International Petroleum Corp.

Operations and Financial Update
Year End 2018

Mike Nicholson, CEO
Christophe Nerguararian, CFO
February 12, 2019

International Petroleum Corp.
2018 Highlights

Production Guidance	- Full year average production exceeds high case CMD guidance at **34,400** boepd
Operating Costs[1]	- Operating costs of **12.4** USD/boe, below 2018 guidance of **12.6** USD/boe
Organic Growth	- Capital expenditure of **39** MUSD (revised guidance 44 MUSD)
Operating Cash Flow[1]	- Operating cash flow of **279** MUSD - Net debt down from **355 to 166** MUSD since Suffield acquisition (January 5, 2018)[1,3] - Year end net debt **277** MUSD[4]
Reserves and Resources[2]	- **>100%** reserves replacement ratio excluding acquisitions - **Reserves increase** across all countries - **>2x** increase to **288** MMboe of 2P reserves and **>1.1 billion** boe of 2P+2C resources
Acquisition & Divestment	- Highly value accretive acquisition of BlackPearl completed - Disposal of Netherlands assets completed -> 25 MUSD gain on sale
HSE	- No material incidents

1) Non-IFRS measure, see Reader Advisory and MD&A
2) As at December 31, 2018, see Reader Advisory and MCR
3) Excluding net debt acquired as part of BlackPearl acquisition
4) Including net debt acquired as part of BlackPearl acquisition

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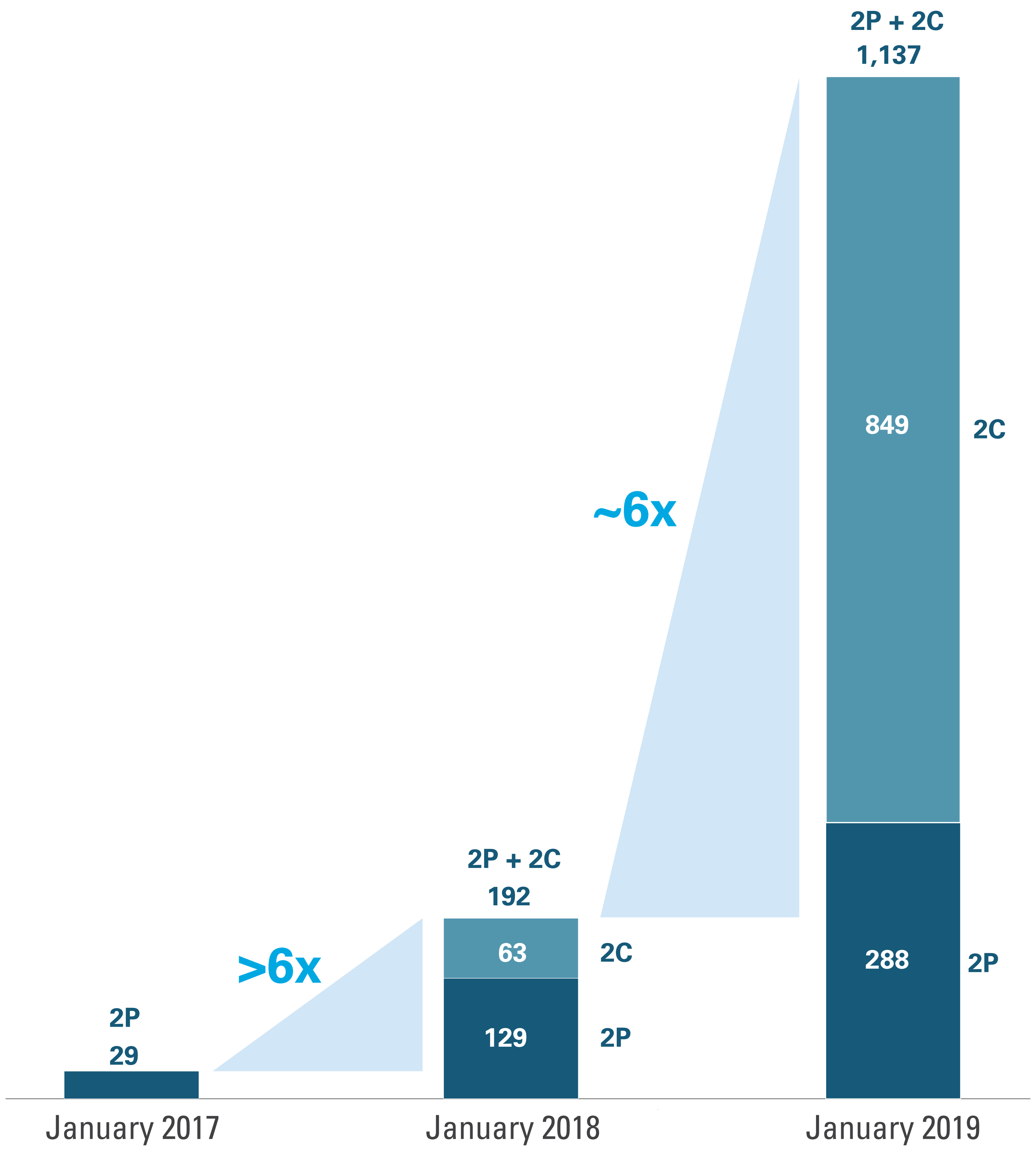
Resource Growth

- **>100% reserves replacement in 2018**
- **More than doubled 2P reserves to 288 MMboe [1]**
- **Increased reserves life index (RLI) from 11 to 16 years [1]**
- **More than 13x increase in Contingent Resource base [1]**

Net Reserves and Contingent Resources >1.1 bn boe

Net Reserves and Contingent Resources (MMboe)



[1] As at December 31, 2018. See Reader Advisory and MCR

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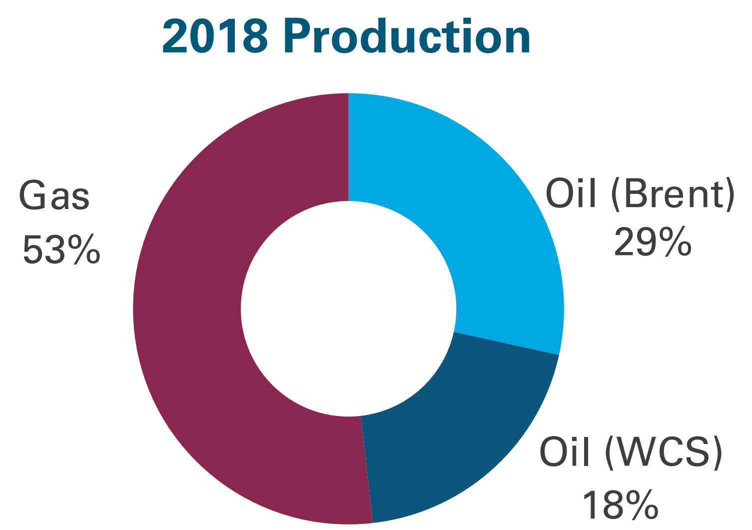
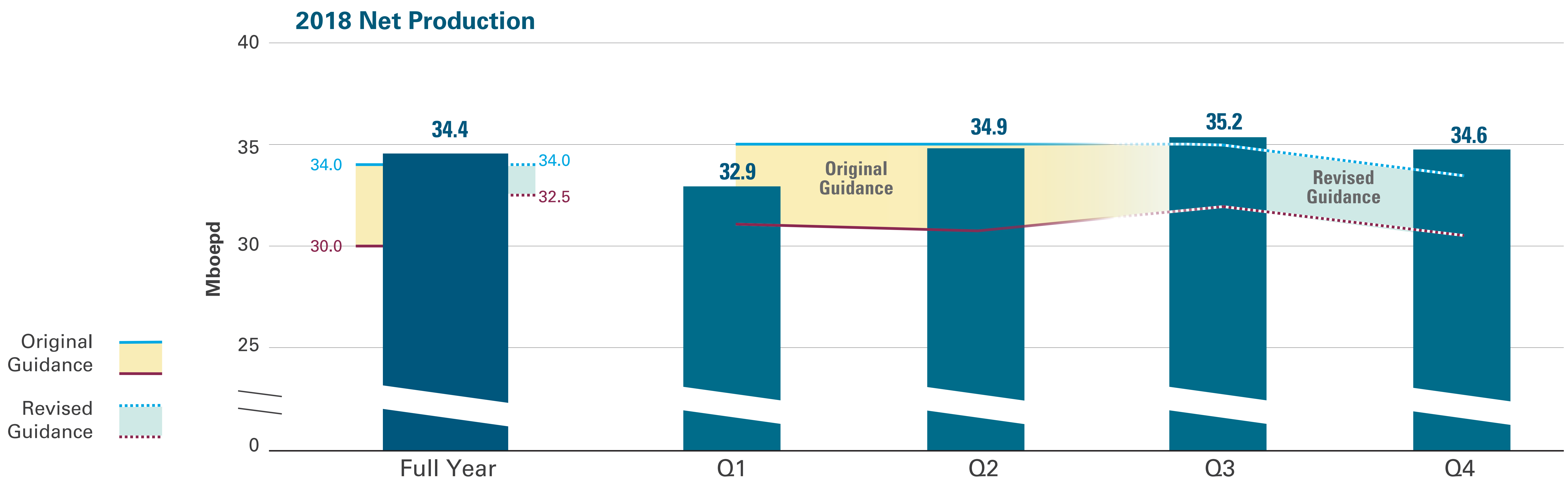
International Petroleum Corp.
2018 Production

