MEG Energy

Sustainable. Innovative. Responsible.

March 2020 Corporate Presentation

TSX | MEG

Corporate Priorities

Building on 2019 Success

Focus on **free cash flow generation**

Existing production capacity, supported by low operating costs and low sustaining capital, generates material free cash flow

- ✓ 18% reduction in G&A relative to 2018
- ✓ Disciplined capital investment focused on sustaining current production
- ✓ 1/3 of sales to higher priced USGC market; ~US$2.80 / bbl premium on average vs. Canada
- ✓ Highest annual average production in MEG's history

Debt reduction and **financial liquidity**

Free cash flow will continue to be earmarked for debt reduction

- ✓ Reduced and extended modified covenant-lite credit facilities to 2024
- ✓ **~$630 MM debt reduction to date, including $132 MM in 2020**
- ✓ Annualized cash savings of approximately **$45 MM**
- ✓ De-risked balance sheet - first maturity in 2024

2020 Priorities

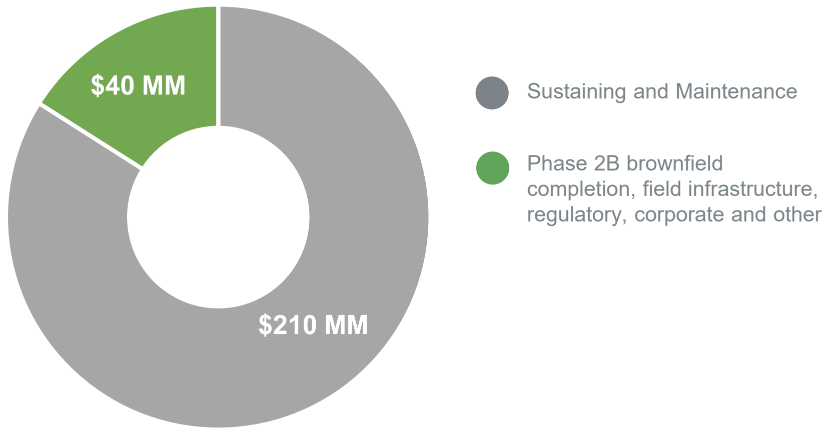
- Continue to **reduce debt via free cash flow generation** – 70% of 1H20 WTI hedged at >US$59 per barrel, 55% hedged for FY20
- Increase barrels sold into **high value USGC pricing** – expect >**50% of sales** exposed to USGC pricing in 2H20 via Flanagan capacity increase and rail
- On-going focus on efficient, **low cost operations**

2020 Outlook

Capital budget of $250 million prioritizes financial strength and maximizing free cash flow, fully funded from a portion of expected adjusted funds flow

- Production guidance of 94,000 – 97,000 bbls/d includes impact of turnaround
- Expect to exit 2020 at ~100,000 bbls/d
- ~30,000 bbls/d contracted rail capacity
- Capital budget focused on sustaining & maintenance
- Guidance includes lowest ever non-energy opex and G&A / bbl
- 2020 cash flow is substantially hedged to protect sustaining capital and debt repayment objectives
- Management remains committed to applying all free cash flow above its 2020 capital investment plan to further debt reduction

2020 Capital Budget $250 MM



Operational Guidance

	2020 Guidance
Production[1] – average (bbls/d)	94,000 – 97,000
Non-energy operating costs ($/bbl)	$4.50 - $4.90
G&A costs ($/bbl)	$1.75 - $1.85

1. 2020 Production guidance includes impact of planned turnaround in Q3, incrementally, Q3 blend sales are expected to be impacted by 10,000 – 15,000 bbls/d of blend reflecting linefill requirements for volume increase from 50 kbbls/d to 100 kbbls/d mid 2020 on the Flanagan South pipeline.

