Crescent Point

PRESS RELEASE

CRESCENT POINT ANNOUNCES YEAR-END 2016 RESULTS, EXCEEDS ANNUAL PRODUCTION GUIDANCE AND REPLACES 137 PERCENT OF PRODUCTION AT $7.02 PER BOE FINDING & DEVELOPMENT COSTS

(All financial figures are approximate and in Canadian dollars unless otherwise noted)

February 23, 2017 CALGARY, ALBERTA. Crescent Point Energy Corp. ("Crescent Point" or the "Company") (TSX and NYSE: CPG) is pleased to announce its operating and financial results for the year ended December 31, 2016. The Company also announces that its audited financial statements and management's discussion and analysis for the year ended December 31, 2016, will be available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com, on EDGAR at www.sec.gov/edgar.shtml and on Crescent Point's website at www.crescentpointenergy.com.

KEY HIGHLIGHTS

- Exceeded annual average production guidance with development capital expenditures on budget.
- Completed one of the Company's strongest years operationally, developing two new plays in the Uinta and Williston basins.
- Added over 1,000 high-quality new internally identified locations to its corporate drilling inventory.
- Improved efficiencies and lowered its cost structure, resulting in Proved plus Probable ("2P") Finding and Development ("F&D") costs of $7.02 per boe, excluding acquisitions and including changes in future development capital ("FDC").
- Spent less than funds flow from operations to achieve a total payout ratio of 89 percent and lowered net debt to funds flow from operations by more than 0.5 times.
- Nominating a new director at the upcoming Annual General meeting as part of the Company's board renewal process.
- 2017 focus on organic growth, new play development, improved investor communication and shareholder engagement.

OPERATIONAL HIGHLIGHTS

- Crescent Point achieved average production of 165,097 boe/d in fourth quarter 2016 with December exit production greater than 167,000 boe/d. Annual average production of 167,764 boe/d exceeded the Company's 2016 guidance while total development capital expenditures of $1.10 billion, excluding land acquisitions, was in line with budget.
- The Company's step-out drilling program successfully contributed to the addition of approximately 1,000 new internally identified drilling locations during 2016. These new locations rank largely in the top quartile of Crescent Point's portfolio and are primarily situated in the Company's Williston Basin, southwest Saskatchewan and Uinta Basin resource plays. At year-end 2016, the Company's internally identified corporate drilling inventory totaled over 8,000 net locations.
- In the Uinta Basin, Crescent Point successfully drilled nine net one-mile horizontal wells during 2016 and internally identified approximately 120 net horizontal follow-up locations within the Castle Peak zone. The Company's Castle Peak horizontal type well has a 90-day initial production rate of approximately 650 boe/d and generates economics that rank in the top quartile of the Company's drilling inventory. Crescent Point will be building on this success by continuing to optimize its drilling and completions process. The Company forecasts to drill approximately 25 net one- and two-mile horizontal wells in the Uinta Basin in 2017.
- Crescent Point improved drilling efficiencies in each of its core areas during 2016. Average drilling days in both the Williston Basin and the Shaunavon resource play improved by approximately 11 percent compared to 2015.
- In late 2016, Crescent Point piloted its new Injection Control Device ("ICD") technology, which has demonstrated encouraging results with three times the amount of water injectivity compared to prior technology. As a result of this efficiency improvement, the Company is installing additional ICD systems in its Williston Basin and southwest Saskatchewan resource plays. Results from these new installations are expected in the second half of the year.

RESERVES HIGHLIGHTS

- Crescent Point generated 2P F&D costs of $7.02 per boe, excluding acquisitions and including changes in FDC. This represents a recycle ratio of 3.2 times based on the Company's 2016 average netback before hedging of $22.18 per boe. Improved efficiencies during 2016 resulted in a 2P F&D cost reduction of approximately 30 percent compared to 2015.
- Including acquisitions net of dispositions, 2P Finding Development and Acquisition ("FD&A") costs totaled $10.87 per boe, including changes in FDC, for a recycle ratio of 2.0 times.
- On a 2P basis, Crescent Point replaced 137 percent of 2016 production and increased reserves to 958.5 million boe ("MMboe") (90 percent oil and liquids). The Company added 66.4 MMboe of organic 2P reserves. Including acquisitions net of dispositions, Crescent Point added 84.2 MMboe of 2P reserves.

- Reserves attributed to waterflood accounted for 16 percent of organic 2P reserves additions. In 2016, Crescent Point added 10.5 MMboe of 2P reserves attributed to waterflood projects, the fourth consecutive year the Company's independent evaluators have recognized tight rock waterflood reserves additions. Since 2013, Crescent Point has added over 23 MMboe of 2P waterflood reserves across the Company.
- Crescent Point reduced its FDC, excluding acquisitions, by $672.5 million or approximately 10 percent on a 2P basis.
- The Company generated a before tax 2P Net Asset Value ("NAV") of $24.14 per fully diluted share, discounted at 10 percent.
- Excluding changes in FDC, the Company generated a five-year weighted average F&D cost of $20.16. This represents a five-year weighted average recycle ratio of 1.9 times based on the Company's five-year weighted average netback before hedging of $38.00 per boe.
- On a Proved ("1P") basis, Crescent Point replaced 113 percent of 2016 production and increased 1P reserves to 600.2 MMboe (90 percent oil and liquids). Including changes in FDC, 1P F&D totaled $11.05 per boe, a reduction of 21 percent compared to 2015. This represents a recycle ratio of 2.0 times. Overall, 1P reserves accounted for 63 percent of total 2P reserves.
- On a Proved Developed Producing ("PDP") basis, Crescent Point replaced 102 percent of 2016 production and increased PDP reserves to 364.2 MMboe (89 percent oil and liquids). PDP F&D totaled $20.03 per boe, including changes in FDC, representing a recycle ratio of 1.1 times.