- **Production above CMD high case at 34,400 boepd**
  - Bertam infill well performance
  - Canada gas optimisation results

  } Ahead of expectation
- **2018 operating cost per boe below guidance at 12.4 USD/boe [1] (CMD guidance 12.6 USD/boe)**
- **HSE -> No major incidents in 2018**





[1] *Non-IFRS measure, see Reader Advisory and MD&A*

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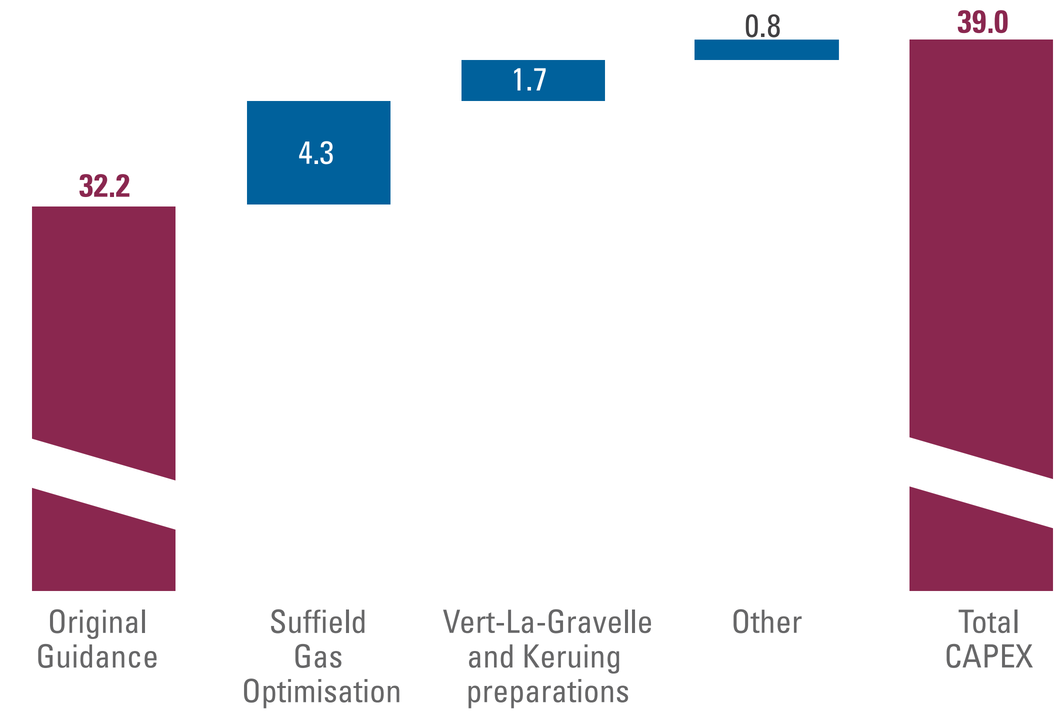
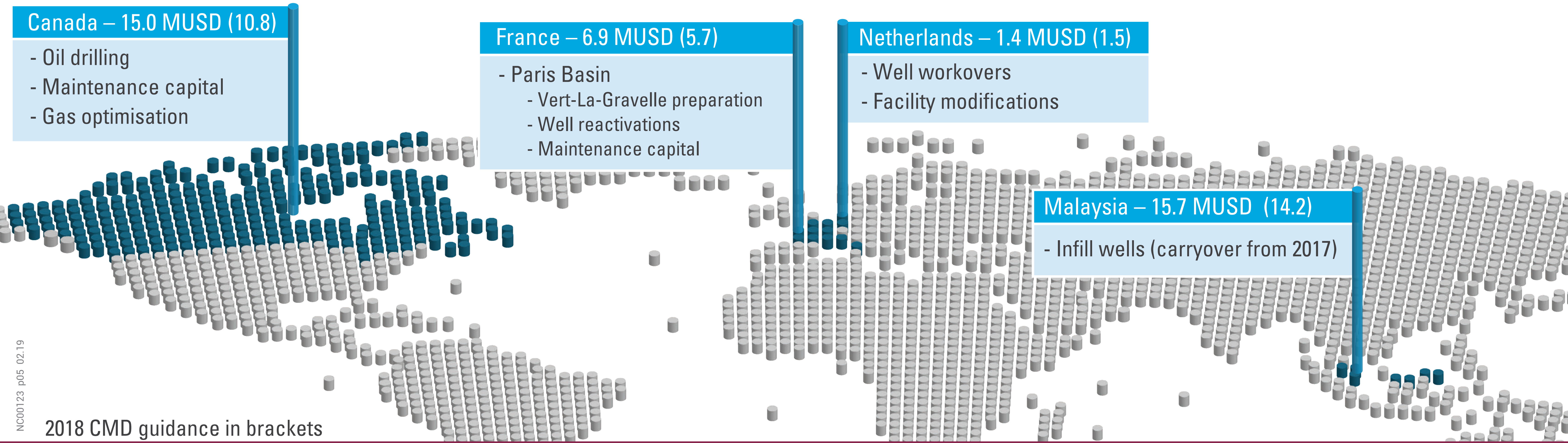
2018 Net Capital Expenditure

- **2018 capital expenditure: 39 MUSD (original guidance 32 MUSD)**
  - Additional organic growth sanctioned during 2018
- **Successful capital programme executed in 2018**
  - Malaysia: A16 and A17 infills
  - Canada: oil drilling and gas optimisation
  - France: preparations for 2019 activity

