PRESS RELEASE

MEG Energy announces full year 2019 free cash flow of $528 million, debt repayment of $501 million and 18% year over year reduction in G&A expense

All financial figures are in Canadian dollars ($ or C$) and all references to barrels are per barrel of bitumen sales unless otherwise noted

CALGARY, ALBERTA (March 4th, 2020) – MEG Energy Corp. (TSX:MEG, "MEG" or the "Corporation") reported its full year 2019 operational and financial results.

Highlights include:

- Free cash flow of $528 million driven by adjusted funds flow of $726 million ($2.41 per share) and disciplined capital spend of $198 million;
- Bitumen production volumes of 93,082 barrels per day (bbls/d) at a steam-oil-ratio (SOR) of 2.22;
- Net operating costs of $5.24 per barrel, supported by record low non-energy operating costs of $4.61 per barrel and strong power sales which had the impact of offsetting 74% of per barrel energy operating costs resulting in a net energy operating cost of $0.63 per barrel;
- Average AWB blend sales price net of transportation and storage costs at Edmonton of US$42.20 per barrel which was better than the posted 2019 AWB index price of US$42.08 per barrel, notwithstanding 43% Enbridge mainline apportionment, highlighting the value of MEG's North American marketing strategy;
- General and administrative expense of $68 million which was $15 million, or 18%, lower than 2018;
- During 2019 MEG amended and restated its existing credit facilities to have new 5-year terms and repaid $501 million of outstanding long-term debt. Cash cost savings expected from the reduction in credit fees and interest savings on debt repaid in 2019 are $45 million annually; and
- Subsequent to year end, MEG utilized cash-on-hand to repay an additional $132 million of long-term debt concurrent with the refinancing of US$1.2 billion of existing indebtedness. The combination of these transactions is neutral to ongoing cash costs.

"As we entered 2019, we stated that we would continue to improve overall cost efficiencies, preserve financial liquidity and enhance MEG's competitive position" says Derek Evans, President and Chief Executive Officer. "Since making that commitment to shareholders MEG has repaid $633 million of long-term debt, entered into a new modified-covenant-lite 5-year credit facility, refinanced US$1.2 billion of existing indebtedness, significantly reduced ongoing G&A expense and posted record low annual non-energy operating costs. We remain committed to driving efficiencies in our business from a financial, operational and cost perspective and will continue to direct all available free cash flow to debt repayment."

Financial Liquidity and Debt Repayment

Maintaining long term financial liquidity while aggressively pursuing ongoing debt repayment remains MEG's top priority.

Since the beginning of 2019 the Corporation has repaid $633 million (US$479 million) of long-term debt including $501 million (US$379 million) of long-term debt in 2019 and an additional $132 million (US$100 million) subsequent to year end. This was accomplished through the repayment of the senior secured term loan balance of $297 million (US$225 million) and the repurchase and extinguishment of $336 million (US$254 million) aggregate principal amount of 6.5% senior secured second lien notes.

Additionally, in July 2019 the Corporation entered into a new 5-year revolving credit facility and letter of credit facility. The total borrowing capacity available under the two facilities was proactively reduced to $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under the letter of credit facility. The facilities contain no financial maintenance covenants unless MEG has drawn in excess of $400 million under the revolving credit facility.

Cash cost savings from the reduction in credit fees and interest savings on debt repaid in 2019 are expected to be $45 million annually.

In January 2020, the Corporation successfully closed a private offering of US$1.2 billion in aggregate principal amount of 7.125% senior unsecured notes due February 2027. The net proceeds of the offering plus cash-on-hand were used to fully redeem US$800 million of the 6.375% senior unsecured notes due January 2023 and partially redeem US$400 million of the US$1.0 billion 7.0% senior unsecured notes due March 2024. Post this refinancing, MEG has a 4-year runway until its next debt maturity represented by the remaining US$600 million of March 2024 notes.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$46.19 per barrel in 2019 compared to US$41.25 per barrel in 2018. The average WTI price decreased US$7.74 per barrel year over year, but this was more than offset by the US$15.04 per barrel narrowing of the average WTI:AWB differential at Edmonton. Also contributing to the realized AWB blend sales price in 2019 was the Corporation's ability to deliver 33% of its blend sales volumes to the U.S. Gulf Coast ("USGC"), where the WTI:AWB differential averaged US$1.77 per barrel. Comparatively, in 2018 the Corporation delivered 30% of its blend sales volumes to the USGC when the average WTI:AWB differential was US$6.68 per barrel.