FINANCIAL HIGHLIGHTS

- Funds flow from operations totaled $422.0 million, or $0.77 per share diluted, in fourth quarter 2016. This is a 15 percent increase over third quarter 2016. Cash dividends paid were $0.09 per share during the quarter, resulting in a payout ratio of 12 percent.
- Crescent Point spent less than its funds flow from operations and achieved a total payout ratio of 89 percent in 2016 based on development capital expenditures of $1.14 billion and $260.3 million of cash dividends paid. This represents a $422.9 million, or 27 percent reduction, in development capital expenditures from 2015. Based on 2017 guidance, the Company estimates a total payout ratio of approximately 91 percent at current strip prices.
- Crescent Point continued to reduce its cost structure in 2016. Annual operating costs of $11.27 per boe were eight percent lower than the Company's original budget of $12.25 per boe. Capital costs also improved for a second consecutive year, further enhancing economics within Crescent Point's asset base. Since late 2014, Crescent Point has successfully reduced capital costs per well by approximately 40 percent on average.
- In September 2016, Crescent Point completed a bought deal financing for gross proceeds of $650 million. The Company initially used these proceeds to reduce bank indebtedness and further protect itself against the downside risks of the uncertain commodity price environment. Net debt to funds flow from operations improved by more than 0.5 times as a result of this financing. As at December 31, 2016, Crescent Point's net debt totaled approximately $3.7 billion. The Company retains approximately $1.9 billion of unutilized credit capacity on its covenant-based, unsecured credit facility and has no material near-term debt maturities.
- As part of its risk management program, Crescent Point has hedged 11.8 million barrels of oil since third quarter 2016. As at February 20, 2017, the Company has 39 percent of its 2017 oil production, net of royalty interest, hedged at a weighted average market value price of approximately CDN$72.00/bbl. For the first half of 2018, Crescent Point has 12 percent of its oil production hedged at a weighted average market value price of approximately CDN$74.00/bbl. The Company also has a significant amount of its natural gas production hedged through 2019 at a weighted average price of CDN$2.92 per GJ.
- Crescent Point's fourth quarter net loss of $510.6 million included a $457.0 million non-cash after-tax ($611.4 million pre-tax) net impairment charge, primarily resulting from a lower future forecast for commodity prices at December 31, 2016 compared to December 31, 2015, offset by significant technical and development reserves additions. This after-tax net impairment represents approximately three percent of the Company’s total assets as at December 31, 2016. This charge does not impact Crescent Point's funds flow from operations or the amount of credit available under its bank credit facilities. Under International Financial Reporting Standards ("IFRS"), these impairment charges can be reversed in future periods if commodity prices recover and the future forecast for pricing improves. The Company's fourth quarter net loss also included an unrealized loss on derivatives of $138.7 million due to changes in the futures market for commodity prices and foreign exchange in comparison to third quarter 2016.
- The Company is pleased to announce that Mr. Ted Goldthorpe will be nominated for election to its Board of Directors at the upcoming Annual General Meeting. Mr. Goldthorpe is a financial professional who is currently Managing Partner of Global Credit Business for BC Partners. Previous to that, he held several senior positions with Apollo Investment Corporation and Goldman Sachs & Co. Mr. Goldthorpe's nomination is part of Crescent Point’s ongoing board renewal process led by the Governance Committee of the Board. Since 2014, the Company has added five new independent Board members from various professional backgrounds. As part of this renewal process, Mr. Greg Turnbull is retiring from the Board and will not be standing for re-election in 2017. Crescent Point thanks Mr. Turnbull for his valued contributions over the past 15 years.

OUTLOOK

Crescent Point had an excellent fourth quarter and full year operationally. The Company's production exceeded its 2016 guidance with development capital expenditures on budget. Crescent Point was successful in growing organic 2P reserves and expanding its new plays during a year of extreme uncertainty in the oil price environment.

"2016 was about improving our financial position in a volatile commodity price environment while successfully executing the expansion of our new plays," said Scott Saxberg, president and CEO of Crescent Point. "We spent below our funds flow from operations and generated a total payout ratio of 89 percent. We also issued $650 million in equity to pay down our debt and protect against the potential downside risk of uncertainty created by OPEC and the US election."

The Company's operational success was highlighted by the addition of over 1,000 new internally identified net locations that more than replaced its annual drilling program. Reserves growth more than replaced Crescent Point's annual production at an F&D cost of $7.02 per boe, including changes in FDC. This represents a recycle ratio of 3.2 times, highlighting management's strategic capital allocation and the Company's high-netback, high-quality asset base.

"Our 2016 reserves additions were highly profitable with a top-quartile recycle ratio that demonstrates our company's strong technical focus," said Saxberg. "We added organic reserves through a successful drilling program, the advancement of our waterflood programs and new technological advancements. In fact, we have now generated over 644 million boe of organic reserves additions since our inception in 2001, representing close to 70 percent of our current reserve base."

In 2017, Crescent Point plans to drill approximately 670 net wells and generate annual average production of 172,000 boe/d with an exit rate of 183,000 boe/d. The Company has risked its guidance for production from horizontal wells in the Uinta Basin and any benefit from its ICD waterflood system, which is currently being implemented throughout the Williston Basin and southwest Saskatchewan resource plays. Crescent Point is committed to advancing its waterflood programs and ICD technology, which creates a dual-track growth plan that positions the Company for long-term stability by managing its decline rate as it continues to grow production.

The Company is currently outperforming its first quarter guidance of 170,000 boe/d and plans to revisit its annual production guidance following spring break-up. Crescent Point's 2017 development capital expenditures guidance of $1.45 billion includes an average increase in assumed capital costs of approximately five percent. The Company will continue to monitor service costs within its drilling program throughout the year.

"We forecast exit to exit production growth of approximately 10 percent per share in 2017," said Saxberg. "We remain focused on delivering per share growth for our shareholders and are currently ahead of our first quarter estimates. Our 2017 budget is expected to deliver production growth that will more than replace the short-term dilution from our September 2016 equity financing."

In 2016, Crescent Point was successful in selling non-core assets and will continue to explore disposition opportunities within its asset base during 2017 and going forward.

Management remains committed to maximizing shareholder return through its total return strategy of long-term growth plus dividend income. One of the Company's key focuses for 2017 will be improving investor communication. Crescent Point is proud of its success over the past 16 years and its entrepreneurial drive for continued outperformance through its strong technical focus.

"We have made it a priority to improve communication and engagement with our shareholders in 2017," said Saxberg. "We spent significant time speaking with our shareholders last year and incorporated their feedback into our changes to compensation, governance and corporate messaging. We remain committed to being transparent and accountable with our investors."