CAPEX Movements 2018





2018 CMD guidance in brackets

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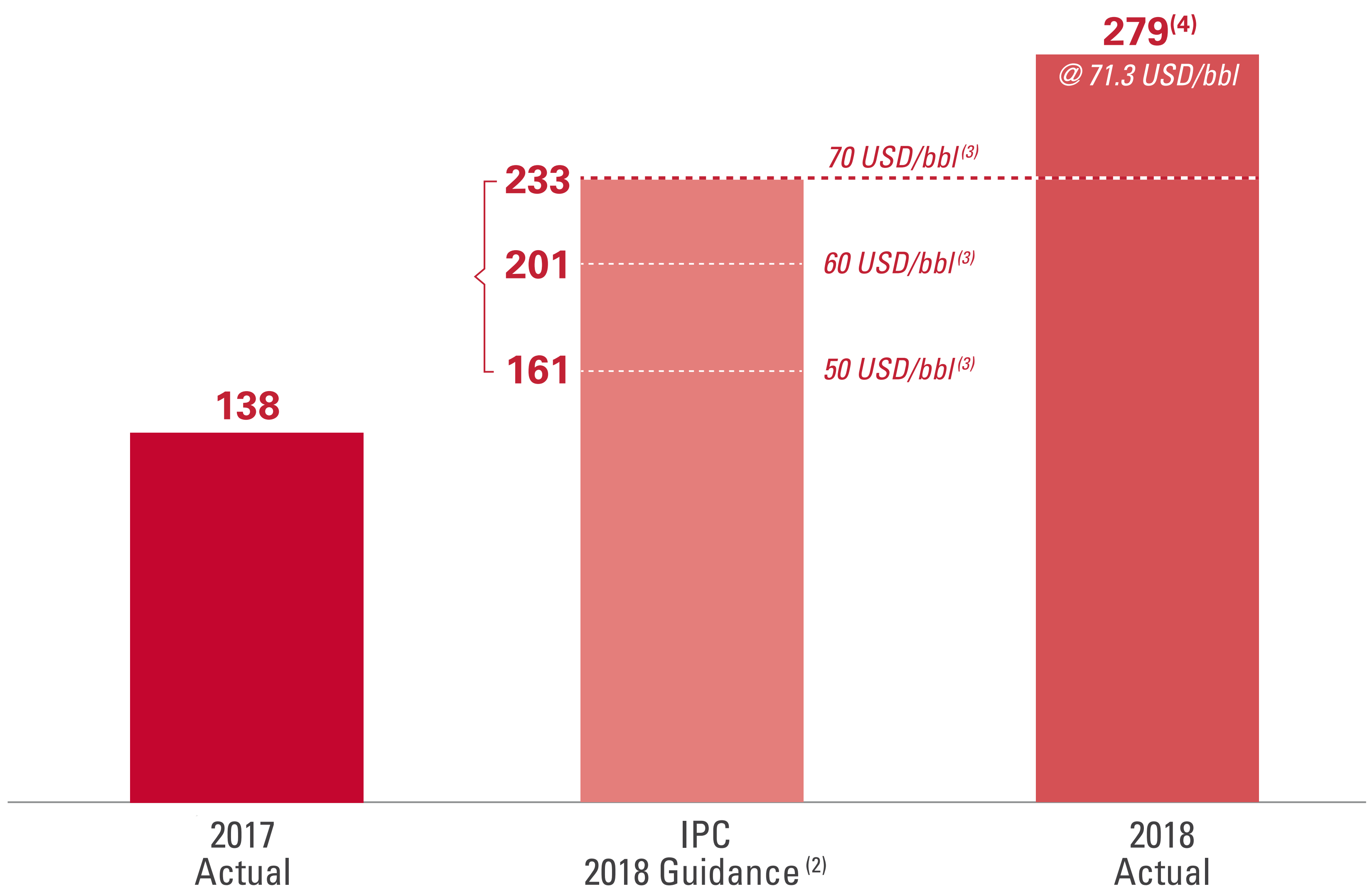
Operating Cash Flow [1]

- 2018 operating cash flow of 279 MUSD => 20% ahead of full year 2018 guidance
- Net Debt [1] end 2018 reduced by >50% to 166 MUSD since Suffield acquisition completion; 277 MUSD including BlackPearl



[1] Non-IFRS measure, see MD&A

[2] Based upon original 2018 mid-point production guidance

[3] Brent oil price assumptions

[4] Including OCF related to Netherlands assets disposed in December 2018

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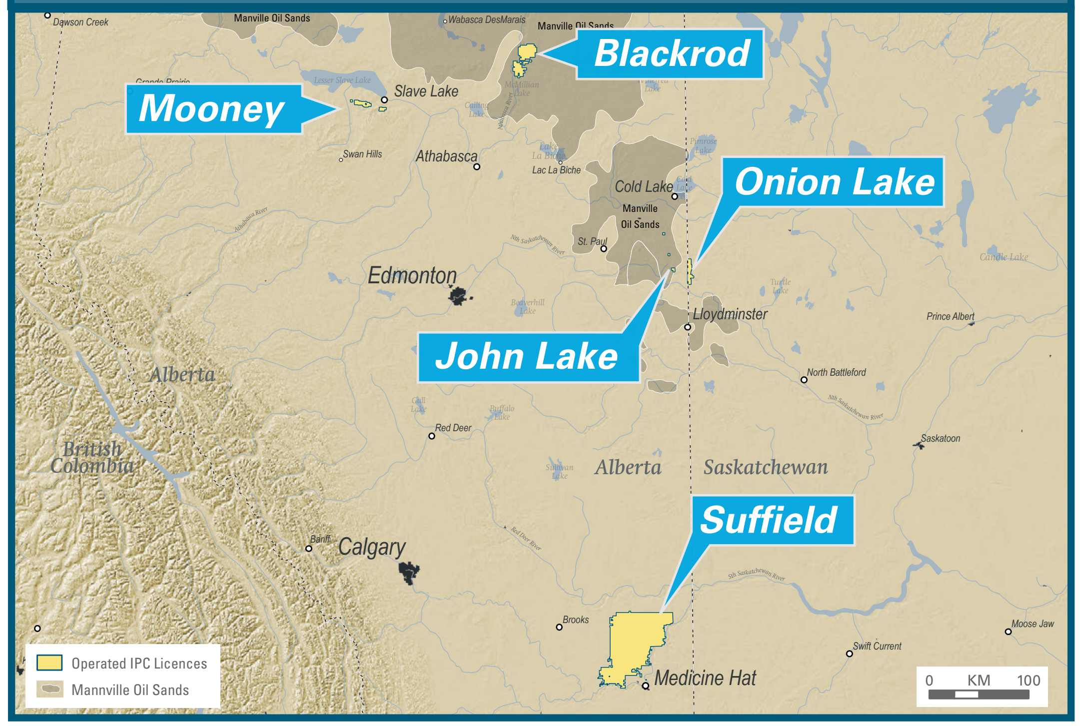
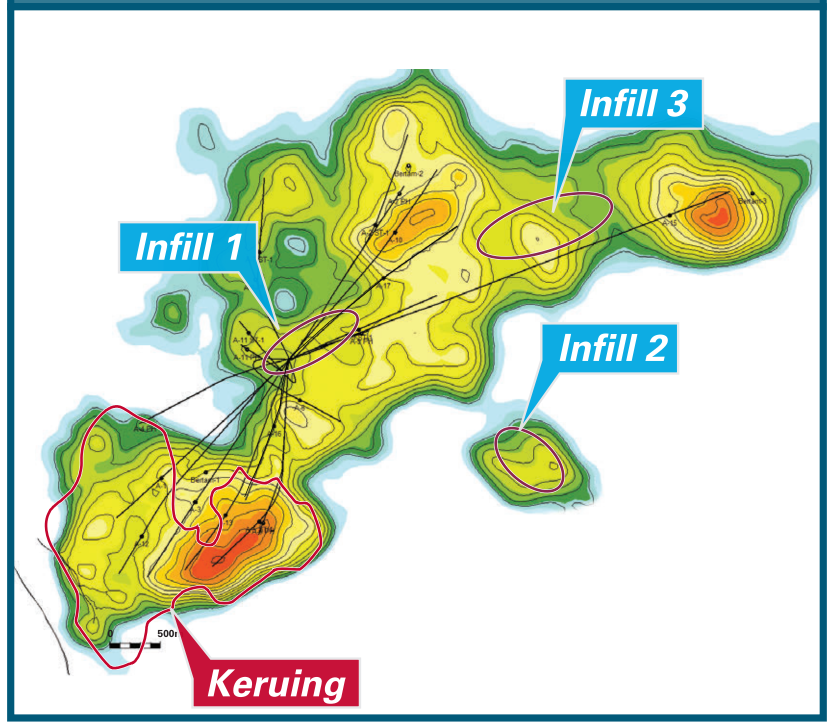
Organic Growth Opportunities in 2019

