 before-tax), while the future net revenue attributed to the total proved reserves accounts for 63 per cent of the future net revenue attributed to the 2P reserves (NPV10 before-tax).

### Future Development Capital

FDC reflects the independent evaluator's best estimate of what it will cost to bring the proved and probable developed and undeveloped reserves on production. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities, and changes in capital cost estimates based on improvements in well design and performance, as well as changes in service costs. FDC increased by \$25 million compared to year-end 2015, to total \$2.8 billion at year-end 2016. Adds due to additional development activities in the Montney were offset by the FDC reduction associated with dispositions that occurred in 2016.

Table 6 outlines GLJ estimated FDC required to bring total proved and total 2P reserves on production.

**Table 6**

<b>Future Development Capital</b> <sup>(1)(2)</sup> (\$ millions)	<b>Total Proved</b>	<b>Total Proved plus Probable</b>
2017	542	662
2018	530	639
2019	404	524
2020	151	279
2021	94	211
Remainder	187	441
<b>Total FDC, Undiscounted</b>	<b>1,908</b>	<b>2,755</b>
<b>Total FDC, Discounted at 10%</b>	<b>1,553</b>	<b>2,169</b>

(1) Amounts may not add due to rounding.

(2) FDC as per GLJ Independent Reserves Evaluation as of December 31, 2016 and based on GLJ forecast pricing at January 1, 2017.

ARC's 2017 capital budget is \$750 million, 13 per cent higher than the proved plus probable FDC forecast for 2017. The total proved plus probable FDC, undiscounted, is less than four times ARC's 2017 capital budget. For details on ARC's 2017 capital budget, see the February 8, 2017 news release entitled, "*ARC Resources Ltd. Announces Fourth Quarter and Year-end 2016 Results as It Increases Capital Investment in Multi-year, Large-scale Development Projects at Dawson, Parkland/Tower, and Sunrise*".

#### **Finding, Development and Acquisition Costs**

ARC's 2016 F&D costs were \$4.02 per boe and \$5.15 per boe for 2P and proved reserves, respectively, excluding FDC (\$6.10 per boe and \$11.71 per boe, respectively, for 2P and proved reserves, including FDC). ARC's three-year average F&D costs were \$7.19 per boe for 2P reserves and \$9.56 per boe for proved reserves, excluding FDC. The low F&D costs are attributed to the high quality of ARC's portfolio of assets, strong results from ARC's development program, and meaningful reserves growth, notably at Sunrise, Dawson and Tower. ARC's 2016 F&D costs include approximately \$3 million of spending on Crown lands, with no significant associated reserves or production associated with these acquisitions in the current year.

Including net acquisitions, ARC's 2016 Finding, Development and Acquisition ("FD&A") <sup>(1)</sup> costs were \$(0.82) per boe for 2P reserves and \$(1.01) per boe for proved reserves, excluding FDC (\$(0.55) per boe and \$4.53 per boe, respectively, for 2P and proved reserves, including FDC). Due to the disposition of ARC's non-core Saskatchewan assets, the annual capital including net dispositions was negative in 2016, which resulted in negative one-year 2P F&D costs, including FDC. Given the negative annual capital, one-year F&D costs, including FDC, are not meaningful. The three-year average FD&A costs were \$6.31 per boe for 2P reserves and \$8.13 per boe for proved reserves, excluding FDC. ARC's low FD&A costs reflect ARC's focus on high-quality assets, cost management, and allocation of resources and capital investment to high rate of return projects. ARC's 2016 FD&A costs include approximately \$3 million of spending on Crown lands, with no significant associated reserves or production. Additionally, ARC's FD&A costs incorporate the net disposition of properties with associated reserves and production for approximately \$532 million in 2016.

(1) "Finding, development and acquisition costs" or "FD&A costs" does not have a standardized meaning. See "*Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information*" contained in this news release.

Table 7 highlights ARC's reserves, F&D costs, FD&A costs and the associated recycle ratios for the past three years.

**Table 7**

<b>Reserves (Company Gross), Capital Expenditures and Operating Netbacks</b> <sup>(1)(2)</sup>	<b>2016</b>	<b>2015</b>	<b>2014</b>
<b>Reserves (Mboe)</b>			
Proved Producing	<b>212,341</b>	221,509	209,509
Total Proved	<b>425,927</b>	393,327	382,063
Proved plus Probable	<b>736,733</b>	686,851	672,748
<b>Capital Expenditures (\$ millions)</b>			
Exploration and Development	<b>456.1</b>	548.3	1,007.8
Net Property Acquisitions (Dispositions)	<b>(532.5)</b>	(74.4)	34.2
Total Capital Expenditures	<b>(76.4)</b>	473.9	1,042.0
<b>Operating Netbacks (\$/boe)</b>			
Operating Netback	<b>13.59</b>	16.69	33.01
Operating Netback – Three-Year Average	<b>20.93</b>	25.91	28.86

(1) Amounts may not add due to rounding.