OPERATIONS REVIEW

Fourth Quarter Operations Highlights and Summary

In fourth quarter and throughout 2016, Crescent Point continued to execute its long-term growth strategy through the development and acquisition of high-quality, long-life, light and medium oil weighted properties.

Drilling Results

The following table summarizes Crescent Point's drilling results for the three months and year ended December 31, 2016:

Three months ended December 31, 2016	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Williston Basin (1)	-	135	-	1	-	136	121.9	100
Southwest Saskatchewan	-	113	-	-	-	113	99.2	100
Uinta Basin (1)	-	9	-	-	-	9	4.2	100
Other	-	4	-	-	-	4	4.0	100
Total	-	261	-	1	-	262	229.3	100

Year ended December 31, 2016	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Williston Basin (1)	-	378	-	2	-	380	344.5	100
Southwest Saskatchewan	-	294	-	1	-	295	270.3	100
Uinta Basin (1)	-	25	-	-	-	25	15.0	100
Other	-	15	-	-	-	15	15.0	100
Total	-	712	-	3	-	715	644.8	100

(1) The net well count is subject to final working interest determination

Williston Basin

During fourth quarter, Crescent Point drilled 136 (121.9 net) wells in the Williston Basin. Within each of the basin's resource plays, the Company continues to focus on low-risk, high-return infill development in Viewfield Bakken, step-out drilling in Flat Lake and down-spacing programs in North Dakota.

Crescent Point improved operating efficiencies within each of its Williston Basin resource plays throughout 2016. By fourth quarter, average drilling days improved approximately 11 percent compared to 2015. This reflects the positive impact of Crescent Point's optimization programs, efficiencies achieved from increased drilling activity within the basin and the successful application of technologies such as new drill bits and motors.

Crescent Point also internally identified over 700 net new drilling locations in the Williston Basin during 2016. These new locations are primarily in the Company's multi-zone Flat Lake resource play, including approximately 300 net locations acquired in third quarter 2016 as part of the Company's strategic Flat Lake acquisition. The Flat Lake resource play continues to be a growth area for Crescent Point with strong netbacks that were 24 percent higher than the corporate average during 2016.

In 2017, the Company plans to drill approximately 350 net wells in the Williston Basin. This is expected to result in exit production growth of approximately five percent and funds flow from operations in excess of capital expenditures of approximately $0.5 billion based on current strip prices. The Company's 2017 budget includes step-out wells, a down-spacing program and infill drilling to further extend the basin's boundaries and capitalize on its strong economics. Crescent Point also plans to test new technologies during the year, including its ICD waterflood system.

Southwest Saskatchewan

Crescent Point drilled 113 (99.2 net) oil wells during fourth quarter in southwest Saskatchewan. The Company continues optimizing the number of stages and tonnage per stage in the Shaunavon resource play. Since implementing over 30 stages per well in its completions process, the Lower Shaunavon has demonstrated improved production results compared to the expected type well.

Crescent Point improved operational efficiencies in southwest Saskatchewan and internally identified over 500 net new drilling locations during 2016. These new locations are a result of the Company's successful expansion of the Shaunavon resource play's economic boundaries and its down-spacing program in the Saskatchewan Viking resource play.

Crescent Point plans to grow 2017 exit production by approximately 10 percent in southwest Saskatchewan through drilling 270 net wells. The Company plans to focus on continued efficiency improvements, step-out drilling and the testing of new technologies such as its ICD waterflood system. In addition, Crescent Point is implementing closeable sliding sleeves in the Saskatchewan Viking resource play. This is expected to reduce well clean out costs similar to earlier results achieved in the Viewfield Bakken and Shaunavon resource plays. The Company will continue to test extended reach horizontals in an effort to enhance and further improve the economic development of the Viking resource play.

Uinta Basin

Crescent Point drilled four one-mile horizontal wells during fourth quarter in the Uinta Basin, each targeting the Castle Peak zone. Production results, including the results from wells completed during fourth quarter 2016, continue to demonstrate performance in line with the Company's expected horizontal type curve, generating a 90-day initial production rate of approximately 650 boe/d. Since late 2014, Crescent Point has drilled 15 one-mile horizontal wells in the basin, including eight targeting the Castle Peak zone.

During 2016, the Company added 120 net internally identified horizontal locations in the Castle Peak zone to its corporate drilling inventory, assuming spacing of four one-mile wells per section. This represents the Company's first operated horizontal drilling inventory in the basin and demonstrates Crescent Point's increased geological knowledge and overall advancement of this resource play. Crescent Point was successful in growing 2P reserves by approximately 10 percent during 2016, despite spending only $12.3 million of capital during the first half of the year. Overall, 86 percent of the Company's Uinta Basin budget was spent during the second half of 2016, reflecting its increasing confidence in production data, improved well economics and the play's accelerating momentum. Since entering the basin in late 2012, the Company has organically increased 2P reserves by over 80 percent.

During 2017, Crescent Point plans to drill approximately 25 net horizontal wells in the Uinta Basin, up from nine in 2016. The Company's Uinta Basin program is expected to drive exit production growth of approximately 50 percent. Within its 2017 budget, the Company plans to continue delineating this resource play for future horizontal development beyond the Castle Peak zone. Crescent Point also intends to test proppant usage, new completions techniques and increased lateral lengths in an effort to further improve upon the encouraging production rates and efficiencies witnessed to date.

WATERFLOOD UPDATE

Crescent Point's waterflood programs continue to improve estimated ultimate recoveries and economic values while reducing decline rates and limiting required maintenance capital expenditures. The Company increased waterflood reserves for the fourth consecutive year, as recognized by its independent evaluators, by adding approximately 10.5 MMboe of 2P reserves during 2016. Independent evaluators have recognized 23.0 MMboe of 2P reserves attributed to waterflood projects since 2013, or approximately seven percent of Crescent Point's total organic 2P reserve additions over that time frame. Of these waterflood additions, approximately 95 percent are from Crescent Point's Viewfield Bakken and Shaunavon resource plays. Reserves attributed to waterflood accounted for 16 percent of organic 2P reserves additions in 2016.

During late 2016, Crescent Point continued to test its ICD system. The Company's initial pilot demonstrated encouraging results with three times the amount of water injectivity without increasing the percentage of water produced in offsetting wells compared to prior technology. The Company expects increased water injectivity and enhanced distribution of injected water will help manage reservoir pressure and may further reduce decline rates and increase estimated ultimate recoveries.