Transportation and storage costs averaged US$5.70 per barrel of AWB blend sales in 2019 compared to US$4.51 per barrel of AWB blend sales in 2018. The higher costs in 2019 reflect the increased use of rail transportation. In 2019, 15% of total blend sales volumes were transported by rail compared to 6% of total blend sales volumes transported by rail in 2018. Also contributing to the increased costs in 2019 was the sale of the Access Pipeline that occurred in March 2018, which increased transportation costs from that point forward.

Excluding transportation and storage costs upstream of the Edmonton index sales point, MEG's net AWB blend sales price at Edmonton averaged US$42.20 per barrel in 2019 compared to the posted AWB index price at Edmonton of US$42.08. Notwithstanding that Enbridge mainline apportionment averaged 43% during 2019, MEG was able to capture pricing better than the Edmonton index as a result of its marketing and storage assets and the ability to move barrels to the higher-priced USGC market. MEG's average pricing against the AWB index price at Edmonton is expected to improve further once MEG's contracted capacity on the Flanagan and Seaway pipeline system doubles to 100,000 bbls/d of blend in mid-2020.

MEG's AWB blend sales by rail in 2019 were 19,686 bbls/d compared to 7,857 bbls/d in 2018 as the Corporation ramped up rail utilization beginning in the fourth quarter of 2018 as Edmonton WTI:AWB differentials supported increased rail usage. 42% of sales by rail in 2019 were delivered to the USGC compared to 52% in 2018, with the remainder sold at Edmonton.

Operational Performance

Bitumen production averaged 94,566 bbls/d in the fourth quarter of 2019, contributing to a 6% increase in annual production in 2019 of 93,082 bbls/d compared to 87,731 bbls/d in 2018. The annual increase is primarily due to the impact of turnaround activities in 2018. Production in 2019 was impacted by curtailment limits imposed by the Government of Alberta, which the Corporation was partially able to mitigate through third-party curtailment credits, allowing MEG to produce at levels above its government-mandated limits.

Annual net operating costs in 2019 averaged $5.24 per barrel, a 3% increase compared to 2018, directly impacted by higher natural gas purchase prices which were partially offset by higher sales of surplus power from MEG's cogeneration facilities. Non-energy operating costs averaged a record low of $4.61 per barrel as the Corporation continues to drive efficiency gains into its operations while maintaining production levels. Net operating costs during the fourth quarter of 2019 were higher than the fourth quarter of 2018 mainly as a result of higher energy costs.

General and administrative ("G&A") expense was $68 million, or $1.99 per barrel of production, in 2019 compared to $83 million, or $2.58 per barrel of production, in 2018. The $15 million decrease in aggregate G&A year over year is primarily due to the reduction of staffing levels and rationalization of ongoing administrative costs.

Adjusted Funds Flow and Net Loss

MEG's bitumen realization averaged $53.21 per barrel in 2019 compared to $36.69 per barrel in 2018. The increase is mainly due to the significant narrowing of the WTI:AWB differential, particularly at Edmonton. The narrowing differential also resulted in a higher recovery of diluent expense through blend sales, which lowered the Corporation's cost of diluent.

The improved bitumen realization resulted in MEG's cash operating netback increasing to $32.15 per barrel in 2019 from $17.61 per barrel in 2018. The higher cash operating netback drove the increase in adjusted funds flow from $180 million in 2018 to $726 million in 2019.

The Corporation realized a net loss of $62 million in 2019 compared to a net loss of $119 million in 2018. The net loss in 2019 was related to various non-cash items including one-time accelerated depreciation charges recognized in the second quarter of 2019 as the Corporation's strategy shifted away from production growth to debt repayment and an unrealized loss on commodity risk management contracts, partially offset by an unrealized foreign exchange gain.

Capital Expenditures

Capital expenditures in 2019 totaled $198 million compared to $622 million in 2018. Capital expenditures in 2019 were primarily directed towards sustaining and maintenance activities, as well as advancing work already underway on the Phase 2B brownfield facility expansion. As previously announced, the expansion includes incremental steam generation, water handling and oil treating capacity, and is expected to be completed in the second quarter of 2020.

Outlook

Announced in November 2019, MEG's capital investment plan for 2020 of $250 million includes $210 million to be directed towards sustaining and maintenance capital and $20 million to be directed towards the completion of the in-progress Phase 2B brownfield expansion expected to be completed in the second quarter of 2020. The remaining $20 million of capital spending is required for non-discretionary field infrastructure, regulatory and corporate capital costs.

The Corporation's 2020 annual average bitumen production volumes are targeted to be in the range of 94,000 - 97,000 bbls/d which includes the impact of a plant turnaround planned for the third quarter of 2020. In response to the Alberta Government's Special Production Allowance ("SPA") program announcement on October 31, 2019 for curtailed producers, the Corporation began ramping up its productive capacity and expects to reach its full 100,000 bbls/d production capacity subsequent to the planned turnaround.