Commodity Price Hedging

Strategy focused on protecting capital program while providing flexibility to fund debt reduction; ~70% of H1 WTI exposure is hedged with 55% hedged in 2020 on average; Hedging program supports free cash flow generation in 2020 across range of price outcomes

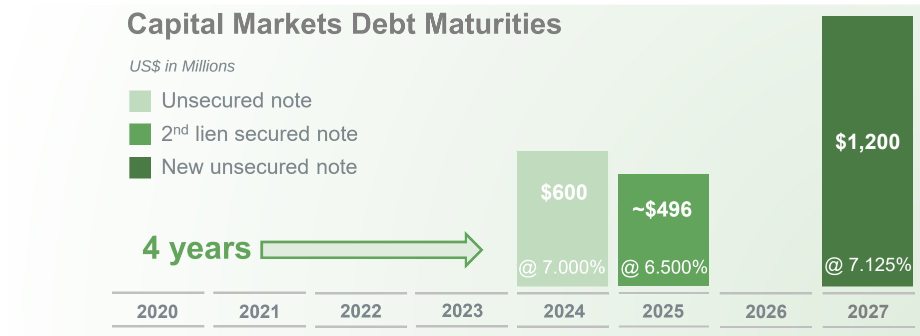
As of March 3rd, 2020	Q1 2020	Q2 2020	Q3 2020	Q4 2020	2020
WTI Hedges					
WTI Fixed Price Hedges					
Volume (bbl/d)	72,899	62,395	19,043	16,887	42,806
Weighted average fixed WTI price (US$/bbl)	$58.67	$59.68	$59.38	$59.36	$59.19
Enhanced WTI Fixed Price Hedges with Sold Put Options					
Volume *(bbl/d)*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

Note: MEG's hedging portfolio also includes certain condensate hedges in 2021 and 2022

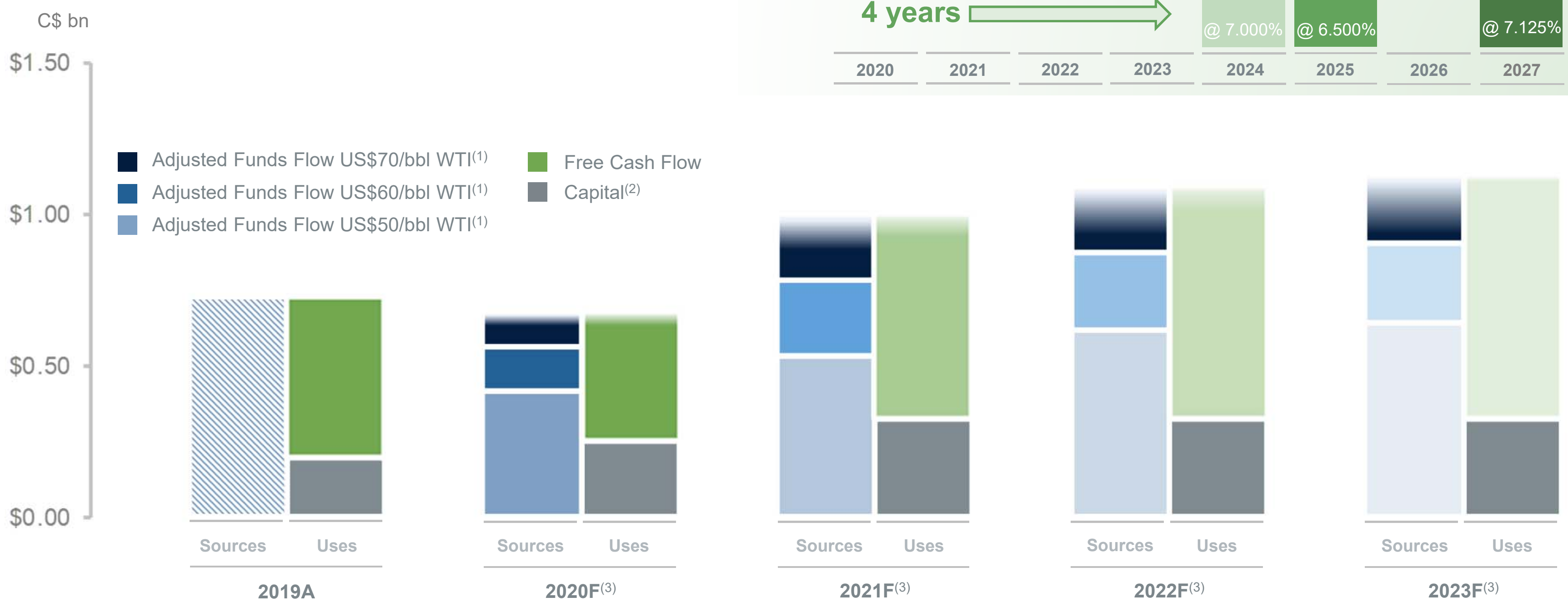
1. *Includes fixed price swap and sold put option entered into for the second half of 2020. At an average 2H20 WTI price of US$52.00 or higher, MEG's effective hedge price for 2H20 is US$59.29 per barrel. Illustratively, at an average 2H20 WTI price of US$50.00 and US$45.00, MEG's effective hedged price for 2H20 is US$58.25 and US$55.60 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.*