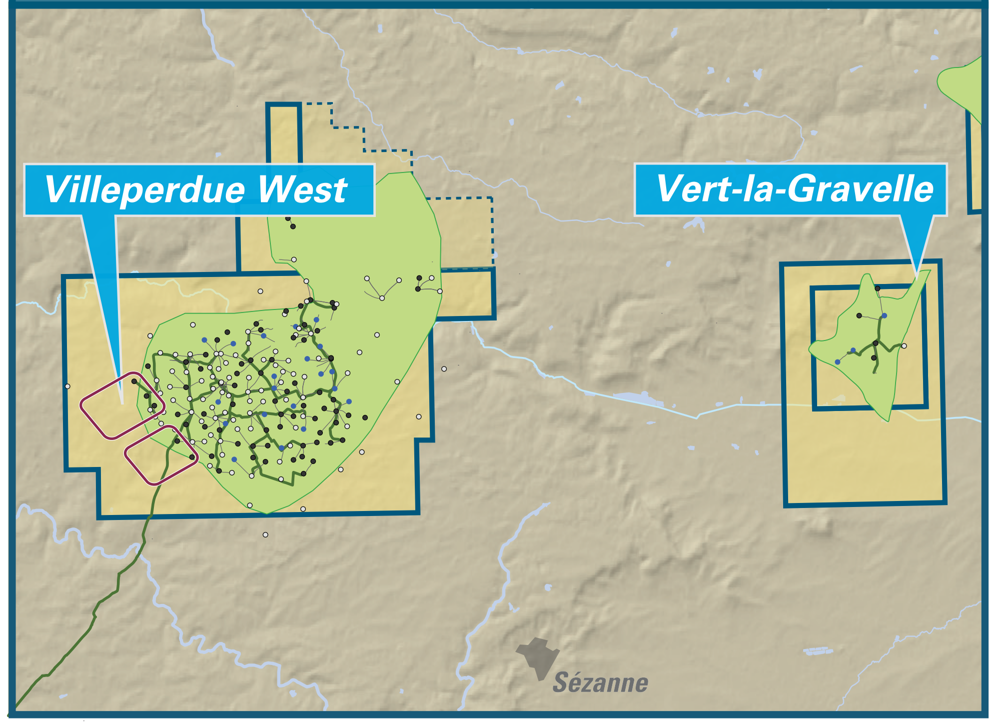
Canada



Malaysia – Bertam



France – Paris Basin



- **Canada**
  - Suffield
    - Continue oil drilling -> Matured 20+ locations
    - Mature N2N EOR project to final investment decision
  - Onion Lake expansion
    - Additional conventional drilling
    - Additional steam generation capacity
    - Additional sustaining wells

- **Malaysia**
  - Keruing exploration well
  - Drill up to 3 infill wells
  - Seek to identify additional infill targets

- **France**
  - Vert-La-Gravelle drilling
  - Mature Villeperdue West development

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Year End 2018 Financial Highlights

Year End 2018

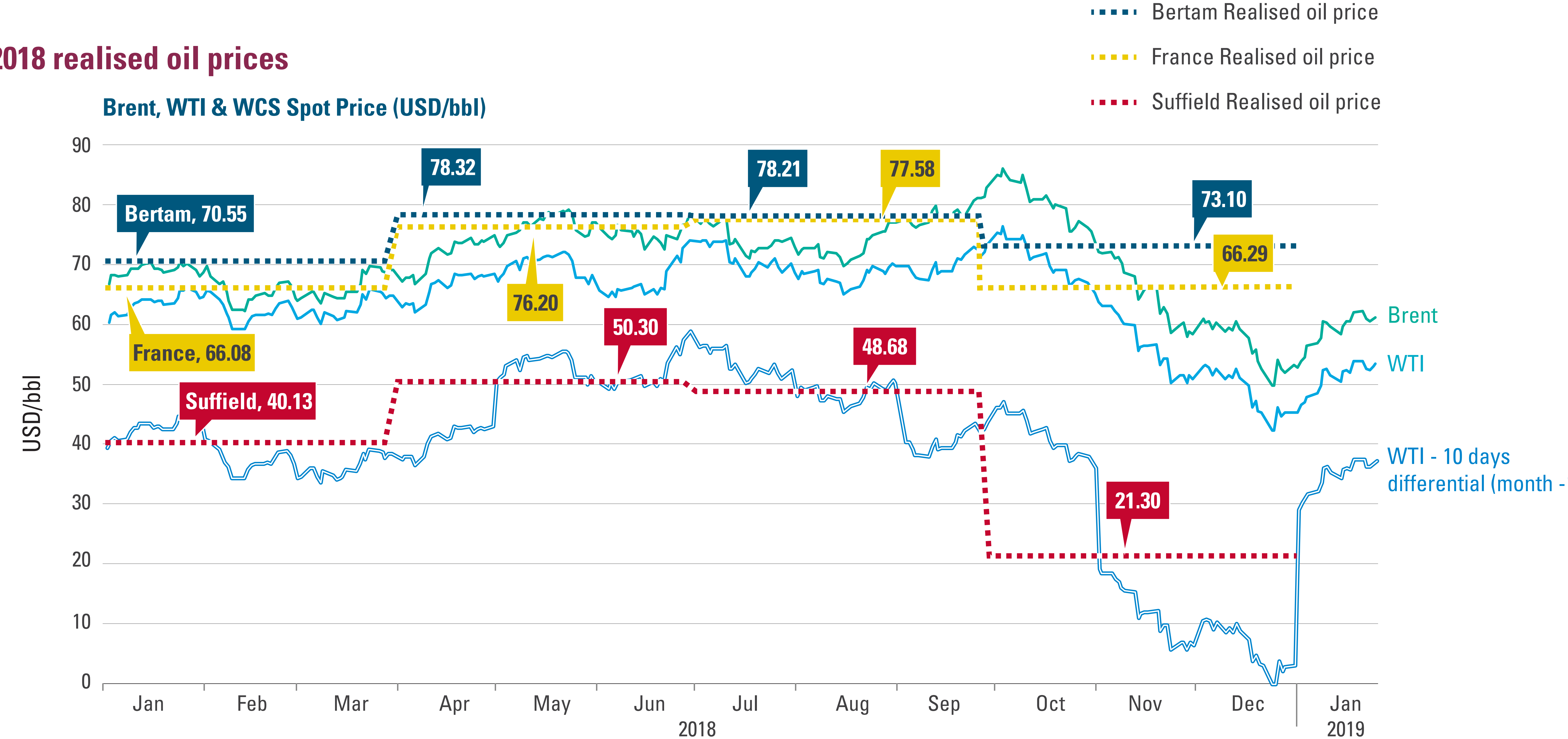
Financial Highlights

	Fourth Quarter 2018	Full Year 2018
Production (boepd)	34,600	34,400
Average Dated Brent Oil Price (USD/boe)	68.8	71.3
Operating costs (USD/boe) [1]	13.1	12.4
Operating cash flow (MUSD) [1]	58.3	279.0
EBITDA (MUSD) [1]	58.0	264.0
Net result (MUSD)	29.3	103.6