(2) "Operating netback" is a non-GAAP measure and does not have a standardized meaning under IFRS. See "Non-GAAP Measures" contained within ARC's MD&A.

**Table 7a**

<b>Finding and Development Costs, excluding FDC</b> <sup>(1)(2)(3)</sup>	<b>2016</b>	<b>2015</b>	<b>2014</b>
<b>Company Gross</b>			
<b>Proved Producing</b>			
Reserve Additions (MMboe)	<b>43.6</b>	66.0	48.0
F&D Costs (\$/boe)	<b>10.46</b>	8.31	20.99
F&D Recycle Ratio	<b>1.3</b>	2.0	1.6
F&D Costs – Three-Year Average (\$/boe)	<b>12.77</b>	15.05	20.49
F&D Recycle Ratio – Three-Year Average	<b>1.6</b>	1.7	1.4
<b>Total Proved</b>			
Reserve Additions (MMboe)	<b>88.6</b>	66.9	55.0
F&D Costs (\$/boe)	<b>5.15</b>	8.20	18.32
F&D Recycle Ratio	<b>2.6</b>	2.0	1.8
F&D Costs – Three-Year Average (\$/boe)	<b>9.56</b>	14.13	17.32
F&D Recycle Ratio – Three-Year Average	<b>2.2</b>	1.8	1.7
<b>Proved plus Probable</b>			
Reserve Additions (MMboe)	<b>113.5</b>	78.7	87.5
F&D Costs (\$/boe)	<b>4.02</b>	6.97	11.51
F&D Recycle Ratio	<b>3.4</b>	2.4	2.9
F&D Costs – Three-Year Average (\$/boe)	<b>7.19</b>	10.36	11.15
F&D Recycle Ratio – Three-Year Average	<b>2.9</b>	2.5	2.6

(1) F&D costs take into account reserves revisions during the year on a per boe basis.

(2) The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.

(3) "Finding and development recycle ratio" or "F&D recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.

**Table 7b**

<b>Finding and Development Costs, including FDC <sup>(1)(2)</sup></b>			
<b>Company Gross</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>
<b>Proved Producing</b>			
Change in FDC (\$ millions)	<b>19.0</b>	(53.5)	32.9
Reserve Additions (MMboe)	<b>43.6</b>	66.0	48.0
F&D Costs (\$/boe)	<b>10.90</b>	7.49	21.68
F&D Recycle Ratio	<b>1.2</b>	2.2	1.5
F&D Costs – Three-Year Average (\$/boe)	<b>12.76</b>	15.19	21.09
F&D Recycle Ratio – Three-Year Average	<b>1.6</b>	1.7	1.4
<b>Total Proved</b>			
Change in FDC (\$ millions)	<b>581.3</b>	(535.6)	69.6
Reserve Additions (MMboe)	<b>88.6</b>	66.9	55.0
F&D Costs (\$/boe)	<b>11.71</b>	0.19	19.58
F&D Recycle Ratio	<b>1.2</b>	87.8	1.7
F&D Costs – Three-Year Average (\$/boe)	<b>10.11</b>	11.61	18.81
F&D Recycle Ratio – Three-Year Average	<b>2.1</b>	2.2	1.5
<b>Proved plus Probable</b>			
Change in FDC (\$ millions)	<b>236.5</b>	(770.3)	333.5
Reserve Additions (MMboe)	<b>113.5</b>	78.7	87.5
F&D Costs (\$/boe)	<b>6.10</b>	(2.82)	15.32
F&D Recycle Ratio	<b>2.2</b>	(5.9)	2.2
F&D Costs – Three-Year Average (\$/boe)	<b>6.48</b>	8.11	13.34
F&D Recycle Ratio – Three-Year Average	<b>3.2</b>	3.2	2.2

(1) F&D costs take into account reserves revisions during the year on a per boe basis.

(2) The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.