100,000 bbls/d Builds Material Free Cash Flow

Substantial runway to continue prioritized debt reduction



Sources & Uses of Funds



Improving egress increases funds flow

Sales to higher-priced USGC market increases from approximately one-third to two-thirds of blend volumes

Note: Adjusted funds flow and free cash flow are referred to throughout this presentation; please see Disclosure Advisories for further details
See page 16 for key assumptions – sensitivity to WTI in 2021 to 2023 includes a corresponding impact to differentials

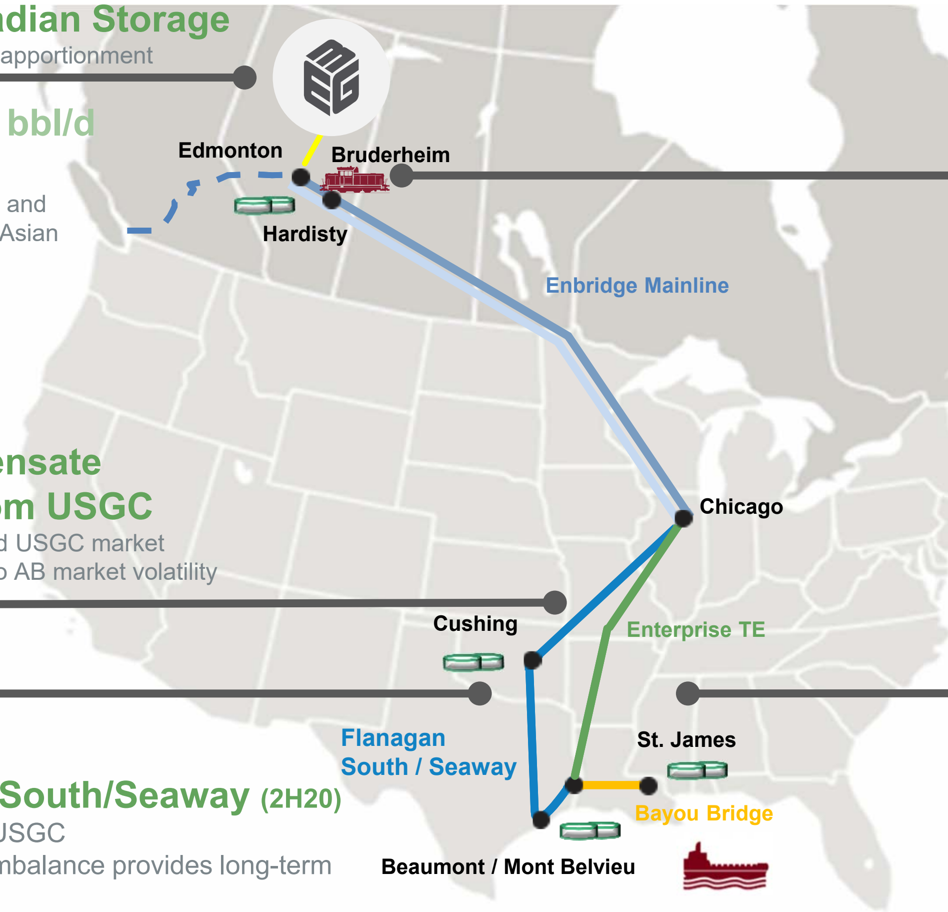
1. *Actual 2019 adjusted funds flow. 2020+ adjusted funds flow assumes average WTI price for the full year and includes current hedge book.*
2. *Capital expenditure assumes medium term sustaining and maintenance capital of $8 / bbl; 2020 forecast based on market guidance. Forecasted figures from 2021F through 2023F are subject to board approval.*
3. *Forecast production assumes 94,000 – 97,000 bbls/d in 2020 and 100,000 bbls/d in each year thereafter.*

Assets to Access High Value Markets

Strategic marketing assets de-risk the business and enhance net realized bitumen price

1.4 mmbbl
Western Canadian Storage
- Manages Enbridge apportionment

Future 20,000 bbl/d on TMX
- Access to tidewater and delivery to growing Asian heavy oil market