[1] *Non-IFRS Measure, see MD&A*

Year End 2018
Realised Oil Prices

▪ 2018 realised oil prices



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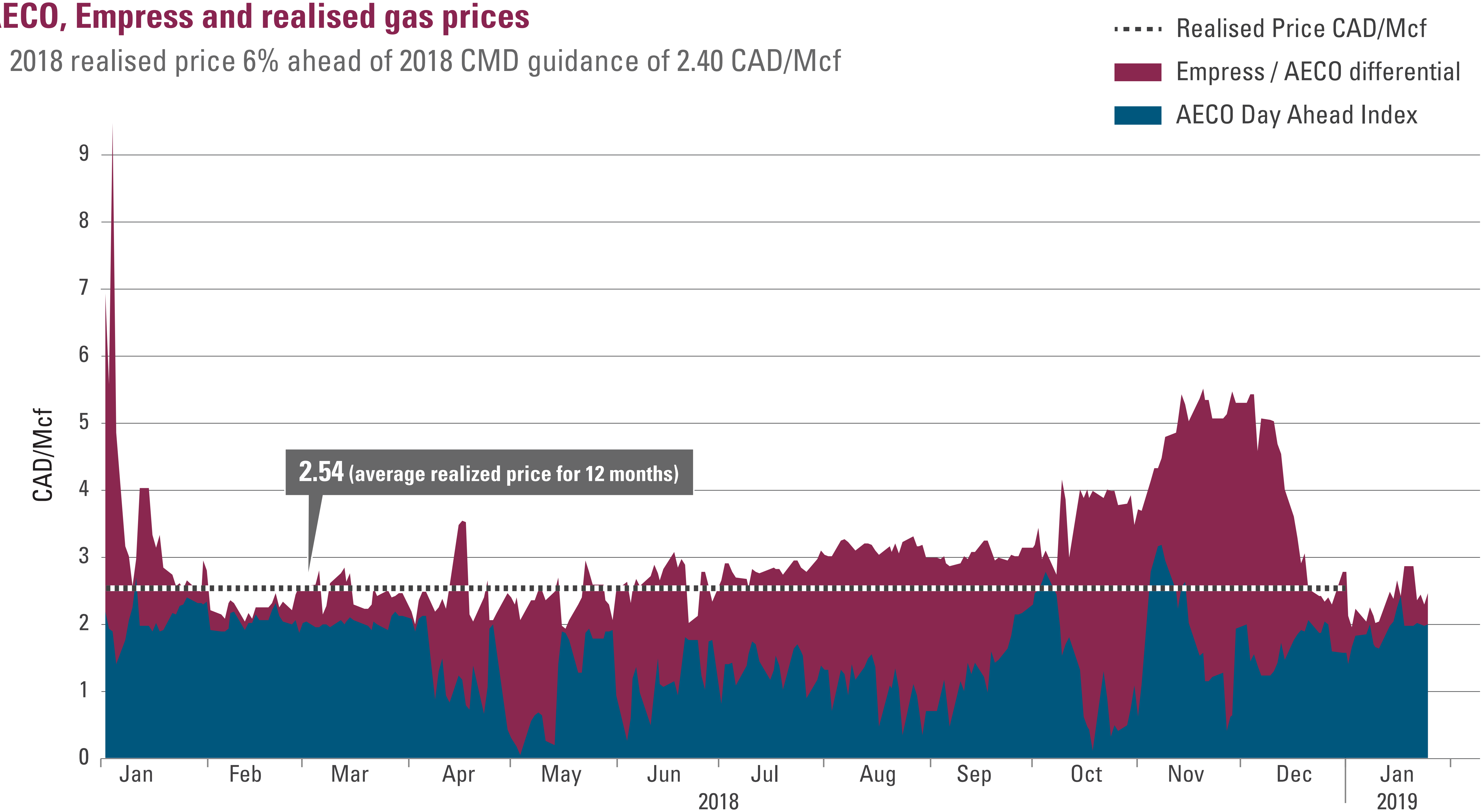
Year End 2018
Realised Gas Prices

- **AECO, Empress and realised gas prices**
  - 2018 realised price 6% ahead of 2018 CMD guidance of 2.40 CAD/Mcf



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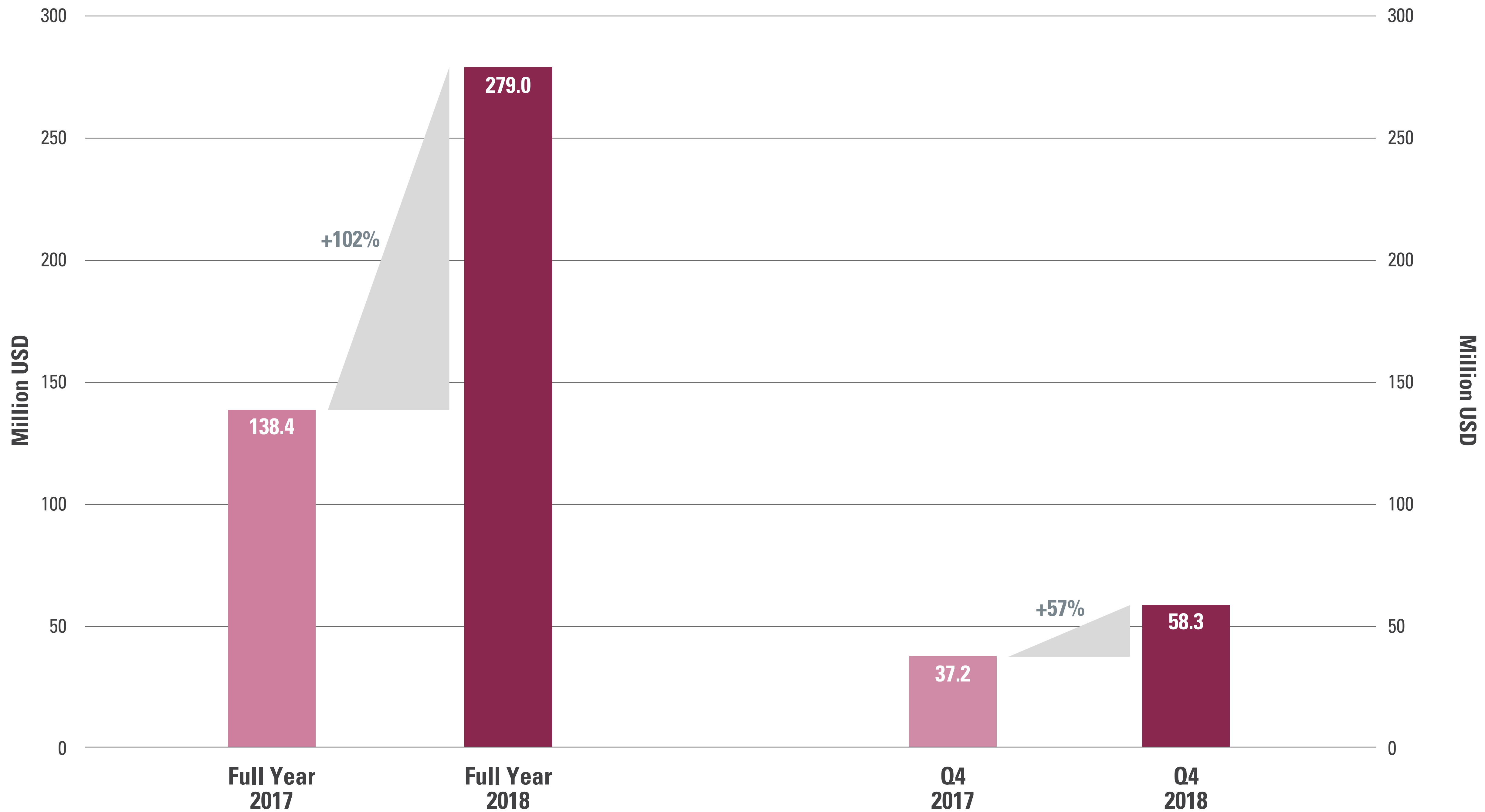
Year End 2018

Financial Results – Operating Cash Flow [1]