For the first half of 2020, MEG has entered into benchmark WTI fixed price swaps for approximately 70% of forecast first half 2020 production volumes at an average price of US$59.15 per barrel. On a full year basis, MEG has hedged approximately 55% of forecast 2020 production via benchmark WTI fixed price swaps and WTI fixed price swaps with sold put options. Additionally, the Corporation has hedged approximately 30% of its WTI:WCS differential exposure at an average price of (US$19.39) per barrel and approximately 50% of condensate exposure at an average price of 101% of WTI. The table below reflects MEG's current 2020 financial and physical hedge positions.

	Forecast Period				
	Q1 2020	Q2 2020	Q3 2020	Q4 2020	2020
WTI Hedges					
WTI Fixed Price Hedges					
Volume (bbls/d)	72,899	62,395	19,043	16,887	**42,806**
Weighted average fixed WTI price (US$/bbl)	$58.67	$59.68	$59.38	$59.36	**$59.19**
Enhanced WTI Fixed Price Hedges with Sold Put Options(1)					
Volume (bbls/d)	-	-	16,870	24,500	**10,342**
Weighted average fixed WTI price (US$/bbl) / Put option strike price (US$/bbl)	-	-	$59.38 / $52.00	$59.11 / $52.00	**$59.22 / $52.00**
Total WTI hedge volume (bbls/d)	**72,899**	**62,395**	**35,913**	**41,387**	**53,148**
WTI:WCS Differential Hedges					
Volume(2) (bbls/d)	30,150	45,150	32,150	39,150	**36,650**
Weighted average fixed WTI:WCS differential at Edmonton (US$/bbl)	($20.14)	($18.50)	($19.79)	($19.49)	**($19.39)**
Condensate Hedges					
Volume(3) (bbls/d)	19,149	23,298	23,208	23,208	**22,216**
Average % of WTI landed in Edmonton (%)	103%	101%	100%	100%	**101%**

(1) *Includes fixed price swaps and sold put options entered into for the second half of 2020. At an average 2H20 WTI price of US$52.00 per barrel or higher, MEG's effective WTI hedge price for 2H20 is US$59.30 per barrel. Illustratively, at an average 2H20 WTI price of US$50.00 and US$45.00 per barrel, MEG's effective WTI hedged price for 2H20 is US$58.22 and US$55.55 per barrel, respectively.*

(2) *2020 includes approximately 13,200 bbls/d of physical forward rail blend sales at a fixed WTI:AWB differential.*

(3) *2020 includes approximately 7,250 bbls/d (annual average) of physical forward condensate purchases. Where applicable, the average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.*

The Corporation's 2020 non-energy operating costs and general and administrative expense are targeted to be in the range of $4.50 - $4.90 per barrel and $1.75 - $1.85 per barrel, respectively.

Conference Call

A conference call will be held to review MEG's full-year 2019 operating and financial results at 6:30 a.m. Mountain Time (8:30 a.m. Eastern Time) on Thursday, March 5th, 2020. To participate, please dial the North American toll-free number 1-888-390-0546, or the international call number 1-587-880-2171.

A recording of the call will be available by 12 noon Mountain Time (2 p.m. Eastern Time) on the same day at www.megenergy.com/investors/presentations-and-events.

Operational and Financial Highlights

	Three months ended December 31		Year ended December 31	
($ millions, except as indicated)	**2019**	**2018**	**2019**	**2018**
Bitumen production - bbls/d	**94,566**	87,582	**93,082**	87,731
Steam-oil ratio	**2.27**	2.22	**2.22**	2.19
Bitumen sales - bbls/d	**94,347**	88,283	**93,587**	87,051
Bitumen realization - $/bbl	**46.86**	15.31	**53.21**	36.69
Net operating costs - $/bbl(1)	**5.87**	4.55	**5.24**	5.09
Non-energy operating costs - $/bbl	**4.49**	4.25	**4.61**	4.62
Cash operating netback - $/bbl(2)	**28.33**	7.14	**32.15**	17.61
Adjusted funds flow(3)	**157**	(37)	**726**	180
Per share, diluted	**0.51**	(0.13)	**2.41**	0.60
Revenue	**992**	520	**3,931**	2,733
Net earnings (loss)	**26**	(199)	**(62)**	(119)
Per share, diluted	**0.09**	(0.67)	**(0.21)**	(0.40)
Capital expenditures	**72**	144	**198**	622
Cash and cash equivalents	**206**	318	**206**	318
Long-term debt - C$	**3,123**	3,740	**3,123**	3,740
Long-term debt - US$	**2,409**	2,741	**2,409**	2,741

(1) Net operating costs include energy and non-energy operating costs, reduced by power revenue.
(2) Cash operating netback is a non-GAAP measure and does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Refer to "Non-GAAP Measures" of this press release.
(3) Refer to Note 26 of the 2019 audited annual consolidated financial statements for further detail.