The success of Crescent Point's initial pilot led the Company to implement additional ICD systems throughout the Williston Basin and southwest Saskatchewan in late fourth quarter. The Company plans to install additional ICD systems by the end of second quarter 2017 and expects to receive corresponding production data in the second half of the year. At the end of 2016, the Company had approximately 300 injection wells installed under its prior technology throughout its Bakken and Shaunavon waterflood programs. Assuming the continued success of the ICD technology, the existing injection wells would become candidates for additional conversions to the ICD system without the need to take existing producing wells offline.

RESERVES

The Company's reserves were independently evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Limited ("Sproule") as at December 31, 2016, and were aggregated by GLJ. The reserves evaluation and reporting was conducted in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and - *National Instrument 51-101 Standards for Disclosure of Oil and Gas Activities* ("NI 51-101").

In 2016, Crescent Point generated positive technical and development reserves revisions for the 15th consecutive year since inception. Reserves results in 2016 include additions in the Company's core Williston Basin, southwest Saskatchewan and Uinta Basin resource plays. During the year, Crescent Point invested $1.14 billion into the development and expansion of its asset base, including funds invested in facilities, land and seismic. The Company added 66.4 MMboe of 2P reserves, excluding reserves added through acquisitions, and generated F&D costs of $7.02 per 2P boe, including changes in FDC. This represents a recycle ratio of 3.2 times. Excluding changes in FDC, 2P F&D costs totaled $17.15 per boe, resulting in a recycle ratio of 1.3 times.

Summary of Reserves

As at December 31, 2016 (1) (2) (3) (4)

	Tight Oil (Mbbls)		Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas Liquids (Mbbls)	
Reserves Category	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**
Proved Developed Producing	157,953	143,792	110,880	96,958	20,580	18,151	36,037	32,159
Proved Developed Non-Producing	8,046	7,296	4,419	4,018	230	202	1,249	1,121
Proved Undeveloped	132,529	118,374	43,998	40,873	2,006	1,640	19,813	17,487
Total Proved	298,527	269,461	159,298	141,850	22,816	19,993	57,099	50,767
Total Probable	184,814	164,251	100,034	88,832	7,329	6,404	31,714	28,247
Total Proved plus Probable	483,341	433,712	259,331	230,682	30,145	26,397	88,813	79,014

	Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Total (Mboe)	
Reserves Category	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**
Proved Developed Producing	132,966	121,115	99,263	89,579	364,154	326,175
Proved Developed Non-Producing	5,827	5,179	3,083	2,711	15,428	13,952
Proved Undeveloped	108,708	94,944	24,915	22,751	220,617	197,990
Total Proved	247,501	221,238	127,261	115,041	600,199	538,117
Total Probable	138,953	123,028	67,441	60,720	358,289	318,359
Total Proved plus Probable	386,455	344,266	194,702	175,761	958,489	856,476

(1) Based on Sproule's December 31, 2016, escalated price forecast.

(2) "Gross Reserves" are the total Company's working-interest share before the deduction of any royalties and without including any royalty interest of the Company.

(3) "Net Reserves" are the total Company's interest share after deducting royalties and including any royalty interest.

(4) Numbers may not add due to rounding.

Summary of Before and After Tax Net Present Values

As at December 31, 2016 (1) (2)

	Before Tax Net Present Value ($ millions)					After Tax Net Present Value ($ millions)				
	Discount Rate					Discount Rate				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Developed Producing	11,881	8,941	7,217	6,089	5,295	11,260	8,572	6,983	5,932	5,184
Proved Developed Non-Producing	446	360	300	256	224	336	280	241	211	189
Proved Undeveloped	5,209	3,413	2,302	1,583	1,098	3,958	2,539	1,656	1,086	703
Total Proved	17,536	12,713	9,819	7,929	6,616	15,554	11,392	8,880	7,230	6,076
Total Probable	13,390	7,855	5,255	3,813	2,919	9,522	5,570	3,714	2,685	2,049
Total Proved plus Probable	30,926	20,569	15,074	11,741	9,535	25,076	16,962	12,594	9,915	8,125

(1) Based on Sproule's December 31, 2016, escalated price forecast.

(2) Numbers may not add due to rounding.

Before Tax Net Asset Value per Share, Fully Diluted, Utilizing Independent Engineering, Escalated Pricing

	2016 (1) (2) (3)	2015	2014	2013	2012	2011	2010	2009	2008	2007
PV 0%	$53.12	$60.55	$75.33	$75.69	$68.39	$71.39	$71.38	$72.01	$80.66	$61.03
PV 5%	$34.18	$38.28	$48.62	$51.04	$46.49	$49.81	$47.65	$46.91	$49.30	$40.21
PV 10%	$24.14	$26.49	$34.74	$38.13	$35.11	$38.42	$36.02	$35.08	$34.97	$30.05
PV 15%	$18.05	$19.37	$26.41	$30.25	$28.15	$31.35	$29.10	$28.27	$26.85	$24.04

(1) Based on Sproule's December 31, 2016, escalated price forecast.

(2) Based on 546.9 million shares fully diluted.

(3) Net debt of $3.7 billion as at December 31, 2016.

Reserves Reconciliation

Gross Reserves (1) (2) (3)

	Tight Oil (Mbbls)			Light and Medium Oil (Mbbls)			Heavy Oil (Mbbls)		
Factors	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2015	295,222	178,066	473,288	164,127	99,230	263,356	24,492	8,356	32,847
Extensions and Improved Recovery	27,351	22,887	50,238	8,199	6,067	14,266	-	-	-
Technical Revisions	5,491	(19,347)	(13,856)	6,640	(5,837)	803	797	(1,047)	(251)
Acquisitions	6,005	4,724	10,729	5,803	4,232	10,035	-	-	-
Dispositions	(5)	(2)	(7)	(2,092)	(1,061)	(3,154)	(74)	(21)	(95)
Economic Factors	(6,043)	(1,515)	(7,558)	(5,999)	(2,597)	(8,596)	(530)	42	(489)
Production	(29,494)	-	(29,494)	(17,379)	-	(17,379)	(1,868)	-	(1,868)
December 31, 2016	298,527	184,814	483,341	159,298	100,034	259,331	22,816	7,329	30,145