**Table 7c**

<b>Finding, Development and Acquisition Costs, excluding FDC</b> <sup>(1)(2)(3)</sup>			
<b>Company Gross</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>
<b>Proved Producing</b>			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>34.0</b>	53.4	41.7
FD&A Costs (\$/boe)	<b>(2.25)</b>	8.88	24.97
FD&A Recycle Ratio	<b>(6.0)</b>	1.9	1.3
FD&A Costs – Three-Year Average (\$/boe)	<b>11.15</b>	17.02	22.77
FD&A Recycle Ratio – Three-Year Average	<b>1.9</b>	1.5	1.3
<b>Total Proved</b>			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>75.7</b>	52.6	48.8
FD&A Costs (\$/boe)	<b>(1.01)</b>	9.00	21.37
FD&A Recycle Ratio	<b>(13.5)</b>	1.9	1.5
FD&A Costs – Three-Year Average (\$/boe)	<b>8.13</b>	15.98	18.99
FD&A Recycle Ratio – Three-Year Average	<b>2.6</b>	1.6	1.5
<b>Proved plus Probable</b>			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>93.0</b>	55.5	79.6
FD&A Costs (\$/boe)	<b>(0.82)</b>	8.54	13.10
FD&A Recycle Ratio	<b>(16.6)</b>	2.0	2.5
FD&A Costs – Three-Year Average (\$/boe)	<b>6.31</b>	11.88	11.94
FD&A Recycle Ratio – Three-Year Average	<b>3.3</b>	2.2	2.4

(1) FD&A costs take into account reserves revisions during the year on a per boe basis.

(2) The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.

(3) "Finding, development and acquisition recycle ratio" or "FD&A recycle ratio" does not have a standardized meaning. See "*Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information*" contained in this news release.

**Table 7d**

<b>Finding, Development and Acquisition Costs, including FDC <sup>(1)(2)</sup></b>			
<b>Company Gross</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>
<b>Proved Producing</b>			
Change in FDC (\$ millions)	<b>(95.9)</b>	(63.4)	31.0
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>34.0</b>	53.4	41.7
FD&A Costs (\$/boe)	<b>(5.07)</b>	7.69	25.71
FD&A Recycle Ratio	<b>(2.7)</b>	2.2	1.3
FD&A Costs – Three-Year Average (\$/boe)	<b>10.16</b>	17.09	23.41
FD&A Recycle Ratio – Three-Year Average	<b>2.1</b>	1.5	1.2
<b>Total Proved</b>			
Change in FDC (\$ millions)	<b>419.7</b>	(589.5)	69.2
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>75.7</b>	52.6	48.8
FDA& Costs (\$/boe)	<b>4.53</b>	(2.20)	22.79
FD&A Recycle Ratio	<b>3.0</b>	(7.6)	1.4
FD&A Costs – Three-Year Average (\$/boe)	<b>7.56</b>	12.69	20.74
FD&A Recycle Ratio – Three-Year Average	<b>2.8</b>	2.0	1.4
<b>Proved plus Probable</b>			
Change in FDC (\$ millions)	<b>25.0</b>	(906.2)	333.2
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	<b>93.0</b>	55.5	79.6
FD&A Costs (\$/boe)	<b>(0.55)</b>	(7.80)	17.29
FD&A Recycle Ratio	<b>(24.7)</b>	(2.1)	1.9
FD&A Costs – Three-Year Average (\$/boe)	<b>3.91</b>	8.58	14.44
FD&A Recycle Ratio – Three-Year Average	<b>5.4</b>	3.0	2.0

(1) FD&A costs take into account reserves revisions during the year on a per boe basis.

(2) The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.

## **NE BC MONTNEY RESOURCES EVALUATION**

*The following discussion in "NE BC Montney Resources Evaluation" is subject to a number of cautionary statements, assumptions and risks as set forth therein. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" at the end of this news release for additional cautionary language, explanations and discussion, and see "Forward-looking Information and Statements" for a statement of principal assumptions and risks that may apply. See also "Definitions of Oil and Gas Resources and Reserves" in this news release. The discussion includes reference to TPIIP, Discovered Petroleum Initially-in-Place ("DPIIP"), Undiscovered Petroleum Initially-in-Place ("UPIIP") and Economic Contingent Resource ("ECR") as per the GLJ Resources Evaluation as at December 31, 2016, prepared in accordance with the COGE Handbook. Unless otherwise indicated in this news release, all references to ECR and Prospective volumes are Best Estimate ECR and Best Estimate Prospective volumes, respectively.*

The Montney formation in northeast British Columbia and Alberta has been identified as a world-class unconventional natural gas resource play with the potential for significant volumes of recoverable resources. The area includes dry gas, liquids-rich gas and tight oil development opportunities. It is one of the largest and lowest-cost natural gas resource plays in North America. ARC has a significant presence in northeast British Columbia and across the provincial border at Pouce Coupe, with a land position of 744 net sections, located primarily in the most prospective areas of the play.