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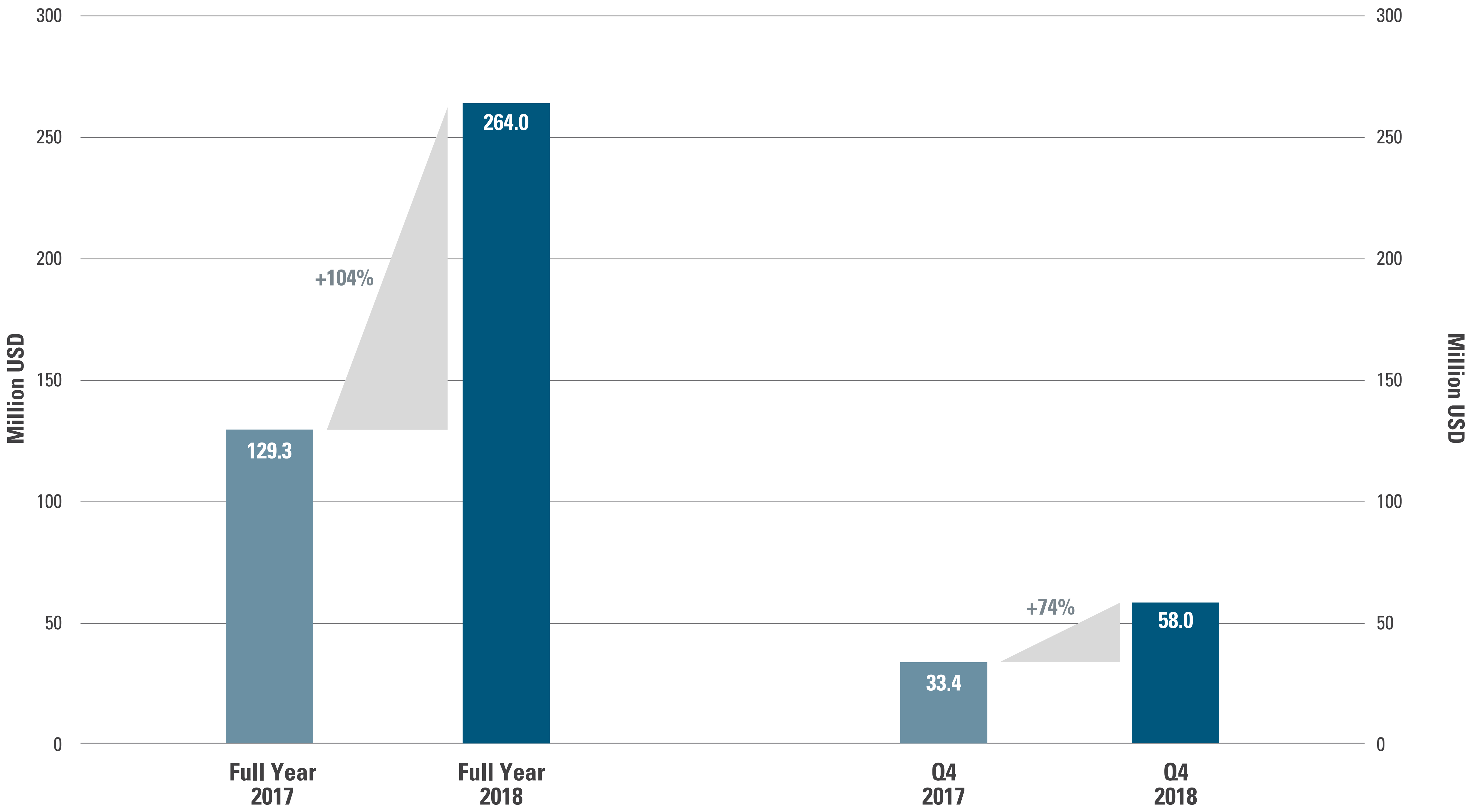
(1) *Non-IFRS Measure, see MD&A*

Year End 2018

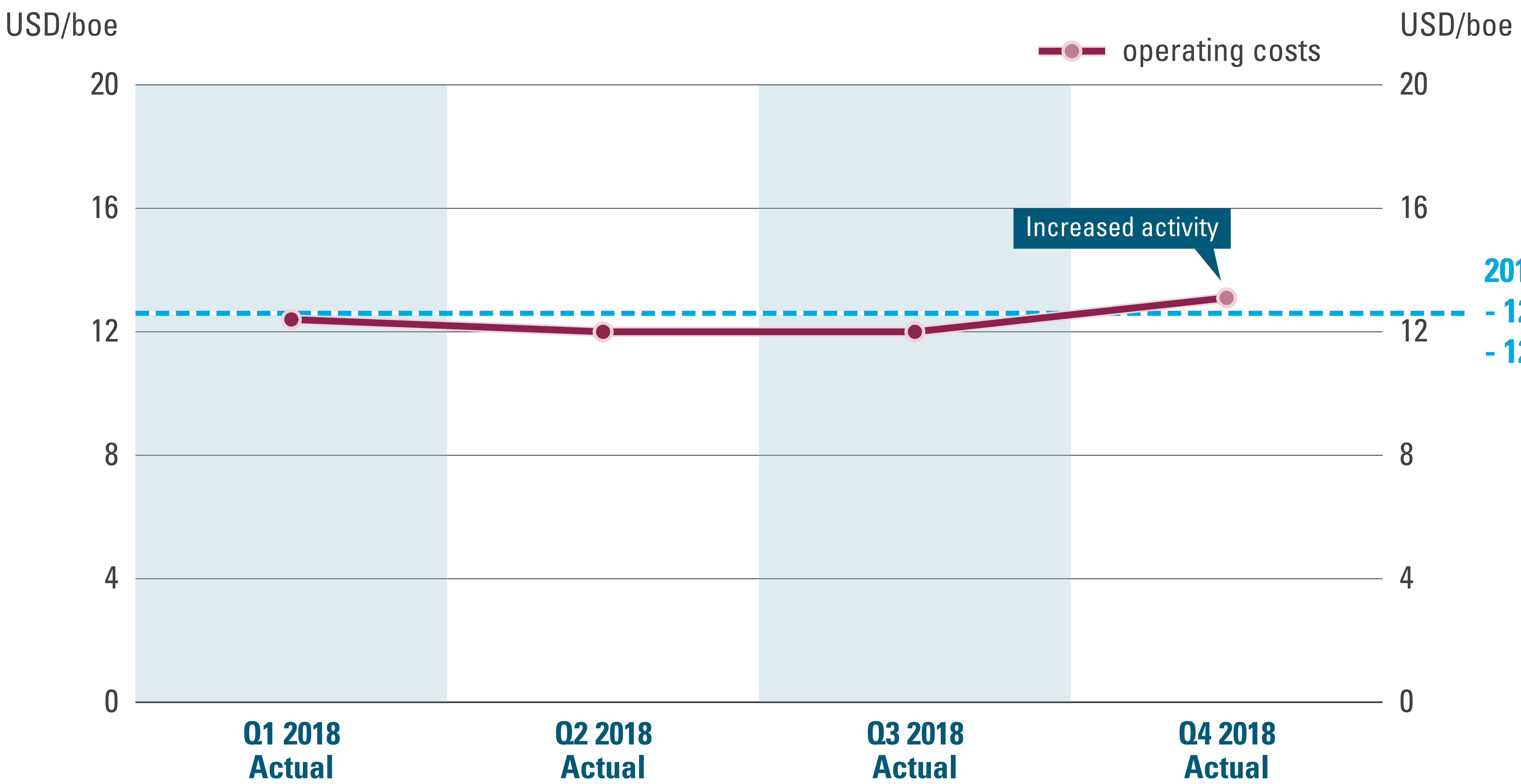
Financial Results – EBITDA [1]



(1) *Non-IFRS Measure, see MD&A*

Year End 2018

Operating Costs [1]



2018 Operating Costs:
- 12.6 USD/boe guidance
- 12.4 USD/boe actual

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[1] *Non-IFRS Measure, see MD&A*