	Natural Gas Liquids (Mbbls)			Shale Gas (MMcf)			Conventional Natural Gas (MMcf)		
Factors	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2015	54,109	28,646	82,755	191,365	107,277	298,642	133,278	68,532	201,810
Extensions and Improved Recovery	3,551	3,395	6,946	14,854	11,328	26,182	2,405	3,254	5,659
Technical Revisions	6,399	(170)	6,229	63,044	19,501	82,546	15,579	1,348	16,927
Acquisitions	289	245	534	7,082	2,096	9,178	125	32	157
Dispositions	(101)	(58)	(159)	(4)	(2)	(6)	(6,195)	(3,545)	(9,741)
Economic Factors	(791)	(343)	(1,134)	(4,246)	(1,249)	(5,494)	(4,708)	(2,180)	(6,889)
Production	(6,358)	-	(6,358)	(24,594)	-	(24,594)	(13,222)	-	(13,222)
December 31, 2016	57,099	31,714	88,813	247,501	138,953	386,455	127,261	67,441	194,702

	Total Oil Equivalent (Mboe)		
Factors	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2015	592,056	343,599	935,656
Extensions and Improved Recovery	41,978	34,779	76,757
Technical Revisions	32,430	(22,926)	9,505
Acquisitions	13,297	9,556	22,853
Dispositions	(3,305)	(1,734)	(5,039)
Economic Factors	(14,856)	(4,985)	(19,841)
Production	(61,402)	-	(61,402)
December 31, 2016	600,199	358,289	958,489

(1) Based on Sproule's December 31, 2016, escalated price forecast.

(2) "Gross reserves" are the Company's working-interest share before deduction of any royalties and without including any royalty interests of the Company.

(3) Numbers may not add due to rounding.

Finding, Development and Acquisition Costs

	F&D	Change in FDC on F&D	F&D Total (incl. change in FDC)	FD&A (1)	Change in FDC on FD&A	FD&A Total (incl. change in FDC) (1)
Capital ($ millions) (2)						
Total Proved plus Probable	1,138.9	(672.5)	466.4	1,365.4	(449.8)	915.6
Total Proved	1,138.9	(480.6)	658.3	1,365.4	(359.0)	1,006.4
Reserves (Mboe) (3)						
Total Proved plus Probable	66,421	-	66,421	84,235	-	84,235
Total Proved	59,552	-	59,552	69,544	-	69,544

(1) FD&A is calculated by dividing the identified capital expenditures including acquisition costs by the applicable reserves additions. FD&A can include or exclude changes to future development capital costs.

(2) The capital expenditures include the announced purchase price of corporate acquisitions rather than the amounts allocated to property, plant and equipment for accounting purposes. The capital expenditures also exclude capitalized administration costs and transaction costs.

(3) Gross Company interest reserves are used in this calculation (working interest reserves, before deduction of any royalties and without including any royalty interests of the Company).

	Excluding changes in FDC ($/boe, except recycle ratios)			Including changes in FDC ($/boe, except recycle ratios)		
	2016	2015	3 Years Ended Dec. 31, 2016 (Weighted Avg.)	2016	2015	3 Years Ended Dec. 31, 2016 (Weighted Avg.)
F&D Cost (1)						
Total Proved plus Probable	$17.15	$24.01	$20.99	$7.02	$9.83	$14.29
Total Proved	$19.12	$31.10	$24.75	$11.05	$13.97	$17.75
F&D Recycle Ratio (1) (2)						
Total Proved plus Probable	1.3	1.1	1.5	3.2	2.6	2.3
Total Proved	1.2	0.8	1.3	2.0	1.8	1.8
FD&A Cost						
Total Proved plus Probable	$16.21	$18.27	$19.48	$10.87	$18.77	$20.04
Total Proved	$19.63	$27.78	$26.78	$14.47	$24.57	$25.36
FD&A Recycle Ratio (2)						
Total Proved plus Probable	1.4	1.4	1.7	2.0	1.4	1.6
Total Proved	1.1	0.9	1.2	1.5	1.0	1.3

(1) F&D is calculated by dividing the identified capital expenditures by the applicable reserves additions. F&D can include or exclude changes to future development capital costs.

(2) Recycle Ratio is calculated as netback before hedging divided by F&D or FD&A costs. Based on a 2016 netback before hedging of $22.18 per boe, a 2015 netback before hedging of $25.43 per boe and a three-year weighted average netback before hedging of $32.32 per boe.

Future Development Capital

At year-end 2016, FDC for 2P reserves totaled $6.5 billion compared to $7.0 billion at year-end 2015. Net of acquisitions, FDC at year-end 2016 declined $672.5 million reflecting the Company’s efficiency improvements and cost reduction initiatives.

Company Annual Capital Expenditures ($ millions)

	Canada		US		Total	
Year	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
2017	733	965	119	212	852	1,177
2018	902	1,169	366	504	1,268	1,673
2019	636	1,083	315	443	951	1,526
2020	450	797	223	366	673	1,163
2021	74	652	71	156	145	808
2022	6	8	73	99	79	107
2023	6	5	-	-	6	5
2024	5	5	-	-	5	5
2025	5	5	-	-	5	5
2026	4	4	-	-	4	4
2027	3	4	-	-	3	4
2028	3	4	-	-	3	4
Subtotal (1)	2,828	4,703	1,167	1,780	3,996	6,483
Remainder	51	54	-	-	51	54
Total (1)	2,879	4,758	1,167	1,780	4,046	6,537
10% Discounted	2,376	3,808	929	1,411	3,305	5,219

(1) Numbers may not add due to rounding.

CONFERENCE CALL DETAILS

Crescent Point management will host a conference call on Thursday, February 23, 2017 at 10:00 a.m. MT (12:00 p.m. ET), to discuss the results and outlook for the Company.

Participants can access the conference call by dialing 844-231-0101 or 216-562-0389. Alternatively, to listen to this event online, please enter http://edge.media-server.com/m/p/h3yp45wz into any web browser.

For those unable to participate in the conference call at the scheduled time, it will be archived for replay. The replay can be accessed by dialing 855-859-2056 or 404-537-3406 and entering the passcode 51969423. The replay will be available approximately one hour following completion of the call. The webcast will be archived on Crescent Point’s website at www.crescentpointenergy.com.

Shareholders and investors can also find Crescent Point's most recent investor presentation on the Company's website.