GLJ was commissioned in 2016 and in 2015 to conduct independent resource evaluations for ARC's lands in the NE BC Montney region, including Dawson, Parkland/Tower, Sunrise/Sunset, Sundown, Septimus, Attachie, Red Creek and Blueberry in northeast British Columbia, and Pouce Coupe just across the provincial border in Alberta (the "Evaluated Areas"). The Independent Resources Evaluation was effective December 31, 2016 based on GLJ forecast pricing at January 1, 2017. The GLJ Independent Resources Evaluation conducted in respect of 2015 was effective December 31, 2015 based on GLJ forecast pricing at January 1, 2016 (the "2015 Resources Evaluation"). All references in the following discussion to TPIIP, DPIIP, UPIIP and ECR are in reference to the Evaluated Areas included in the 2016 Independent Resources Evaluation and 2015 Independent Resources Evaluation. The results of the 2016 and 2015 resources evaluations are summarized in the discussion and tables that follow.

The evaluation reaffirmed that ARC's NE BC Montney assets provide a significant long-term growth opportunity with considerable resources, extending well beyond existing booked reserves and even the current estimates of the ECR. ARC's NE BC Montney assets provide optionality for future growth through commodity price cycles given the diversity of ARC's Montney landholdings with exposure to liquids-rich natural gas, crude oil and dry natural gas. ARC believes that the concentrated nature of the assets will result in additional upside based on expected capital efficiencies.

ARC's 2016 capital development program was primarily focused on Montney development, which was inclusive of crude oil, liquids-rich gas and dry gas opportunities. In northeast British Columbia, ARC's capital development program consisted of drilling 51 gross operated wells (50.5 net wells), comprised of 22 tight oil wells and one liquids-rich well at Tower, 16 wells at Dawson that were a combination of dry gas and liquids-rich wells, three dry gas wells at Sunrise, and nine liquids-rich wells elsewhere in NE BC (three in Attachie, three in Parkland, one in Blueberry, and two in Pouce Coupe).

TPiIP for the shale gas-bearing lands in the Evaluated Areas increased 13 per cent to 101.5 Tcf relative to 2015. DPIIP for the shale gas-bearing lands increased slightly by one per cent for the Evaluated Areas to 41.8 Tcf. Growth in shale gas TPiIP is driven by a revised geological interpretation due to improved understanding of the Montney.

Shale gas ECR was evaluated on an unrisks and risks basis in 2016 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risks development pending shale gas ECR totaled 2.6 Tcf and risks development unclarified shale gas ECR totaled 3.6 Tcf. The risks prospective shale gas ECR totaled 7.0 Tcf.

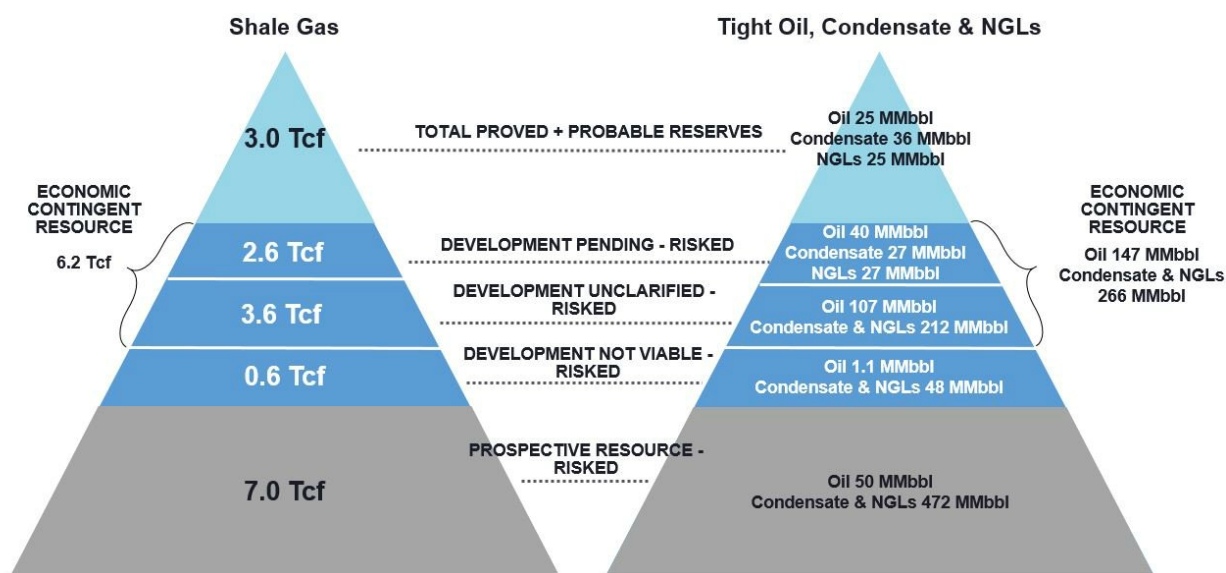
NGLs ECR was evaluated on an unrisks and risks basis in 2016 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risks development pending NGLs ECR totaled 54 MMbbl and risks development unclarified NGLs ECR totaled 212 MMbbl. The risks prospective NGLs ECR totaled 472 MMbbl.