Year End 2018

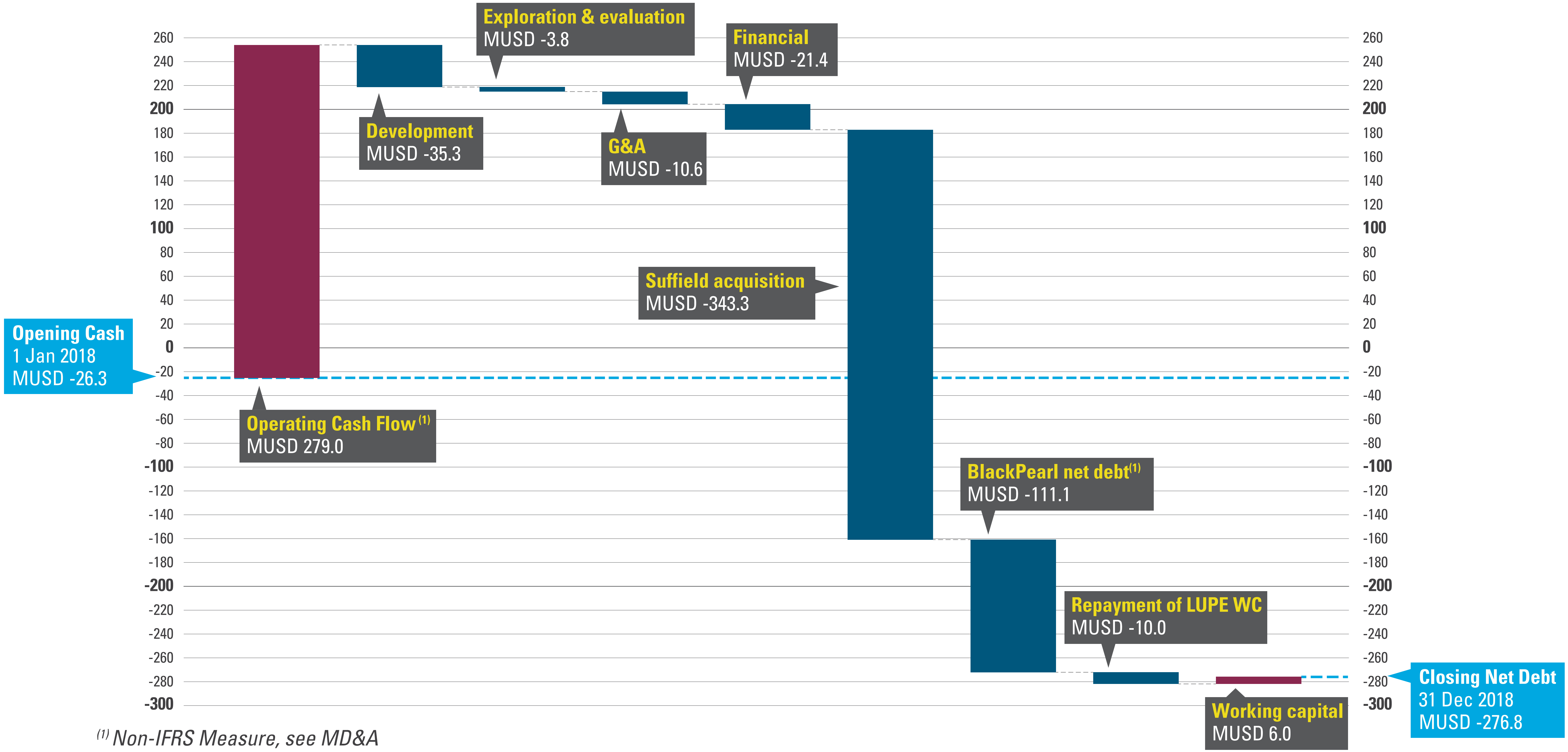
Netback [1] (USD/boe)

	Fourth Quarter 2018	Full Year 2018
Average Dated Brent oil price	*(68.8 USD/bbl)*	*(71.3 USD/bbl)*
Revenue	35.1	36.2
Cost of operations	-11.1	-10.4
Tariff and transportation	-1.4	-1.4
Production taxes	-0.6	-0.6
Operating costs [2]	-13.1	-12.4
Cost of blending	-1.5	-2.0
Inventory movements	-2.0	–
Revenue – production costs	**18.5**	**21.8**
Cash taxes	-0.2	0.4
Operating cash flow [2]	**18.3**	**22.2**
General and administration costs [3]	-0.3	-0.8
EBITDA [2]	**18.2**	**21.0**

[1] Based on production volumes *[2] Non-IFRS Measure, see MD&A* *[3] Adjusted for depreciation*

Year End 2018

Cash Flows and Closing Net Debt[1] (MUSD)



[1] *Non-IFRS Measure, see MD&A*

Year End 2018

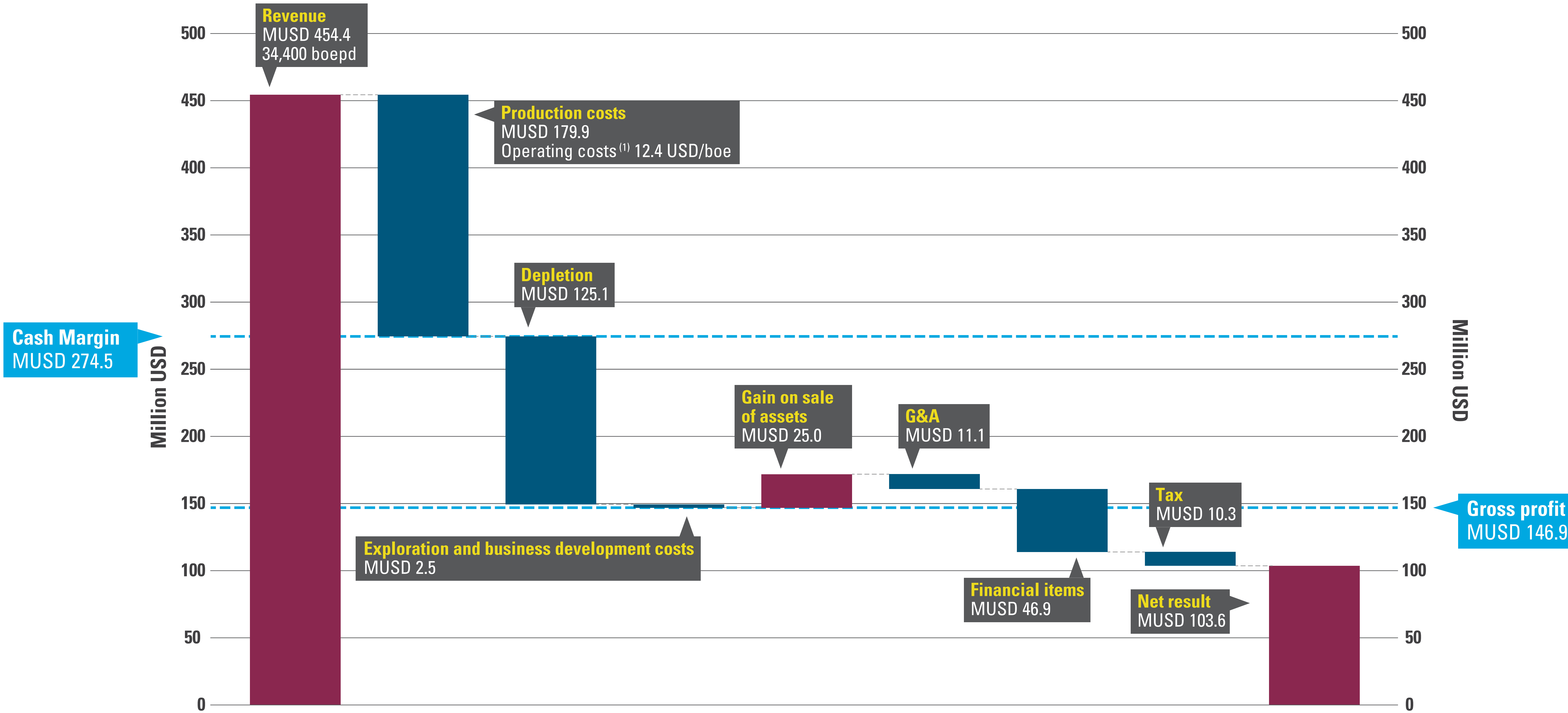
G&A / Financial Items

MUSD	Fourth Quarter 2018	Full Year 2018
G&A	1.1	10.6
G&A – Depreciation	0.1	0.5
G&A Expense	**1.2**	**11.1**