2017 GUIDANCE

The Company’s guidance for 2017 is as follows:

Production	
Oil and NGLs (bbls/d)	153,000
Natural gas (mcf/d)	114,000
Total average annual production (boe/d)	172,000
Exit production (boe/d)	183,000
Capital expenditures (1)	
Drilling and development ($ millions)	$1,290
Facilities and seismic ($ millions)	$160
Total ($ millions)	$1,450

(1) The projection of capital expenditures excludes property and land acquisitions, which are separately considered and evaluated.

ON BEHALF OF THE BOARD OF DIRECTORS

Scott Saxberg
President and Chief Executive Officer
February 23, 2017

FINANCIAL AND OPERATING HIGHLIGHTS

(Cdn$ millions except per share and per boe amounts)	Three months ended December 31 **2016**	2015	Year ended December 31 **2016**	2015
Financial				
Cash flow from operating activities	**438.5**	519.5	**1,524.3**	1,956.9
Funds flow from operations (1)	**422.0**	496.7	**1,572.5**	1,938.0
Per share (2)	**0.77**	0.98	**3.03**	4.04
Net income (loss)	**(510.6)**	(382.4)	**(932.7)**	(870.2)
Per share (2)	**(0.94)**	(0.76)	**(1.81)**	(1.82)
Adjusted net earnings from operations (1)	**100.6**	258.0	**88.5**	342.0
Per share (1) (2)	**0.18**	0.51	**0.17**	0.71
Dividends declared	**49.2**	152.8	**260.3**	1,020.4
Per share (2)	**0.09**	0.30	**0.50**	2.11
Payout ratio (%) (1)	**12**	31	**17**	53
Net debt (1)	**3,673.4**	4,263.6	**3,673.4**	4,263.6
Net debt to funds flow from operations (1) (3)	**2.3**	2.2	**2.3**	2.2
Decommissioning and environmental expenditures (4)	**10.0**	8.0	**26.8**	27.1
Weighted average shares outstanding				
Basic	**541.7**	504.9	**516.3**	478.3
Diluted	**544.5**	505.8	**519.3**	479.8
Operating				
Average daily production				
Crude oil (bbls/d)	**130,386**	142,750	**133,172**	137,003
NGLs (bbls/d)	**18,083**	15,253	**17,372**	10,773
Natural gas (mcf/d)	**99,765**	108,631	**103,321**	95,127
Total (boe/d)	**165,097**	176,108	**167,764**	163,631
Average selling prices (5)				
Crude oil ($/bbl)	**56.92**	48.16	**48.46**	52.68
NGLs ($/bbl)	**22.02**	15.54	**15.31**	16.29
Natural gas ($/mcf)	**3.23**	2.58	**2.36**	2.93
Total ($/boe)	**49.32**	41.98	**41.50**	46.88
Netback ($/boe)				
Oil and gas sales	**49.32**	41.98	**41.50**	46.88
Royalties	**(7.33)**	(6.38)	**(5.93)**	(7.30)
Operating expenses	**(11.89)**	(10.95)	**(11.27)**	(11.83)
Transportation expenses	**(2.09)**	(2.17)	**(2.12)**	(2.32)
Netback before hedging	**28.01**	22.48	**22.18**	25.43
Realized gain on derivatives	**3.47**	11.69	**7.63**	10.76
Netback (1)	**31.48**	34.17	**29.81**	36.19
Capital Expenditures				
Capital acquisitions (net) (6)	**9.8**	20.8	**226.5**	1,760.4
Development capital expenditures (4)				
Drilling and development	**350.5**	298.3	**950.6**	1,352.9
Facilities and seismic	**41.8**	47.4	**145.8**	171.1
Land	**18.4**	9.1	**42.5**	37.8
Total	**410.7**	354.8	**1,138.9**	1,561.8

(1) Funds flow from operations, adjusted net earnings from operations, payout ratio, net debt, net debt to funds flow from operations and netback as presented do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities.
(2) The per share amounts (with the exception of dividends per share) are the per share – diluted amounts.
(3) Net debt to funds flow from operations is calculated as the period end net debt divided by the sum of funds flow from operations for the trailing four quarters.
(4) Decommissioning and environmental expenditures includes environmental emission reduction expenditures, which are also included in development capital expenditures in the table above.
(5) The average selling prices reported are before realized derivatives.
(6) Capital acquisitions represent total consideration for the transactions, including long-term debt and working capital assumed, and exclude transaction costs.

This news release contains forward-looking information and references to non-GAAP financial measures. Significant related assumptions and risk factors, and reconciliations are described under the Non-GAAP Financial Measures and the Forward-Looking Statements and Reserves Data sections of this news release, respectively.

Non-GAAP Financial Measures

Throughout this press release, the Company uses the terms "funds flow from operations", "funds flow from operations per share - diluted", "adjusted net earnings from operations", "adjusted net earnings from operations per share - diluted", "net debt", "net debt to funds flow from operations", "netback", "payout ratio" and "total payout ratio". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Funds flow from operations per share - diluted is calculated as funds flow from operations divided by the number of weighted average diluted shares outstanding. Transaction costs are excluded as they vary based on the Company's acquisition activity and to ensure that this metric is more comparable between periods. Decommissioning expenditures are excluded as the Company has a voluntary reclamation fund to fund decommissioning costs. Management utilizes funds flow from operations as a key measure to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow from operating activities to funds flow from operations:

	Three months ended December 31		Year ended December 31	
($ millions)	**2016**	2015	**2016**	2015
Cash flow from operating activities	**438.5**	519.5	**1,524.3**	1,956.9
Changes in non-cash working capital	**(23.5)**	(30.6)	**29.9**	(48.9)
Transaction costs	**0.5**	3.0	**2.3**	14.2
Decommissioning expenditures	**6.5**	4.8	**16.0**	15.8
Funds flow from operations	**422.0**	496.7	**1,572.5**	1,938.0

Adjusted net earnings from operations is calculated based on net income before amortization of exploration and evaluation ("E&E") undeveloped land, impairment or impairment recoveries on property, plant and equipment ("PP&E"), unrealized derivative gains or losses, unrealized foreign exchange gain or loss on translation of hedged US dollar long-term debt, unrealized gains or losses on long-term investments and gains or losses on capital acquisitions and dispositions. Adjusted net earnings from operations per share - diluted is calculated as adjusted net earnings from operations divided by the number of weighted average diluted shares outstanding. Management utilizes adjusted net earnings from operations to present a measure of financial performance that is more comparable between periods. Adjusted net earnings from operations as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles net income to adjusted net earnings from operations:

	Three months ended December 31		Year ended December 31	
($ millions)	**2016**	2015	**2016**	2015
Net income (loss)	**(510.6)**	(382.4)	**(932.7)**	(870.2)
Amortization of E&E undeveloped land	**29.2**	57.0	**172.5**	205.9
Impairment to PP&E	**611.4**	829.6	**611.4**	1,385.3
Unrealized derivative (gains) losses	**138.7**	(97.5)	**706.8**	(228.1)
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**44.1**	98.6	**(110.6)**	346.2
Unrealized (gain) loss on long-term investments	**0.5**	5.2	**(5.5)**	13.9
(Gain) loss on capital acquisitions / dispositions	**-**	-	**15.3**	(18.8)
Deferred tax relating to adjustments	**(212.7)**	(252.5)	**(368.7)**	(492.2)
Adjusted net earnings from operations	**100.6**	258.0	**88.5**	342.0

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities and dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the unrealized foreign exchange on translation of hedged US dollar long-term debt. Management utilizes net debt as a key measure to assess the liquidity of the Company.

The following table reconciles long-term debt to net debt:

($ millions)	**2016**	2015
Long-term debt [1]	**3,820.7**	4,452.0
Accounts payable and accrued liabilities	**647.2**	679.4
Dividends payable	**16.3**	50.5
Cash	**(13.4)**	(24.7)
Accounts receivable	**(335.7)**	(327.0)
Prepaids and deposits	**(5.3)**	(5.1)
Long-term investments	**(35.8)**	(30.3)
Excludes:		
Unrealized foreign exchange on translation of hedged US dollar long-term debt	**(420.6)**	(531.2)
Net debt	**3,673.4**	4,263.6

(1) Includes current portion of long-term debt.

Net debt to funds flow from operations is calculated as the period end net debt divided by the sum of funds flow from operations for the trailing four quarters. The ratio of net debt to funds flow from operations is used by management to measure the Company's overall debt position and to measure the strength of the Company's balance sheet. Crescent Point monitors this ratio and uses this as a key measure in making decisions regarding financing, capital spending and dividend levels.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is a common metric used in the oil and gas industry and is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. The calculation of netback is shown in the Financial and Operating Highlights section in this press release.

Payout ratio is calculated on a percentage basis as dividends declared divided by funds flow from operations. Payout ratio is used by management to monitor the dividend policy and the amount of funds flow from operations retained by the Company for capital reinvestment.

Total payout ratio is calculated on a percentage basis as development capital expenditures and declared divided by funds flow from operations. Total payout ratio is used by management to monitor the Company's capital reinvestment and dividend policy, as a percentage of the amount of funds flow from operations.

Management believes the presentation of the Non-GAAP measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Definitions

Decline rate is the reduction in the rate of production from one period to the next. This rate is usually expressed on an annual basis.

Finding and development costs (F&D) is calculated by dividing the identified capital expenditures by the applicable reserves additions. F&D can include or exclude changes to future development capital costs.

Finding, development and acquisitions costs (FD&A) is calculated by dividing the identified capital expenditures including acquisition costs by the applicable reserves additions. FD&A can include or exclude changes to future development capital costs.

Future development capital (FDC) reflects the independent evaluator's best estimate of the cost required to bring proved undeveloped and probable reserves on production. Changes in FDC can result from acquisition and disposition activities, development plans or changes in capital efficiencies due to inflation or reductions in service costs and/or improvements to drilling and completion methods.

Net asset value (NAV) is a snapshot in time as at year-end, and is based on the Company's reserves evaluated using the independent evaluators forecast for future prices, costs and foreign exchange rates. The Company's NAV is calculated on a before tax basis and is the sum of the present value of proved and probable reserves, the fair value for land and seismic, the fair value for the Company's oil and gas hedges based on Sproule's December 31, 2016 escalated price forecast, less outstanding net debt. The NAV per share is calculated on a fully diluted basis.

N1 51-101 means "*National Instrument 51-101 - Standards for Disclosure for Oil and Gas Activities*".

Recycle Ratio is calculated as operating netback divided by F&D or FD&A costs. Based on a 2016 netback (before hedging), of $22.18 per boe, a 2015 netback (before hedging) of $25.43 per boe and a three-year weighted average netback (before hedging) of $32.32 per boe.

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. Proved reserves are reserves estimated to have a high degree of certainty of recoverability. Probable reserves are less certain to be recoverable than probable reserves and possible reserves are less certain than probable reserves.

Reserves and Drilling Data

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2016, which will be filed on or before February 23, 2017.

Where applicable, a barrels of oil equivalent ("boe") conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6Mcf:1bbl) has been used based on an energy equivalent conversion method primarily applicable at the burner tip. 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.

This press release contains metrics commonly used in the oil and natural gas industry including "netbacks", "F&D costs", "FD&A costs", "FDC", "NAV", "recycle ratio", "decline rate", and "drilling inventory". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons.

F&D costs, including changes in FDC have been presented in this news release because they provide a useful measure of capital efficiency. F&D costs, including land, facility and seismic expenditures and excluding changes in FDC have also been presented in this news release because they provide a useful measure of capital efficiency.

FD&A costs, including changes in FDC have been presented in this news release because they provide a useful measure of capital efficiency. FD&A costs, including land, facility and seismic expenditures and excluding changes in FDC have also been presented in this news release because they provide a useful measure of capital efficiency.

Management uses recycle ratio for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Drilling inventory is calculated in years as the Company's 2016 year-end inventory divided by the number of wells in its 2017 drilling program. Drilling inventory is used by management to assess the amount of available drilling opportunities.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL 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 oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, NGL 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 prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation. This press release contains estimates of the net present value of the Company's future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) and EDGAR (accessible at www.sec.gov/edgar.shtml) on or before February 23, 2017.