On the tight oil-bearing lands at Tower, Red Creek and Attachie, TPiIP increased nine per cent to 10.5 MMbbl and DPIIP increased eight per cent to 6.2 MMbbl.

Tight Oil ECR was evaluated on an unrisks and risks basis in 2016 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risks development pending tight oil ECR totaled 40 MMbbl and risks development unclarified tight oil ECR totaled 107 MMbbl. The risks prospective tight oil ECR totaled 50 MMbbl.

Risking of the economic contingent resources included a quantitative assessment of the economic status, the recovery technology status, the project evaluation scenario status, and the development time frame. Risking of the prospective resources included a quantitative assessment of these same factors, as well as a quantitative assessment of the chance of discovery.

**Exhibit 1**



**Table 8**

<b>Shale Gas Resources</b> <sup>(1)(2)(3)(4)</sup>		
(Tcf)	<b>2016</b>	<b>2015</b>
Total Petroleum Initially-in-Place	<b>101.5</b>	90.0
Discovered Petroleum Initially-in-Place <sup>(5)</sup>	<b>41.8</b>	41.4
Undiscovered Petroleum Initially-in-Place <sup>(6)</sup>	<b>59.7</b>	48.6

- (1) TPIIP, DPIIP and UPIIP have been estimated using a one per cent porosity cut-off in both 2016 and 2015, which means that essentially all gas-bearing rock has been incorporated into the calculations.
- (2) The resource categories in this table do not include free crude oil or liquids.
- (3) All volumes listed in the table are company gross and raw gas volumes.
- (4) All numbers are "Best Estimates".
- (5) There is uncertainty that it will be commercially viable to produce any portion of the resources.
- (6) 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.

**Table 9**

<b>Tight Oil Resources</b> <sup>(1)(2)(3)(4)</sup>		
(MMbbl)	<b>2016</b>	<b>2015</b>
Total Petroleum Initially-in-Place	<b>10,529</b>	9,688
Discovered Petroleum Initially-in-Place <sup>(5)</sup>	<b>6,180</b>	5,736
Undiscovered Petroleum Initially-in-Place <sup>(6)</sup>	<b>4,349</b>	3,952

- (1) TPIIP, DPIIP and UPIIP have been estimated in 2016 using a one per cent porosity cut-off for tight oil and using a three per cent cut-off in 2015.
- (2) All volumes listed in the table are company gross.
- (3) The tight oil DPIIP is a Stock Tank Barrel.
- (4) All numbers are "Best Estimates".
- (5) There is uncertainty that it will be commercially viable to produce any portion of the resources.
- (6) 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.

Table 10

Reserves and Risked and Unrisked ECR <sup>(1)(2)(3)(4)(5)(6)</sup>	2016			2015		
	Chance of Development	Best Estimate Unrisked	Best Estimate Risked	Chance of Development	Best Estimate Unrisked	Best Estimate Risked
<b>Shale Gas (Tcf)</b>						
Reserves	100%	3.0	3.0	100%	2.6	2.6
Development Pending ECR	91%	2.9	2.6	92%	2.6	2.4
Development Unclarified ECR	74%	4.8	3.6	76%	4.4	3.3
<b>NGLs (MMbbl)</b>						
Reserves	100%	61.9	61.9	100%	42.3	42.3
Development Pending ECR	91%	58.6	53.5	94%	39.1	36.9
Development Unclarified ECR	74%	286.7	212.5	76%	265.1	200.9
<b>Tight Oil (MMbbl)</b>						
Reserves	100%	25.2	25.2	100%	22.7	22.7
Development Pending ECR	95%	42.0	39.9	95%	34.8	33.1
Development Unclarified ECR	69%	154.3	106.9	79%	163.2	129.0

(1) All DPIIP, other than cumulative production, reserves, and ECR, has been categorized as unrecoverable. Cumulative raw production to year-end 2016 was 0.7 Tcf of shale gas and 5.6 MMbbl of tight oil, all of which are immaterial in relation to the reserves and ECR magnitude. NGLs cumulative production is calculated based on current NGLs recoveries.