	Fourth Quarter 2018	Full Year 2018
Interest expense	2.9	14.7
Loan facility commitment fees	0.4	1.0
Amortisation of loan fees	0.7	3.2
Foreign exchange loss (gain), net [1]	11.1	17.3
Unwinding of asset retirement obligation	2.2	9.2
Other	2.1	1.5
Net Finance Costs	**19.4**	**46.9**

[1] *Mainly non-cash, driven by the revaluation of external and intra-group loans*

Year End 2018
Financial Results



[1] *Non-IFRS Measure, see MD&A*

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Year End 2018
Balance Sheet

MUSD	31 Dec 2018	31 Dec 2017
Assets		
Oil and gas properties	1,014.8	319.8
Other non-current assets	169.4	135.4
Current assets	98.9	134.5
	1,283.1	**589.7**
Liabilities		
Financial liabilities	283.7	59.3
Provisions	151.5	105.9
Other non-current liabilities	55.8	53.9
Current liabilities	96.3	63.7
Equity	695.8	306.9
	1,283.1	**589.7**

Year End 2018

Liquidity and Hedging

- **Credit Facilities**
  - One International (200 MUSD) and two Canadian (200 and 120 MCAD) revolving credit facilities
  - Second lien notes (75 MCAD)
  - In excess of 150 MUSD availability under revolving credit lines

- **Hedging**
  - 20 to 50% of former Blackpearl production volumes
  - Up to 18 months maturity
  - Mostly using collars

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Reader Advisory

Forward Looking Statements
This presentation contains statements and information which constitute “forward-looking statements” or “forward-looking information” (within the meaning of applicable securities legislation). Such statements and information (together, “forward-looking statements”) relate to future events, including the Corporation’s future performance, business prospects or opportunities. Actual results may differ materially from those expressed or implied by forward-looking statements. The forward-looking statements contained in this presentation are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this presentation, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as “seek”, “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “forecast”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe”, “budget” and similar expressions) are not statements of historical fact and may be “forward-looking statements”. Forward-looking statements include, but are not limited to, statements with respect to: : IPC’s intention and ability to continue to implement our strategies to build long-term shareholder value; IPC’s intention to review future potential growth opportunities; the ability of IPC’s portfolio of assets to provide a solid foundation for organic and inorganic growth; the continued facility uptime and reservoir performance in IPC’s areas of operation; the proposed Vert La Gravelle development project and other organic growth opportunities in France, including the Villeperdue West project; the proposed third phase of infill drilling in Malaysia and the ability to mature additional locations; the drilling of the Keruing prospect in Malaysia and the development options if drilling is successful; future development potential of the Suffield area operations, including continued and future oil drilling and gas optimization programs; the state of the oil markets, including in Canada following the curtailments announced by the Alberta government in 2018; future development of the Blackrod project in Canada; the results of the facility optimization program and the work to debottleneck the facilities and injection capability at Onion Lake Thermal; the ability to integrate the assets and operations acquired in the BlackPearl acquisition, including the ability to accelerate value creation and extend IPC’s reserves life following such acquisition; 2019 production range, exit rate, operating costs and capital expenditure; potential further acquisition opportunities; estimates of reserves; estimates of contingent resources; estimates of prospective resources; the ability to generate free cash flows and use that cash to repay debt and to continue to deleverage; and future drilling and other exploration and development activities.

Statements relating to “reserves”; “contingent resources” and “prospective resources” are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successfully.

Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; the ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; and changes in legislation, including but not limited to tax laws, royalties and environmental regulations. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the material change report dated February 12, 2019 (MCR), the management discussion and analysis for the three months ended and the year ended December 31, 2018 (MD&A) (See “Cautionary Statement Regarding Forward-Looking Information” therein), the Corporation’s Annual Information Form (AIF) for the year ended December 31, 2017 (See “Cautionary Statement Regarding Forward-Looking Information”, “Reserves and Resources Advisory” and “ Risk Factors” therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC’s website (www.international-petroleum.com).

Non-IFRS Measures
References are made in this press release to “operating cash flow” (OCF), “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt”/”net cash”, which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

Management believes that OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Corporation’s ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Corporation’s operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of issuers.

The definition and reconciliation of each non-IFRS measure is presented in IPC’s MD&A (See “Non-IFRS Measures” therein).

Disclosure of Oil and Gas Information
This presentation contains references to estimates of 2P reserves and resources attributed to the Corporation’s oil and gas assets. Gross reserves / resources are the total working interest (operating or non-operating) share reserves before the deduction of any royalties and without including any royalty interests receivable.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Suffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel’s January 1, 2019 price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Onion Lake, Blackrod and Mooney areas of Canada are effective as of December 31, 2018, and are included in the report prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel’s January 1, 2019 price forecasts.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France and Malaysia are effective as of December 31, 2018, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel’s January 1, 2019 price forecasts.

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The price forecasts used in the reserve reports are available on the website of McDaniel (www.mcdan.com), and are contained in the MCR.

The reserves life index (RLI) is calculated by dividing the 2P reserves of 288 MMboe as at December 31, 2018, by the mid-point of the initial 2019 production guidance of 46,000 to 50,000 boepd. The reserves replacement ratio is based on 2P reserves of 129.1 MMboe as at December 31, 2017 (including the 2P reserves attributable to the acquisition of the Suffield area assets which completed on January 5, 2018), production during 2018 of 12.4 MMboe, additions to 2P reserves during 2018 of 12.7 MMboe and 2P reserves of 128.0 MMboe as at December 31, 2018 (excluding the 2P reserves attributable to the acquisition of BlackPearl which completed on December 14, 2018).

“2P reserves” means IPC’s gross proved plus probable reserves. “Proved reserves” are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. “Probable reserves” 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.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on a project maturity and/or characterized by their economic status.

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation’s contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified 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. Chance of development is the probability of a project being commercially viable.

References to “unrisked” contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

The contingent resources reported in this presentation are estimates only. The estimates are based upon a number of factors and assumptions each of which contains estimation error which could result in future revisions of the estimates as more technical and commercial information becomes available. The estimation factors include, but are not limited to, the mapped extent of the oil and gas accumulations, geologic characteristics of the reservoirs, and dynamic reservoir performance. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Corporation’s control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in this presentation.

2P reserves and contingent resources included in the reports of McDaniel, Sproule and ERCE have been aggregated in this presentation by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This presentation contains estimates of the net present value of the future net revenue from IPC’s reserves. The estimated values of future net revenue disclosed in this presentation do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves”. References to “prospective resources” do not constitute, and should be distinguished from, references to “contingent resources” and “reserves”.

This presentation includes oil and gas metrics including “cash margin netback”, “taxation netback”, “operating cash flow netback”, “cash taxes”, “EBITDA netback” and “profit netback”. Such metrics do not have a standardized meaning under IFRS or otherwise, and as such may not be reliable. This information should not be used to make comparisons.

“Cash margin netback” is calculated on a per boe basis as oil and gas sales, less operating, tariff/transportation and production tax expenses. 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.

“Taxation netback” is calculated on a per boe basis as current tax charge/credit less deferred tax charge/credit. Taxation netback is used to measure taxation on a per boe basis.

“Operating cash flow netback” is calculated as cash margin netback less cash taxes. Operating cash flow netback is used to measure operating results on a per boe basis of cash flow.

“Cash taxes” is calculated as taxes payable in cash, and not only for accounting purposes. Cash taxes is used to measure cash flow.

“EBITDA netback” is calculated as cash margin netback less general and administration expenses. EBITDA netback is used by management to measure operating results on a per boe basis.

“Profit netback” is calculated as cash margin netback less depletion/depreciation, general and administration expenses and financial items. Profit netback is used by management to measure operating results on a per boe basis.

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Currency
All dollar amounts in this presentation are expressed in United States dollars, except where otherwise noted. References herein to USD mean United States dollars. References herein to CAD mean Canadian dollars.

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