In this press release, the: 1,031 new internally identified drilling locations include 134 booked and 897 unbooked locations, the 8,000 total internally identified corporate drilling inventory includes 3,679 booked and 4,406 unbooked locations, the 120 net horizontal follow-up locations in Castle Peak include 23 booked and 97 unbooked locations, the 700 locations in the Williston Basin include 85 booked and 658 unbooked locations, the 300 net locations acquired in third quarter 2016 include 73 booked and 227 unbooked locations, and the 500 net new drilling locations in southwest Saskatchewan include 30 booked and 530 unbooked locations. These unbooked potential drilling opportunities may include infill, lease-edge and undrilled tracts, based on current land holdings, geologic, geophysical and engineering analysis that result in mapped type-well groupings and optimized scheduling.

Notice to US Readers

The oil and natural gas reserves contained in this press 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), but permits the optional disclosure of "probable reserves" and "possible reserves" (each 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 and permits optional disclosure of "possible reserves", each as defined in NI 51-101. Accordingly, "proved reserves", "probable reserves" and "possible reserves" disclosed in this news release may not be comparable to US standards, and in this news release, Crescent Point has disclosed reserves designated as "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. "Possible reserves" are higher risk than "probable reserves" and are generally believed to be less likely to be accurately estimated or recovered than "probable reserves". 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 SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments. Moreover, Crescent Point has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Consequently, Crescent Point’s reserve estimates and production volumes in this news release may not be comparable to those made by companies using United States reporting and disclosure standards. Further, the SEC rules are based on unescalated costs and forecasts.

All amounts in the news release are stated in Canadian dollars unless otherwise specified.

Forward-Looking Statements

Any "financial outlook" or "future oriented financial information" in this press release, as defined by applicable securities legislation has been approved by management of Crescent Point. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management’s current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Certain statements contained in this press release constitute "forward-looking statements" within the meaning of section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934 and "forward-looking information" for the purposes of Canadian securities regulation (collectively, "forward-looking statements"). The Company has tried to identify such forward-looking statements by use of such words as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "intend", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well-positioned" and other similar expressions, but these words are not the exclusive means of identifying such statements.

In particular, this press release contains forward-looking statements pertaining, among other things, to the following: the Company's focus on organic growth, new play development and improved investor communication in 2017; the Company’s plans to expand on the success of its Castle Peak type well in the Uinta Basin by optimizing its drilling and completions process and drilling horizontal wells in 2017; the Company’s plans to continue to focus on long-term value creation by testing and implementing new technologies, including the installation of its "ICD" systems in the Williston Basin and Southwest Saskatchewan; the Company's estimated total payout ratio in 2017; the nomination of Mr. Ted Goldthorpe as a director of the Company at the Company’s 2017 annual shareholder meeting and the retirement of Mr. Greg Turnbull; the Company's 2017 drilling plans and production estimates; the Company's commitment to advancing its waterflood programs and ICD technology; the Company’s plans to re-visit its production guidance following spring break-up; expected capital cost increases in 2017; expected exit to exit production growth; the Company’s continuing monitoring of service costs within its 2017 drilling program; the Company’s plans to explore additional non-core disposition opportunities within its assets base in 2017 and afterwards; the Company's ongoing commitment to transparency and accountability; continued play development in the Uinta and Williston Basins; 2017 drilling plans for wells in the Williston Basin and in Southwest Saskatchewan; 2017 drilling plans for horizontal wells in Uinta; exit production growth in the Williston and Uinta Basins and in Southwest Saskatchewan; the Company’s continuation of its step-out drilling and down-spacing programs within its Flat Lake and North Dakota resources plays; 2017 plans to extend the boundaries of the Williston Basin through a combination of step-out wells and infill drilling opportunities; continued efforts to reduce overall cost structure through the implementation of new technology and efficiency improvements; the expectation that the closeable sliding sleeves in the Saskatchewan Viking play will result in reduced well clean-out costs similar to those achieved in the Viewfield Bakken and Shaunavon resources plays; the Company’s plans to test extended reach horizontals in an effort to enhance and improve the economic development of the Viking resources play; plans to continue to delineate the Uinta resource play for future horizontal development beyond the Castle Peak zone; plans to continue to test new waterflood technology in both its Williston Basin and Southwest Saskatchewan waterflood programs during 2017; the Company’s expectation to have production results from newly installed "ICD" systems by the second half of 2017; the expectation that using the "ICD" technology will allow existing injectors to become candidates for additional injector conversions without the need to take existing producing wells offline; annual average production expectations for 2017; preliminary 2017 production and capital expenditure budget and related growth rate; and the Company’s ongoing commitment to maintain a strong financial position while continuing to maximize shareholder return through a total return strategy of long-term growth plus dividend income.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

Unless otherwise noted, reserves referenced herein are given as at December 31, 2016. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties due to the effect of aggregation. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2016, which is accessible at www.sedar.com.

With respect to disclosure contained herein regarding resources other than reserves, there is uncertainty that it will be commercially viable to produce any portion of the resources and there is significant uncertainty regarding the ultimate recoverability of such resources.

All forward-looking statements are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. Crescent Point believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this report should not be unduly relied upon. By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in the Company's Annual Information Form for the year ended December 31, 2016 under "*Risk Factors"* and our Management's Discussion and Analysis for the year ended December 31, 2016, under the headings "*Risk Factors"* and "*Forward-Looking Information"*. The material assumptions are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2016, under the headings "*Capital Expenditures"*, "*Liquidity and Capital Resources"*, "*Critical Accounting Estimates"*, "*Risk Factors*", "*Changes in Accounting Policies"* and "*Outlook"*. In addition, risk factors include: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions, blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations and the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; risks and uncertainties related to all oil and gas interests and operations on tribal lands; uncertainties associated with estimating oil and natural gas reserves; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of Crescent Point. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Crescent Point's future course of action depends on management's assessment of all information available at the relevant time.

Additional information on these and other factors that could affect Crescent Point's operations or financial results are included in Crescent Point's reports on file with Canadian and U.S. securities regulatory authorities. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed herein or otherwise. Crescent Point undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required to do so pursuant to applicable law. All subsequent forward-looking statements, whether written or oral, attributable to Crescent Point or persons acting on the Company's behalf are expressly qualified in their entirety by these cautionary statements.

FOR MORE INFORMATION ON CRESCENT POINT ENERGY, PLEASE CONTACT:

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Crescent Point shares are traded on the Toronto Stock Exchange and New York Stock Exchange, both under the symbol CPG.

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