30,000 bbl/d*
rail loading capacity
- Secures apportionment-protected sales
- Sales made FOB at Edmonton, although price exposure to USGC retained on ~50% of 2020 volumes

40-50% condensate purchases from USGC
- Access over-supplied USGC market
- Reduces exposure to AB market volatility

100 mbbl/d
on Flanagan South/Seaway (2H20)
- Direct access to USGC
- Supply/demand imbalance provides long-term pricing support
- None of capacity is dependent on Line 3 replacement

1.4 mmbbl
U.S. storage
- Optimizes Flanagan commitments and exports

Marine export access
- From MEG assets at Beaumont and St. James

** Based on 100 rail cars per train with 600 bbls / car and 100% efficiency*

Blend Sales by Market

Anticipate growing deliveries to USGC from 1/3 to >50% in H2 2020

Actual 2019 Results **US$/bbl, except as indicated**	**Edmonton (US$/bbl)** **Pipeline**	 **FOB Rail**	**U.S. Gulf Coast (US$/bbl)** **Pipeline**	 **Delivered Rail**	**TOTAL (US$/bbl)**	**TOTAL (C$/bbl)**[3]
WTI	$ 57.03	$ 57.03	$ 57.03	$ 57.03	$ 57.03	$ 75.67
Differential - WTI:AWB at sales point	(15.88)	(11.52)	(1.28)	(3.78)	(10.84)	$ (14.38)
Blend sales price	41.15	45.51	55.75	53.25	46.19	61.29
Transportation and storage[1]	(1.71)	(4.28)	(10.67)	(23.54)	(5.70)	$ (7.56)
Transportation and storage Christina Lake to Edmonton[2]	1.71	1.71	1.71	1.71	1.71	$ 2.27
AWB sales price, net of transportation	$ 41.15	$ 42.94	$ 46.79	$ 31.42	$ 42.20	$ 56.00
Average AWB sales price by location, net of transportation		**$ 41.36**		**$ 43.93**		
Total blend sales - mbbl/d	78	11	36	8		134
% of total sales	58%	9%	27%	6%		100%

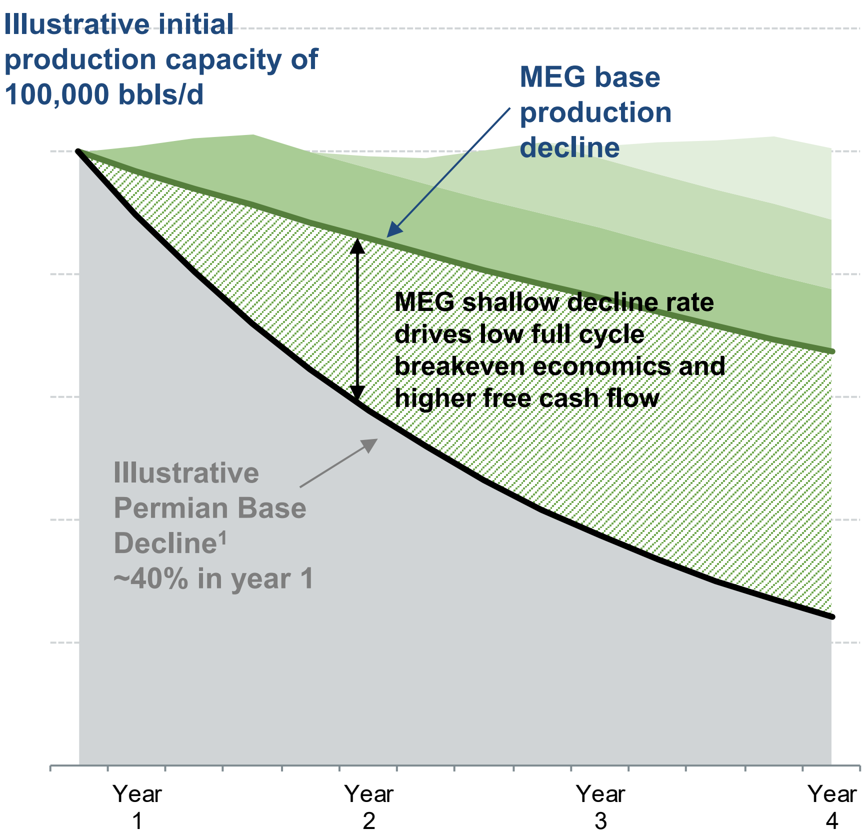
Capacity on pipe to USGC doubles in mid-2020