(2) All volumes listed in the table are company gross and sales volumes.

(3) All numbers are "Best Estimates".

(4) All ECR have been risked for chance of development. For ECR, the chance of development is defined as the probability of a project being commercially viable. In quantifying the chance of development, factors that were assessed quantitatively to be less than one in the risking calculation included the economic status, the project evaluation scenario status, and the development time frame. The chance of development is multiplied by the unrisked resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of development is an uncertain value that should be used with caution.

(5) For reserves, the volumes under the heading "*Best Estimate*" are 2P reserves.

(6) There is uncertainty that it will be commercially viable to produce any portion of the resources.

**An estimate of risked NPV of future net revenues of the development pending contingent resources subclass only is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of ARC proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked NPV of future net revenue will be realized. The other subclasses of resources are not included in this NPV, and therefore, this is not reflective of the value of the resource base.**

**Table 11**

	2016			2015		
	Chance of Development	Best Estimate Unrisked	Best Estimate Risked	Chance of Development	Best Estimate Unrisked	Best Estimate Risked
<b>Risked and Unrisked ECR Development Pending</b> <sup>(1)(2)(3)(4)</sup>						
Shale Gas (Tcf)	91%	2.9	2.6	92%	2.6	2.4
NGLs (MMbbl)	91%	58.6	53.5	94%	39.1	36.9
Tight Oil (MMbbl)	95%	42.0	39.9	95%	34.8	33.1
Oil Equivalent (MMboe)	92%	577.3	528.9	92%	509.4	470.7
<b>Before-tax NPV</b> (\$ millions)						
Undiscounted		11,683	10,693		10,624	9,890
Discounted at 5%		4,431	4,068		3,447	3,203
Discounted at 10%		1,992	1,831		1,247	1,154
Discounted at 15%		1,006	925		443	406
Discounted at 20%		552	508		114	100
<b>After-tax NPV</b> (\$ millions)						
Undiscounted		8,566	7,841		7,728	7,194
Discounted at 5%		3,185	2,924		2,431	2,258
Discounted at 10%		1,390	1,277		812	750
Discounted at 15%		675	620		229	208
Discounted at 20%		352	323		(3)	(8)

(1) All volumes listed in the table are company gross and sales volumes.

(2) 2016 NPV as per GLJ Independent Resources Evaluation as of December 31, 2016 and based on GLJ forecast pricing at January 1, 2017. 2015 NPV as per GLJ Independent Resources Evaluation as of December 31, 2015 and based on GLJ forecast pricing at January 1, 2016.

(3) Risk in the above table is the chance of development. Contingent resources are discovered resources by definition.

(4) There is uncertainty that it will be commercially viable to produce any portion of the resources.

The estimated cost to bring on commercial production the Development Pending Contingent Resources for all three product types is approximately \$4.0 billion (when discounted at 10 per cent, the estimated cost is approximately \$1.4 billion). The expected timeline to bring these resources on production is between two and 10 years. The ECR are expected to be recovered using the same technology in horizontal drilling and multi-stage fracturing that ARC has already proven to be effective in the Montney in northeast British Columbia.

**Table 12**

	2016			2015		
	Chance of Commerciality	Best Estimate Unrisked	Best Estimate Risked	Chance of Commerciality	Best Estimate Unrisked	Best Estimate Risked
<b>Prospective Resources</b> <sup>(1)(2)(3)(4)(5)</sup>						
Shale Gas (Tcf)	48%	14.7	7.0	49%	10.7	5.3
NGLs (MMbbl)	45%	1,042.1	471.5	46%	690.8	319.3
Tight Oil (MMbbl)	41%	122.5	49.9	68%	119.0	81.3
Oil Equivalent (MMboe)	47%	3,612.1	1,686.6	49%	2,587.1	1,279.2

(1) All UPIIP, other than prospective resources, has been categorized as unrecoverable.

(2) All volumes listed in the table are company gross and sales volumes.

(3) Prospective resources have been risked for chance of development and chance of discovery. For prospective resources, the chance of development multiplied by the chance of discovery is defined as the probability of a project being commercially viable. In quantifying the chance of commerciality, factors that were assessed quantitatively to be less than one in the risking calculation included the economic status, the project evaluation scenario status and the development time frame, along with the overall chance of discovery. The chance of commerciality is multiplied by the unrisked prospective resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of commerciality is an uncertain value that should be used with caution.