ADVISORY

Basis of Presentation

MEG prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS") and presents financial results in Canadian dollars ($ or C$), which is the Corporation's functional currency.

Non-GAAP Measures

Certain financial measures in this news release including free cash flow and cash operating netback are non-GAAP measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Free Cash Flow

Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt. Free cash flow is calculated as adjusted funds flow less capital expenditures.

	Three months ended December 31		**Year ended December 31**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Net cash provided by (used in) operating activities	**$225**	$94	**$631**	$280
Net change in non-cash operating working capital items	**(52)**	(159)	**110**	(111)
Funds flow from (used in) operations	**$173**	$(65)	**$741**	$169
Adjustments:				
Other income[1]	**(20)**	-	**(20)**	-
Decommissioning expenditures	**1**	1	**2**	5
Net change in other liabilities[2]	**3**	3	**3**	3
Realized gain on foreign exchange derivatives[3]	**-**	-	**-**	(35)
Defense costs related to unsolicited bid[4]	**-**	19	**-**	19
Payments on onerous contracts	**-**	5	**-**	19
Adjusted funds flow	**$157**	$(37)	**$726**	$180
Capital expenditures	**(72)**	(144)	**(198)**	(622)
Free cash flow	**$85**	$(181)	**$528**	$(442)

(1) During the fourth quarter of 2019, the Corporation agreed to relieve the Alberta Petroleum Marketing Commission ("APMC") of all obligations pursuant to a crude oil purchase and sale agreement in exchange for a payment of $20 million.

(2) Excludes change in long-term cash-settled stock-based compensation liability.

(3) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

(4) The Corporation incurred costs of $19 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.

Cash Operating Netback

Cash operating netback is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, transportation and storage, third- party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

Forward-Looking Information

Certain statements contained in this news release may constitute forward-looking statements within the meaning of applicable Canadian securities laws. These statements relate to future events or MEG's future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "plan", "intend", “target”, “potential” and similar expressions are intended to identify forward-looking statements.

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this press release contains forward looking statements with respect to our forecast 2020 capital budget and its allocation, timing of completion of the Phase 2B Brownfield expansion, , free cash flow and amount of debt repayment, expected improvement in average pricing against the AWB index price when increased capacity on the Flanagan and Seaway pipelines comes online later in 2020, expected productive capacity post the 2020 plant turnaround, production, non-energy operating costs, general and administrative expenses and annual cash cost and interest savings as a result of debt repayment and refinancing and focus and strategy.

Forward-looking information contained in this press release is based on management's expectations and assumptions regarding, among other things: future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, foreign exchange rates and interest rates; the recoverability of MEG's reserves and contingent resources; MEG's ability to produce and market production of bitumen blend successfully to customers; extent and timelines of the Alberta Government’s mandatory production curtailment program, future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which MEG conducts and will conduct its business; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

These risks include, but are not limited to: risks associated with the oil and gas industry, for example, the securing of adequate access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related to such prices and rates; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with MEG’s future phases and the expansion and/or operation of MEG’s projects; risks and uncertainties related to access to pipeline and rail transportation; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG’s turnarounds, and of future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; uncertainties arising in connection with acquisitions and/or dispositions of assets; and the potential costs associated with ongoing litigation cases.

Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in MEG's most recently filed Annual Information Form ("AIF"), along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the Company's website at www.megenergy.com/investors and through the SEDAR website at www.sedar.com.

The forward-looking information included in this news release is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this news release is made as of the date of this news release and MEG assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

This news release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about MEG's prospective results of operations including, without limitation, cash flow, capital expenditures, production, operating costs and general and administrative expenses, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. MEG's actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits MEG will derive therefrom. MEG has included the FOFI in order to provide readers with a more complete perspective on MEG's future operations and such information may not be appropriate for other purposes. MEG disclaims any intention or obligation to update or revise any FOFI statements, whether as a result of new information, future events or otherwise, except as required by law. MEG's 2019 Annual Management's Discussion and Analysis ("MD&A") and 2019 Annual Consolidated Financial Statements are available at www.megenergy.com/investors and at www.sedar.com.

About MEG

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells Access Western Blend ("AWB" or "blend") to refiners throughout North America and internationally.

For further information, please contact:

Investor Relations
T 403.767.6206
E invest@megenergy.com

Media Relations
T 403.767.1485
E media@megenergy.com