1. *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$10.84/bbl for the year ended December 31, 2019 compared to C$8.42 per barrel for the year ended December 31, 2018.*
2. *Includes all transportation costs associated with moving barrels of blend from Christina Lake to Edmonton sales point.*
3. *Results are translated at the average foreign exchange rate of C$1.3269.*

Low Breakeven Price in Sustainable Asset

Low decline asset base allows for production capacity of 100,000 bbls/d to be maintained with low sustaining capital, enhancing free cash flow

In situ assets have low decline profile *(10 – 15% annually)*



- Unique thermal oil decline profile results in low annual sustaining capital – approximately C$8 / bbl
- 2.1 bn bbl of 2P reserves[2] at Christina Lake allows for production of ~ 60 years from existing, well delineated asset
- Based on low sustaining capital and attractive operating cost profile, **current full cycle (including sustaining capital) corporate breakeven of ~US$45/bbl WTI[3]**

1. *Based on estimated PDP corporate decline for Permian producers as per industry research. Profile is illustrative only and not meant to represent a production forecast for MEG or others. Source: MEG and Barclays*
2. *See additional disclosure with respect to MEG's reserves in its AIF.*
3. *Assumes production of 100,000 bbls/d, WTI:WCS differential of 28%, $8/bbl sustaining capital, and condensate cost at 100% of WTI.*

ESG Highlights

MEG's focus on ESG supported via executive committee – integrated into all aspects of the business

GHG Emissions Intensity 20% below in situ industry average

NO Lost Time Incidents at our Christina Lake facility

Decrease of 68% in water withdrawal intensity since 2013

Average Steam Oil Ratio (SOR) 20% lower than SAGD industry average

50% improvement in well pad land use

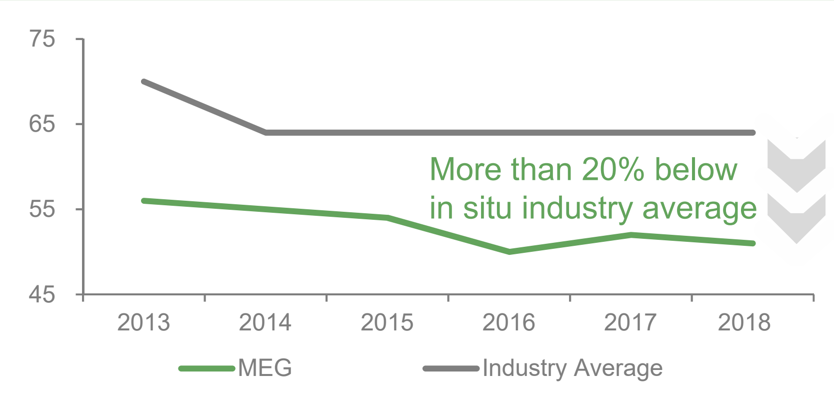
Nearly $93 Million in Indigenous business spend

Data in ESG report based on 2018 results, additional information can be found at https://www.megenergy.com/sustainability

Canadian energy producers are among the most responsible in the world;
MEG is a leader in environmental performance within the sector

Environmental Leader

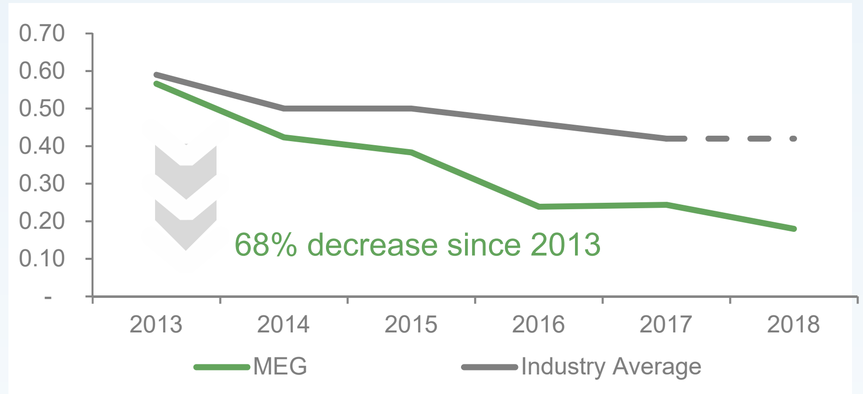
Net GHG Intensity *(kg CO_2e/bbl))*



MEG is a leader in lowering Greenhouse Gas (GHG) intensity

- Technological innovation, such as eMSAGP, eMVAPEX and cogeneration have driven MEG's GHG intensity down by 9% since 2013
- MEG has the second lowest net GHG intensity among the in situ peer group
- MEG uses cogeneration at its facilities with excess power being sold into Alberta Power Market – cogeneration results in more efficient use of natural gas and the electricity provided to the power grid had a lower GHG footprint in 2018 than the provincial average, helping to reduce total GHG intensity for provincial consumers