(4) All prospective resources are subclassified as the prospect maturity subclass.

(5) 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.

Based upon the foregoing analysis, as well as ARC's expertise in the Montney formation in northeast British Columbia, it is expected that significant additional reserves will be developed in the future with continued drilling success on currently undeveloped Montney acreage, together with further development, completions refinements and improved economic conditions. Historic drilling success and recoveries on the more fully-developed Montney acreage, abundant well log and production test data, and the application of increased drilling densities, support ARC's belief that significant additional resources will be recovered. Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for additional resources to be recovered in the future. The principal risks that would inhibit the recovery of additional reserves relate to the potential for variations in the quality of the Montney formation where minimal well data currently exists, access to the capital which would be required to develop the resources, low commodity prices that would curtail the economics of development and the future performance of wells, regulatory approvals, access to the required services at the appropriate cost, and the effectiveness of well fracturing technology and applications. For ECR to be converted to reserves, Management and the Board of Directors need to ascertain commercial production rates, then develop firm plans, including timing, infrastructure, and the commitment of capital. Confirmation of commercial productivity is generally required before the Company can prepare firm development plans and commit required capital for the development of the ECR. Additional contingencies are related to the current lack of infrastructure required to develop the resources in a relatively quick time frame. As continued delineation occurs, some resources currently classified as ECR are expected to be re-classified to reserves.

## DEFINITIONS OF OIL AND GAS RESOURCES AND RESERVES

**Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on 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 classified according to the degree of certainty associated with the estimates as follows:

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

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

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

**Resources** encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total Resources" is equivalent to "Total Petroleum Initially-in-Place". Resources are classified in the following categories:

**Total Petroleum Initially-in-Place ("TPIIP")** 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.

**Discovered Petroleum Initially-in-Place ("DPIIP")** 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 DPIIP includes production, reserves, and contingent resources; the remainder is unrecoverable.

**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.

**Economic Contingent Resources ("ECR")** are those contingent resources which are currently economically recoverable.

**Project Maturity Subclass Development Pending** is defined as a contingent resource that has been assigned a high chance of development and the resolution of final conditions for development are being actively pursued.

**Project Maturity Subclass Development Unclassified** is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined.

**Undiscovered Petroleum Initially-in-Place ("UPIIP")** 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 UPIIP is referred to as "prospective resources" and 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.

**Unrecoverable** is that portion of DPIIP and UPIIP 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.

**Uncertainty Ranges** are described by the COGE Handbook as low, best, and high estimates for reserves and resources. The **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 per cent probability that the quantities actually recovered will equal or exceed the best estimate.

## **INFORMATION REGARDING DISCLOSURE ON OIL AND GAS RESERVES, RESOURCES AND OPERATIONAL INFORMATION**

All amounts in this news release are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a six Mcf to one barrel ratio. The boe rate is based on an energy equivalency conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The boe rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on company gross reserves using forecast prices and costs.

This news release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by ARC as set out below. These metrics are "reserve replacement", "reserve life index", "finding and development costs", "finding, development and acquisition costs", "operating netbacks", "finding and development recycle ratio", and "finding, development and acquisition costs recycle ratio". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare ARC's performance over time, however, such measures are not reliable indicators of ARC's future performance and future performance may not compare to the performance in previous periods.

- "Reserve replacement" is calculated by dividing the annual 2P reserve adds (in boe) by ARC's annual production (in boe). Management uses this measure to determine the relative change of its reserves base over a period of time.
- "Reserve life index" or "RLI" is calculated by dividing the reserves (in boe) in the referenced category by the midpoint production guidance (in boe) for the following year. Management uses this measure to determine how long the booked reserves will last at current production rates if no further reserves were added.
- "Finding and development costs" or "F&D costs" are calculated by dividing the sum of the total capital expenditures for the year (in dollars) by the change in reserves within the applicable reserves category (in boe). F&D costs, including FDC, includes all capital expenditures in the year as well as the change in FDC required to bring the reserves within the specified reserves category on production.
- "Finding, development and acquisition costs" or "FD&A costs" are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in boe). FD&A costs, including FDC, includes all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in FDC required to bring the reserves within the specified reserves category on production.