Water Withdrawal Intensity *(bbl water per bbl bitumen)*



MEG does not use any surface water from streams, rivers or lakes in its operations

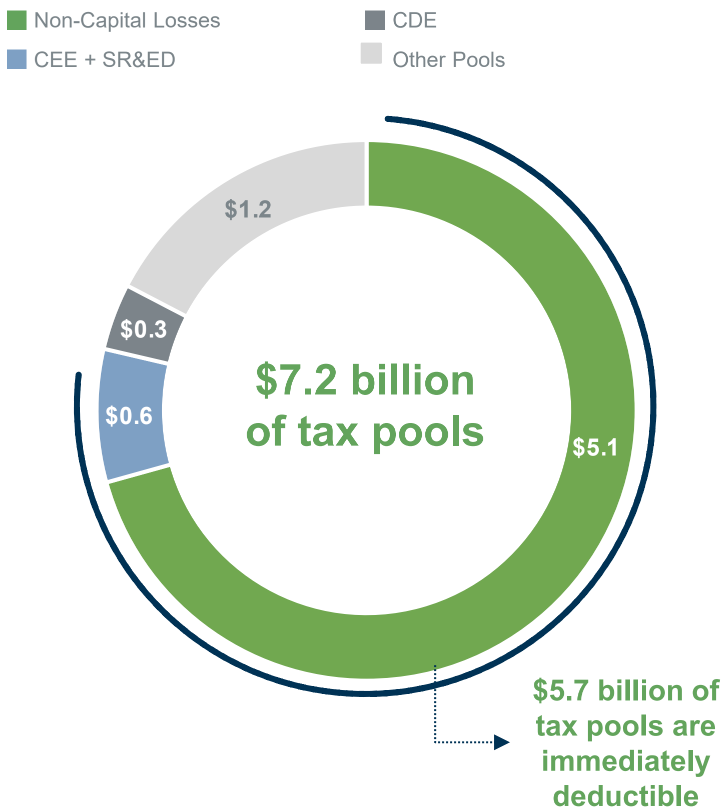
- In 2018, MEG recycled 90% of water recovered from the reservoir to generate steam with remainder coming from deep non-potable sub-surface reservoirs
- Implementation of eMSAGP and eMVAPEX as well as optimization of water recycling technology enables MEG to reduce its total water withdrawal intensity
- MEG's 2018 water withdrawal intensity was 0.18, which is 58% lower than the industry average
- No water used in MEG's processes is discharged into the environment

APPENDIX

Material Unrecognized Value from Tax Pools

$5.7 billion of tax pools immediately deductible

Composition of Tax Pools (C$ billion)



Amount of Pools Utilized by Year[(1)]	Illustrative Value of Tax Pools at 8.0% Discount Rate	
(C$ MM)	(C$ Bn)	(C$/sh)[(2)]
$500	$1.0	$3.15
$1,000	$1.2	$4.05
$1,500	$1.4	$4.40
$2,000	$1.4	$4.65

Maximum Theoretical Value[(3)]		
Total	$1.8 Bn	$5.80/sh[(2)]
Immediately Deductible	$1.4 Bn	$4.55/sh[(2)]

1. *Refers to the amount of tax pools utilized while the pools are fully deductible.*
2. *Tax pool value based on step down in tax rate from 25% to 23% over next three years (tax pools as at December 31, 2019); Value presented per MEG share, using fully diluted shares outstanding as of December 31, 2019.*
3. *Maximum theoretical value is calculated based on 2020 tax rate of 25.0% applied to MEG's total and immediately deductible tax pools, and using fully diluted shares outstanding as of December 31, 2019.*

Inventory of Highly Economic Growth

Optional growth projects identified to support buildout to 210,000 bbls/d at Christina Lake are execution ready – debt repayment takes precedence