- Both F&D and FD&A costs take into account reserves revisions and capital revisions during the year. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year. F&D costs and FD&A costs have been presented in this news release because acquisitions and dispositions can have a significant impact on ARC's ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of its cost structure. Management uses F&D and FD&A as measures of its ability to execute its capital programs (and success in doing so) and of its asset quality.
- Operating netback is calculated using production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and operating expenses, calculated on a per boe equivalent basis. Management uses this measure to benchmark operating results between areas and/or time periods.
- "Finding and development recycle ratio" or "F&D recycle ratio" is calculated by dividing the operating netback (in dollars per boe) by the F&D costs (in dollars per boe) for the year.
- "Finding, development and acquisition costs recycle ratio" or "FD&A recycle ratio" is calculated by dividing the operating netback (in dollars per boe) by the FD&A costs (in dollars per boe) for the year.
  - ARC uses both F&D recycle ratio and FD&A recycle ratio as an indicator of profitability of its oil and gas activities.

ARC's oil and gas reserves statement for the year ended December 31, 2016, which will include complete disclosure of its oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within ARC's AIF which will be available on or before March 31, 2017 on ARC's website at [www.arcresources.com](http://www.arcresources.com) and on SEDAR at [www.sedar.com](http://www.sedar.com).

This news release contains references to estimates of resources other than reserves in the Montney region in northeast British Columbia, including lands in Pouce Coupe in Alberta, which are not, and should not be confused with, oil and gas reserves. See *"Definitions of Oil and Gas Resources and Reserves"*.

Projects have not been defined to develop the resources in the Evaluated Areas as at the evaluation date. Such projects, in the case of the Montney resource development, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, ARC's policy of orderly development on a staged basis, the timing of the growth of third-party infrastructure, the short- and long-term view of ARC on oil and gas prices, the results of exploration and development activities of ARC and others in the area and possible infrastructure capacity constraints.

ARC's belief that it will establish significant additional reserves over time with conversion of DPIIP into ECR, ECR into 2P reserves, and probable reserves into proved reserves, is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading *"Forward-looking Information and Statements"*.

### **Notice to US Readers**

The oil and natural gas reserves contained in this news release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission ("the SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves, each as defined in NI 51-101. Accordingly, proved reserves disclosed in this news release may not be comparable to US standards, and in this news release, ARC has disclosed reserves designated as "probable reserves" and "proved plus probable reserves". Probable reserves are higher-risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The SEC's guidelines strictly prohibit reserves in these categories from being included in filings with the SEC that are required to be prepared in accordance with US disclosure requirements. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalties and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Moreover, ARC has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC generally requires that prices and costs be held constant at levels in effect at the date of the reserve report. As a consequence of the foregoing, ARC's reserve estimates and production volumes in this news release may not be comparable to those made by companies utilizing US reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources, whereas Canadian issuers may disclose resource volumes. Resources are different than, and should

not be construed as, reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, resources, see above.

## **FORWARD-LOOKING INFORMATION AND STATEMENTS**

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "strategy", and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the recognition of significant additional reserves under the heading "2016 Independent Reserves Evaluation" and the recognition of significant resources under the heading "NE BC Montney Resources Evaluation", the volumes and estimated value of ARC's oil and gas reserves; the future net value of ARC's reserves; the future development costs; the future abandonment and reclamation costs; the 2017 capital expenditure budget, the life of ARC's reserves; the volume and product mix of ARC's oil and gas production; future oil and natural gas prices; future results from operations and operating metrics; and future development, exploration, acquisition and development activities (including drilling plans) and related production expectations.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of ARC including, without limitation: that ARC will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities are consistent with past results; the continued and timely development of infrastructure in areas of new production; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of ARC's reserve and resource volumes; certain commodity price and other cost assumptions; and the continued availability of adequate debt and equity financing and cash flow to fund its planned expenditures. There are a number of assumptions associated with the development of the Evaluated Areas, including the quality of the Montney reservoir, continued performance from existing wells, future drilling programs and performance from new wells, the growth of infrastructure, well density per section, and recovery factors and development necessary involves known and unknown risks and uncertainties, including those risks identified in this news release. ARC believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; the early stage of development of some areas in the Evaluated Areas; the potential for variation in the quality of the Montney formation, changes in the demand for or supply of ARC's products; unanticipated operating results or production declines; unanticipated results from ARC's exploration and development activities; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of ARC or by third-party operators of ARC's properties, increased debt levels or debt service requirements; inaccurate estimation of ARC's oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in ARC's public disclosure documents (including, without limitation, those risks identified in this news release and in ARC's AIF).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and none of ARC or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

ARC Resources Ltd. is one of Canada's largest conventional oil and gas companies with an enterprise value of approximately \$7.4 billion. ARC's common shares trade on the TSX under the symbol ARX.

ARC RESOURCES LTD.

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