Base

~100,000 bbls/d
Current production capacity

- ✓ **Complete**

2B Brownfield Expansion

+13,000 bbls/d

- ✓ **Go forward capital efficiency of ~$10k/bbl/d**
- ✓ CPF substantially complete
- ✓ Well pad capital required to add production

Additional Steam (5th and 6th OTSGs)

+17,000 bbls/d

- ✓ **Capital efficiency of $20-25k/bbl/d**
- ✓ Regulatory approval
- ✓ Engineering
- ✓ Site preparation
- ✓ Equipment purchased

eMVAPEX

+~30,000 bbls/d

- ✓ **Capital efficiency of <$20k/bbl/d**
- ✓ Pilot results exceeding expectation on lowering SOR
- ✓ Short cycle repeatable execution

2B4X Brownfield Expansion

~210,000+ bbls/d

+~52,000+ bbls/d

- ✓ **Capital efficiency of $30-35k/bbl/d**(1)
- ✓ Regulatory approval
- ✓ Engineering
- ✓ Site preparation
- ✓ Equipment purchased

Significant growth options beyond 113,000 bbls/d

Note: Capital efficiency includes both central processing facility and well capital on a full-cycle basis
1. Production capacity of ~52,000 bbl/d at 2.4 SOR, up to ~60,000 bbl/d at 2.1 SOR; Capital efficiency at a 2.1 SOR.

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Disclosure Advisories

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Forward-looking information contained in this presentation 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; 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 laws and Federal and Provincial climate change policies, and the timing and level of government apportionment easing, 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, including the transition to a low carbon environment; the securing of adequate access to markets and transportation infrastructure and to investment capital ; 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, environmental laws, and Federal and Provincial climate change policies and curtailment of production policies, and, MEG's ability to implement sales under the Alberta Government's Special Production Allowance ("SPA") program; risks related to increased activism and public opposition to fossil fuel development; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates; 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 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; and uncertainties arising in connection with any future acquisitions and/or dispositions of assets.

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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.

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Disclosure Advisories

Pricing Assumptions[1]

The following table shows the key assumptions used in the cash flow and free cash flow estimates included in this presentation:

		2019A	2020F	2021F	2022F	2023F
WTI	US$/bbl	$57.03	$60.00	$60.00	$60.00	$60.00
WTI:WCS Differential	US$/bbl	$12.76	$16.75	$18.00	$16.00	$16.00
WTI:AWB Gulf Coast Differential	US$/bbl	$1.77	$6.25	$7.50	$7.50	$7.50
Condensate (% of WTI)	%	98%	100%	100%	100%	100%
Delivered Gas Cost	C$/mcf	$2.20	$2.25	$2.35	$2.50	$2.55
Exchange Rate	C$/US$	1.33	1.29	1.29	1.29	1.29
Mainline Apportionment	%	43%	45%	30%	15%	0%
2020 Funds Flow Sensitivities[2]						
WTI (US$/bbl) - $1/bbl change	C$ MM		$8			
WTI:WCS Diff. (US$/bbl) - $1/bbl change	C$ MM		$20			
WTI:AWB Diff. (US$/bbl) - $1/bbl change	C$ MM		$25			
Condensate (% of WTI) - 1% change	C$ MM		$12			
Gas Cost (C$/mcf) - $0.25/mcf change	C$ MM		$10			
Exchange Rate - $0.01 change	C$ MM		$7			

Note: 2019 actual pricing shown

1. *Differentials and exchange rate remain unchanged across WTI scenarios in 2020. Beginning in 2021, at US$50/bbl WTI, F/X is adjusted to C$1.35 and differentials are narrowed by US$2/bbl. At US$70/bbl WTI, F/X is adjusted to C$1.22 and differentials are widened by US$2/bbl.*
2. *Including current hedge position.*

Disclosure Advisories

Non-GAAP Measures

This presentation refers to the non-GAAP measure of free cash flow, as well as adjusted funds flow which is defined in Note 26 of the annual 2019 Financial Statements. These terms may not be comparable to similar measures provided by other companies and are not intended to represent net cash provided by (used in) operating activities. These financial measures should not be considered in isolation or as an alternative to, or more meaningful than, MEG's consolidated statement of cash flow as determined in accordance with IFRS, as an indicator of financial performance.

Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of the capacity of the business to repay debt, incur discretionary capital or increase returns to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures.

	Three months ended December 31		Year ended December 31	
($mm)	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)

Note: Values are rounded to the nearest million

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 one-time 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.*

Investor Relations

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